TRANSALTA CORPORATION
THIRD QUARTER REPORT FOR 2012

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") contains forward looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See the Forward Looking Statements section of this MD&A for additional information.

This MD&A should be read in conjunction with the unaudited interim condensed consolidated financial statements of TransAlta Corporation as at and for the three and nine months ended Sept. 30, 2012 and 2011, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2011 Annual Report. In this MD&A, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation' and 'TransAlta' refers to TransAlta Corporation and its subsidiaries. The condensed consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated Oct. 25, 2012. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading, and Corporate. In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Condensed Consolidated Statements of Earnings and Condensed Consolidated Statements of Financial Position items. While individual line items in the Condensed Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of these items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive Income (Loss) ("AOCI") in the equity section of the Condensed Consolidated Statements of Financial Position.

HIGHLIGHTS

Third Quarter Highlights

Performance from the Generation Segment improved quarter over quarter with overall fleet availability increasing seven per cent to 90.9 per cent despite higher planned outages. While prices in both Alberta and the Pacific Northwest remained softer period-over-period, the increased availability drove a $51 million increase in Generation comparable gross margins. The Generation comparable gross margins for the quarter were $386 million.

The Energy Trading Segment reported a decrease in gross margins of $61 million to a negative gross margin of $16 million for the quarter as a result of unexpected weather patterns and unfavourable market expectations relative to positions held.

Funds from Operations ("FFO") increased $64 million in the quarter to $232 million, driven by increased cash earnings after adjusting for unrealized losses on risk management activities and cash settlements of contracts previously recognized in earnings.

A quarterly dividend of $0.29 per share was declared on common shares, returning value to shareholders.

We reported net earnings attributable to common shareholders of $56 million ($0.24 per share), up from $50 million ($0.22 per share) in 2011, which included:

- Sundance Units 1 and 2 asset impairment reversal of $31 million
- Inventory writedown reversal of $18 million
- Gain on sale of collateral at MF Global Inc. of $11 million

These items, along with the impact of the de-designated hedges, have been adjusted in calculating comparable earnings of $41 million ($0.18 per share), down from $61 million ($0.27 per share) in 2011. The decrease in comparable earnings is primarily due to the loss in Energy Trading.

We acquired the 125 megawatt ("MW") Solomon power station for U.S.$318 million. The power station is fully contracted and is expected to generate pre-financing cash flows of approximately $40 million per year and be accretive to both earnings and free cash flow per share.

Year-To-Date Highlights

Overall fleet availability increased over four per cent despite higher planned major maintenance. The Generation comparable gross margins have increased $18 million to $1,103 million.

The Energy Trading Segment reported a decrease of $107 million to a negative gross margin of $10 million for the period.

FFO decreased $49 million for the first nine months to $571 million, primarily due to lower comparable earnings. Excluding the impact of the Sundance Units 1 and 2 arbitration ruling, we remain on track to deliver at the low end of our stated range of $800 - $900 million for the full year.

We reported a net loss attributable to common shareholders of $652 million ($2.85 per share), down from net earnings attributable to common shareholders of $266 million ($1.20 per share) in 2011, which included:

- Centralia asset impairment of $329 million
- Writeoff of deferred tax assets of $169 million
- Impact of Sundance Unit 1 and 2 arbitration results of $189 million
- Gain on sale of collateral at MF Global Inc. of $11 million

These items, along with the impact of the de-designated hedges, have been adjusted in calculating comparable earnings of $64 million ($0.28 per share), down from $201 million ($0.91 per share) in 2011. The decrease in comparable earnings is primarily due to the loss in Energy Trading and higher planned major maintenance.

The following table depicts key financial results and statistical operating data:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Availability (%)[1]	**90.9**	83.9	**88.1**	83.7
Production (GWh)[1]	**10,155**	10,368	**27,870**	29,350
Revenues	**538**	629	**1,601**	1,962
Gross margin[2]	**330**	371	**1,055**	1,307
Operating income (loss)[2]	**132**	106	**(90)**	523
Comparable operating income[3]	**125**	120	**300**	421
Net earnings (loss) attributable to common shareholders	**56**	50	**(652)**	266
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.24**	0.22	**(2.85)**	1.20
Comparable net earnings per share[3]	**0.18**	0.27	**0.28**	0.91
Comparable EBITDA[3]	**254**	237	**699**	772
Funds from operations[3]	**232**	168	**571**	620
Funds from operations per share[3]	**0.99**	0.75	**2.49**	2.79
Cash flow from operating activities	**14**	212	**275**	503
Free cash flow (deficiency)[3]	**78**	(5)	**54**	176
Dividends paid per common share	**0.29**	0.29	**0.87**	0.87

As at	**Sept. 30, 2012**	Dec. 31, 2011
Total assets	**9,423**	9,736
Total long-term liabilities	**5,016**	4,918

AVAILABILITY & PRODUCTION

Availability for the three and nine months ended Sept. 30, 2012 increased compared to the same periods in 2011 primarily due to lower planned and unplanned outages at Centralia Thermal and lower unplanned outages at the Alberta coal Power Purchase Arrangement ("PPA") facilities, partially offset by higher planned outages at the Alberta coal PPA facilities.

Production for the three and nine months ended Sept. 30, 2012 decreased 213 gigawatt hours ("GWh") and 1,480 GWh, respectively, compared to the same periods in 2011 due to higher economic dispatching at Centralia Thermal, higher planned outages at the Alberta coal PPA facilities, lower PPA customer demand, and market curtailments, partially offset by lower planned and unplanned outages at Centralia Thermal, the commencement of commercial operations at Keephills Unit 3, lower unplanned outages at the Alberta coal PPA facilities, and higher hydro volumes.

The outages at Centralia Thermal did not negatively impact our gross margins for the three and nine months ended Sept. 30, 2012 as we were able to extend our planned outage to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Overall fleet availability, after adjusting for the extended planned outage at Centralia, was 91.7 per cent (Sept. 30, 2011 - 88.3 per cent) and 90.3 per cent (Sept. 30, 2011 - 88.2 per cent) for the three and nine months ended Sept. 30, 2012, respectively.

(1) Availability and production includes all generating assets (generation operations, finance lease, and equity investments).

(2) These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of these items.

(3) These items are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

NET EARNINGS (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings (loss) attributable to common shareholders for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net earnings attributable to common shareholders, 2011	50	266
Increase in Generation comparable gross margins	51	18
Mark-to-market movements and de-designations - Generation	(51)	(183)
Decrease in Energy Trading gross margins	(61)	(107)
Decrease in operations, maintenance, and administrative costs	21	25
Increase in depreciation and amortization expense	(7)	(41)
Decrease (increase) in asset impairment charges	46	(310)
Recovery of (increase in) inventory writedown, net of consumption	28	(14)
Increase in net interest expense	(4)	(31)
Decrease in equity income	(14)	(21)
Impact of Sundance Units 1 and 2 arbitration	(7)	(254)
(Increase) decrease in income tax expense	(5)	3
Increase in preferred share dividends	(4)	(10)
Increase in gain on sale of collateral	15	15
Other	(2)	(8)
Net earnings (loss) attributable to common shareholders, 2012	**56**	**(652)**

Generation comparable gross margins, excluding the impact of mark-to-market movements, for the three and nine months ended Sept. 30, 2012 increased compared to the same period in 2011 primarily due to higher hydro margins, lower unplanned outages at the Alberta coal PPA facilities, and the commencement of commercial operations of Keephills Unit 3, partially offset by higher planned outages at the Alberta coal PPA facilities and unfavourable coal costs.

Mark-to-market movements decreased for the three and nine months ended Sept. 30, 2012 compared to the same periods in 2011 due to the recognition of mark-to-market gains in 2011 resulting from certain power hedging relationships being deemed ineffective, which reduced the gains on contracts recognized in 2012.

For the three months ended Sept. 30, 2012, Energy Trading gross margins decreased compared to the same period in 2011 primarily due to the impact of unexpected weather patterns and unfavourable market expectations on power and gas pricing for trading positions held.

Energy Trading gross margins for the nine months ended Sept. 30, 2012 decreased compared to the same period in 2011 primarily due to gas supply conditions that impacted gas prices, unexpected weather patterns, power plant outages, and the impact of unfavourable market expectations on power and gas pricing for trading positions held.

Operations, maintenance, and administrative ("OM&A") costs for the three and nine months ended Sept. 30, 2012 decreased primarily due to lower compensation costs.

Depreciation and amortization expense for the three and nine months ended Sept. 30, 2012 increased compared to 2011 primarily due to an increased asset base, largely due to the commencement of commercial operations at Keephills Unit 3, and asset retirements, partially offset by a reduction in depreciation expense due to the change in the economic useful lives of Alberta coal-fired plants.

Asset impairment charges for the three months ended Sept. 30, 2012 decreased due to the reversal of asset impairment charges recognized in the prior quarter on Sundance Units 1 and 2 due to the change in the economic useful life of these assets and the recognition of lower asset impairments in the comparable quarter in 2011.

For the nine months ended Sept. 30, 2012, asset impairment charges increased due to the recognition of a higher amount of impairment charges on the Centralia Thermal plant and on assets within our renewables fleet, in order to write these assets down to their fair values. The impairment charges can be reversed in future periods if the forecasted cash flows generated by these plants improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

During the three months ended Sept. 30, 2012, $8 million of inventory writedowns taken previously were reversed, due to a recovery in power prices and reduced operating costs. An additional $20 million benefit, reflected in Generation gross margins, resulted from the consumption of previously written down inventories.

The inventory writedown recorded in the nine months ended Sept. 30, 2012 is due to a $34 million net writedown of coal inventories resulting from de-designation of the hedges at the Centralia Thermal plant and the continued low price environment in the Pacific Northwest. The de-designation prevents us from including these contracts as part of the calculation of the net recoverable amount of the inventory. A $20 million benefit, reflected in Generation gross margins, resulted from the consumption of previously written down inventories.

Net interest expense for the three months ended Sept. 30, 2012 increased compared to the same periods in 2011 due to lower capitalized interest, partially offset by lower interest rates and lower amortization of financing costs.

For the nine months ended Sept. 30, 2012, net interest expense increased compared to the same periods in 2011 due to lower capitalized interest and higher interest rates, partially offset by lower debt levels.

Equity income for the three months ended Sept. 30, 2012 decreased due to higher unplanned outages and unfavourable pricing at CE Generation, LLC (“CE Gen”).

For the nine months ended Sept. 30, 2012, equity income decreased due to higher planned and unplanned outages and unfavourable pricing at CE Gen.

For the three months ended Sept. 30, 2012, Sundance Units 1 and 2 arbitration costs increased due to additional interest, legal, and other costs.

Sundance Units 1 and 2 arbitration for the nine months ended Sept. 30, 2012 increased due to the results of the arbitration being released and recorded during the second quarter of 2012.

Income tax expense for the three months ended Sept. 30, 2012 increased compared to the same period in 2011 due to higher net earnings.

Income tax expense for the nine months ended Sept. 30, 2012 decreased compared to the same period in 2011 due to lower net earnings which included the impact of the Sundance Units 1 and 2 arbitration, the positive resolution of certain outstanding tax matters, partially offset by the writeoff of $169 million in income tax assets related to our U.S. operations, which have been impacted by the Centralia Thermal plant valuation.

The preferred share dividends for the three and nine months ended Sept. 30, 2012 increased compared to the same periods in 2011 due to a higher balance of preferred shares outstanding during 2012.

During the third quarter, we sold our claim against MF Global Inc. pertaining to the return of collateral, resulting in a gain.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

Funds from operations for the three months ended Sept. 30, 2012 increased $64 million compared to the same period in 2011 primarily due to improved net earnings after adjusting for non-cash adjustments, primarily unrealized losses from risk management activities and cash settlements of contracts previously recognized in earnings.

For the nine months ended Sept. 30, 2012, funds from operations decreased $49 million compared to the same period in 2011 primarily due to lower comparable net earnings, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings.

Free cash flow for the three months ended Sept. 30, 2012 increased $83 million compared to the same period in 2011 due to the increase in funds from operations and lower cash dividends paid as a result of increased participation in the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan").

For the nine months ended Sept. 30, 2012, free cash flow, after excluding the impact of the Sundance Units 1 and 2 arbitration from earnings, decreased $122 million compared to the same period in 2011 due to the decrease in funds from operations and higher sustaining capital and productivity expenditures. A significant part of the sustaining capital and productivity expenditures incurred during 2012 relates to more comprehensive planned major maintenance, primarily at Keephills Units 1 and 2, including significant component replacements that should not be replaced again over the balance of the life of the plant.

SIGNIFICANT EVENTS

Three months ended Sept. 30, 2012

Sale of Common Shares

On Sept. 13, 2012, we completed our public offering of 19,250,000 common shares and on Sept. 20, 2012, the underwriters exercised in part their over-allotment option to purchase 1,992,000 common shares, all at a price of $14.30 per common share, which resulted in total gross proceeds of $304 million. The proceeds of the offering were used to partially fund the acquisition of the Solomon power station in Australia, to fund the construction of our 68 MW New Richmond wind project, to repay short-term debt, and for general corporate purposes.

Acquisition of Solomon Power Station

On Sept. 28, 2012, we announced that we completed the acquisition from Fortescue Metal Groups Ltd. ("Fortescue") of its 125 MW natural gas- and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility is currently under construction and is expected to be commissioned in the fourth quarter of 2012. The facility will be fully contracted with Fortescue under a long-term Power Purchase Agreement ("Agreement") with an initial term of 16 years, commencing in October 2012, after which Fortescue will have the option to either extend the Agreement by an additional five years under the same terms, or to acquire the facility. The facility and associated Agreement will be accounted for as a finance lease with TransAlta being the lessor.

Sundance Unit 6

On Aug. 18, 2011 the Sundance Unit 6 Generator Step-Up Transformer was damaged as a result of a fire. We gave notice and claimed force majeure relief under the PPA. We have been refunded the penalties that were paid during the outage, a portion of which has been provided for resulting in a net charge of $18 million in net earnings. During the quarter, the PPA Buyer has informed us that they will be taking the matter to arbitration.

MF Global Inc.

During September 2012, we sold our claim against MF Global Inc. pertaining to the return of U.S.$36 million of collateral that we had posted, for net proceeds of U.S.$33 million. During 2011, a reserve of U.S.$18 million was taken on the collateral when the parent company of MF Global Inc. filed for bankruptcy protection. As a result, a pre-tax gain of $15 million ($11 million after tax) was realized. Our claim, filed during the first quarter of 2012, related primarily to our collateral on foreign futures transactions. Please refer to the Significant Events section of our 2011 Annual Report for additional information regarding MF Global Inc.

Reversal of Asset Impairment Charges

During the three months ended Sept. 30, 2012, we reversed $41 million of pre-tax impairment losses previously taken on Sundance Units 1 and 2. The reversal arose as a result of the additional years of merchant operations expected to be realized at Units 1 and 2 due to the recent amendments to Canadian federal regulations. Please refer to the Climate Change and the Environment section of this MD&A for additional information.

Change in Economic Useful Life

As a result of amendments to Canadian federal regulations requiring that coal-fired plants be shut down after a maximum of 50 years of operation, we have reviewed the useful lives of our Alberta coal-fired generating facilities and related coal mining assets and where permitted under the regulations, extended the useful lives to a maximum of 50 years. The previous draft regulations proposed shut down after 45 years. As a result, pre-tax depreciation expense was reduced by $6 million for the three and nine months ended Sept. 30, 2012. Pre-tax depreciation expense is expected to be reduced by $12 million for the year ended Dec. 31, 2012 and by $23 million annually thereafter.

Sale of Preferred Shares

On Aug. 10, 2012, we completed our public offering of 9 million Series E 5.0 per cent Cumulative Redeemable Rate Reset First Preferred Shares, resulting in gross proceeds of $225 million. The proceeds from the offering were used for general corporate purposes, including the funding of capital projects and the reduction of short-term indebtedness of the Corporation.

Centralia Thermal

On July 25, 2012, we announced that we entered into an 11-year agreement to provide electricity from the Centralia Thermal plant to Puget Sound Energy (“PSE”). The contract begins in 2014 and runs until 2025 when the plant is scheduled to be shut down. Under the agreement, PSE will buy 180 MW of firm, base-load power starting in December 2014. In December 2015 the contract increases to 280 MW and from December 2016 to December 2024 the contract is for 380 MW. In the last year of the contract, the contracted volume is 300 MW. The agreement is subject to approval by the Washington Utilities and Transportation Commission.

Centralia Coal Inventory Writedown

During the three and nine months ended Sept. 30, 2012, we recognized a pre-tax $8 million reversal of a previous writedown and a net pre-tax writedown of $34 million, respectively, related to the coal inventory at our Centralia plant. The writedown resulted from the previous de-designation of hedges at Centralia Thermal and the continued low price environment in the Pacific Northwest. During the first quarter, we recognized $85 million of pre-tax gains related to de-designated and ineffective hedges at Centralia Thermal, which had previously been used in calculating the net recoverable amount of the coal inventory at Centralia Thermal. The de-designation prevents us from including these contracts as part of the net recoverable amount of the coal. The $8 million reversal recognized during the three months ended Sept. 30, 2012 is a result of a recovery in power prices and reduced operating costs compared to prior quarters.

During the first quarter, a pre-tax comparable earnings adjustment of $34 million was recognized to offset the effect of the writedown related to inventory that was on hand at the time the hedges were de-designated. Any additional impairments or reversals are also being treated as a comparable earnings adjustment. The overall adjustment is being reversed as the related inventory is consumed. Accordingly, pre-tax comparable earnings for the three and nine months ended Sept. 30, 2012, have been reduced by $28 million, and increased by $5 million, respectively, due to consumption and changes in the net recoverable amount of the inventory. Please refer to the Non-IFRS Measures section of this MD&A.

Nine months ended Sept. 30, 2012

Sundance Units 1 and 2

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of our Sundance facility were shut down due to conditions observed in the boilers at both units. On Feb. 8, 2011, we issued a notice of termination for destruction based on the determination that the units cannot be economically restored to service under the terms of the PPA. Due to the uncertainty of the results of the arbitration ruling, we had been continuing to accrue the capacity payments, net of a provision, and to depreciate the asset.

The matter was heard before an arbitration panel during the second quarter of 2012. On July 20, 2012, the arbitration panel concluded that Units 1 and 2 were not economically destroyed and we will restore the facility to service. The panel has affirmed that the event meets the criteria of force majeure beginning on Nov. 20, 2011 until such time that the units are returned to service. We recorded penalties net of capacity payments, impairment on the units, and interest. The pre-tax earnings impact recorded during the second quarter of 2012 was $247 million. Please refer to *Note 5* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2012 for additional information regarding Sundance Units 1 and 2.

The cost to repair the Units is estimated at approximately $190 million. This investment is expected to start generating cash flow in the fall of 2013.

Asset Impairment Charges

Centralia Thermal

In 2011, the TransAlta Energy Bill (the “Bill”) was signed into law in the State of Washington. The Bill, and a Memorandum of Agreement (the “MoA”) signed on Dec. 23, 2011, which is part of the Bill, provide a framework to transition from coal-fired energy produced at our Centralia Thermal plant by 2025. The Bill and MoA include key elements regarding, among other things, the timing of the shut down of the units and the removal of restrictions on the terms of power contracts that we can enter into.

Since late 2011, a dedicated commercial team has been in place to pursue long-term contracts for the plant. On July 25, 2012, we announced that a long-term power agreement was signed for the supply of power from December 2014 until the facility is fully retired in 2025. As a result, we were able to complete an assessment of whether the carrying amount of the Centralia Thermal plant was recoverable based on an estimate of fair value less costs to sell. The fair value was determined based on the future cash flows expected to be derived from the plant's operations, determined by prices evidenced in the agreement and in the marketplace. A pre-tax impairment charge of $347 million resulted and is included in the Generation Segment.

In addition to the impairment charge, we have written off $169 million of deferred income tax assets as it is no longer probable that sufficient taxable income will be available from our U.S. operations to allow the benefit associated with the deferred income tax assets to be utilized.

The cumulative $516 million impact associated with the plant impairment and writeoff of deferred income tax assets has been adjusted in calculating earnings on a comparable basis. Please refer to the Non-IFRS Measures section of this MD&A.

Sundance Units 1 and 2

During the nine months ended Sept. 30, 2012, we recognized a net pre-tax impairment of $2 million, comprised of the $41 million reversal discussed previously and a $43 million charge in the second quarter that resulted from the conclusion of the Sundance Units 1 and 2 arbitration. Please refer to the Sundance Units 1 and 2 section above for more details.

Other

During the second quarter, we recognized a pre-tax impairment charge of $18 million related to five assets within the renewables fleet. The impairments resulted from the completion of the annual impairment assessment based on estimates of fair value less costs to sell, derived from the long range forecasts and prices evidenced in the market place. The assets were impaired primarily due to expectations regarding lower market prices. The impairment losses are included in the Generation Segment.

Reversals

The impairment charges can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants improve. The reduction of the deferred income tax asset can also be reversed if the estimated taxable income to be generated by our U.S. operations, which include the Centralia Thermal plant, improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Keephills Units 1 and 2 Uprates

During the second quarter, the uprates at Keephills Units 1 and 2 were completed. The total costs of the projects are estimated at $51 million and it is expected that a 40 MW efficiency uprate will be achieved at the facility.

Project Pioneer

On April 26, 2012, Project Pioneer's industry partners announced they would not proceed with the joint carbon capture and storage ("CCS") project. Project Pioneer was a joint effort by TransAlta, the Capital Power Corporation, Enbridge Inc., and the federal and provincial governments to demonstrate the commercial-scale viability of CCS technology.

The first step of the project was to prove the technical and economic feasibility of CCS through a front end engineering and design ("FEED") study before making any major capital commitments. Following the conclusion of the FEED study, the industry partners determined that although the technology works and capital costs were in line with expectations, the revenue from carbon sales and the price of emissions reductions were insufficient to allow the project to proceed. The impact of the cancellation of the project is not expected to be material for our 2012 results.

SUBSEQUENT EVENTS

Strategic Partnership

On Oct. 25, 2012, TransAlta and MidAmerican Energy Holdings Company ("MidAmerican") entered into a new strategic partnership through which the two companies will work together to develop, build, and operate new natural gas-fired electricity generation projects in Canada. The agreement encompasses all new natural gas-fired generation opportunities considered by either TransAlta or MidAmerican in Canada, including our proposed Sundance 7 project. All development and construction, or acquisition, of approved projects will be funded equally by each partner and TransAlta will be responsible for construction management and operation and maintenance of projects that proceed.

BUSINESS ENVIRONMENT

We operate in a variety of business environments to generate electricity, find buyers for the power we generate, and arrange for its transmission. The major markets we own and operate facilities in are Western Canada, the Western U.S., and Eastern Canada. For a further description of the regions in which we operate as well as the impact of prices of electricity and natural gas upon our financial results, *refer to our 2011 Annual MD&A.*

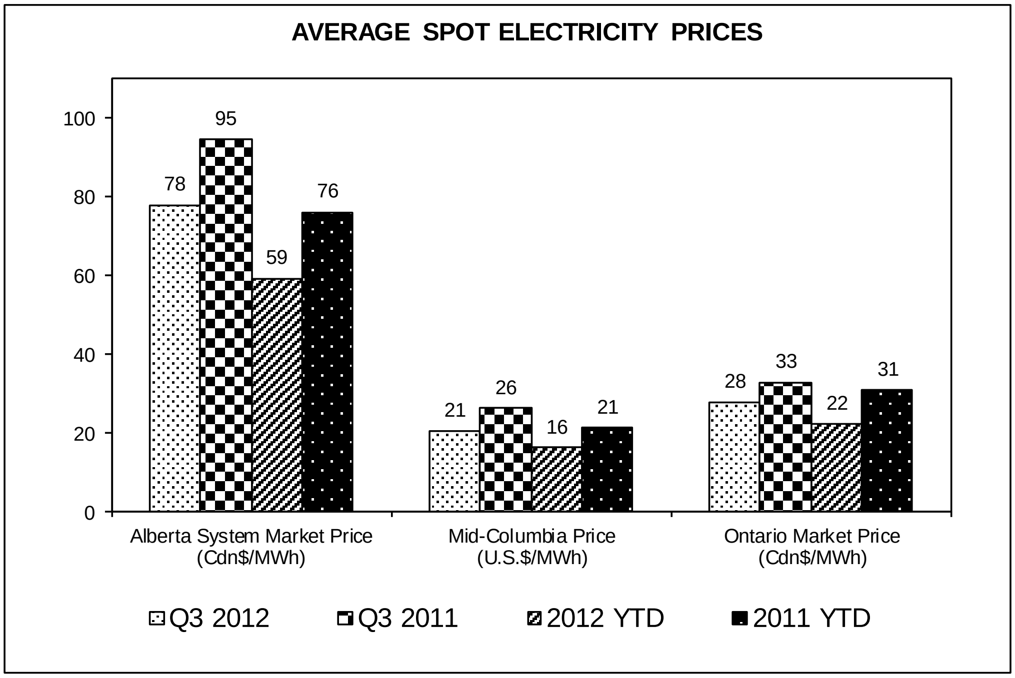
Contracted Cash Flows

During the third quarter of 2012, 90 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also entered into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts for the balance of 2012 ranging from $60 to $65 per megawatt hour ("MWh") in Alberta, and from U.S.$50 to $55 per MWh in the Pacific Northwest. For further information on the contracts related to the Pacific Northwest, please refer to the Non-IFRS Measures section of this MD&A.

Electricity Prices

Please refer to the Business Environment section of our 2011 Annual MD&A for a full discussion of the spot electricity market and the impact of electricity prices on our business, as well as our strategy to hedge our risks associated with changes in these prices.

The average spot electricity prices for the three and nine months ended Sept. 30, 2012 and 2011 in our three major markets are shown in the following graphs.

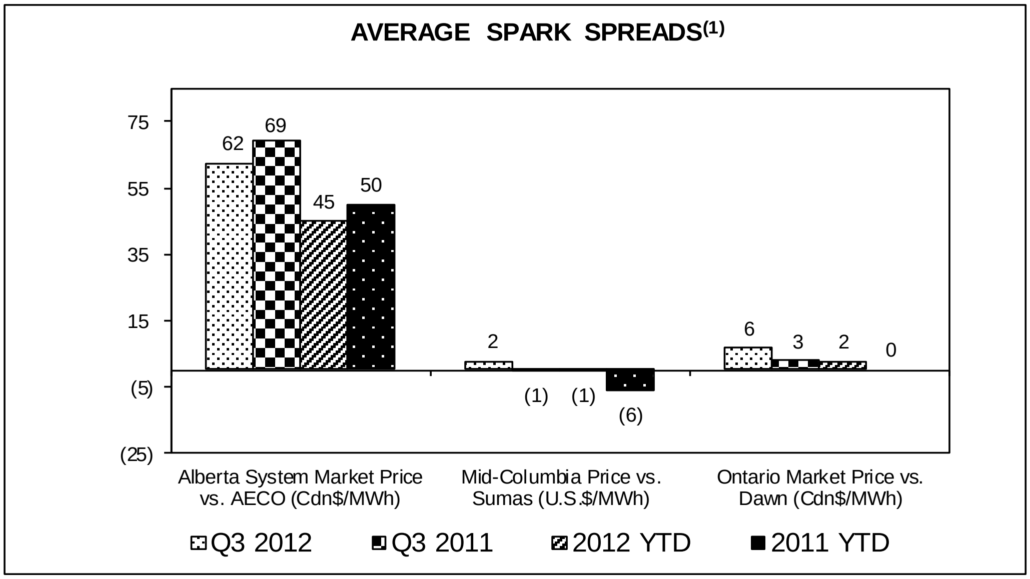


For the three and nine months ended Sept. 30, 2012, average spot prices in Alberta decreased compared to the same periods in 2011 due to lower natural gas prices and lower weather-driven demand. In the Pacific Northwest and Ontario, average spot prices decreased due to lower natural gas prices.

Spark Spreads

Please refer to the Business Environment section of our 2011 Annual MD&A for a full discussion of spark spreads and the impact of spark spreads on our business.

The average spark spreads for the three and nine months ended Sept. 30, 2012 and 2011 in our three major markets are shown in the following graphs.



(1) For a 7,000 Btu/KWh heat rate plant.

For the three and nine months ended Sept. 30, 2012, average spark spreads decreased in Alberta compared to the same periods in 2011 due to lower power prices.

In the Pacific Northwest and Ontario, spark spreads for the three and nine months ended Sept. 30, 2012 increased compared to the same periods in 2011 due to lower natural gas prices.

G E N E R A T I O N : *TransAlta owns and operates hydro, wind, natural gas- and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation revenues and overall profitability are derived from the availability and production of electricity and steam as well as ancillary services such as system support. For a full listing of all of our generating assets and the regions in which they operate, refer to the Plant Summary section of our 2011 Annual MD&A.*

Generation Operations: *At Sept. 30, 2012, our generating assets had 8,213 MW of gross generating capacity(1) in operation (7,870 MW net ownership interest), 83 MW net under construction, and 560 MW under restoration in the Sundance Units 1 and 2 major project. The following information excludes assets that are accounted for as a finance lease or using the equity method, which are discussed separately within this discussion of the Generation Segment.*

The results of Generation Operations are as follows:

	2012				2011	
3 months ended Sept. 30	**Total**	**Comparable adjustments**	**Comparable total(2)**	**Per installed MWh**	Comparable total(2)	Per installed MWh
Revenues	**554**	**60**	**614**	**33.86**	593	32.78
Fuel and purchased power	**208**	**20**	**228**	**12.57**	258	14.26
Gross margin	**346**	**40**	**386**	**21.29**	335	18.52
Operations, maintenance, and administration	**89**	**(2)**	**87**	**4.80**	100	5.53
Depreciation and amortization	**117**	**-**	**117**	**6.45**	111	6.14
Asset impairment charges (reversal)	**(41)**	**41**	**-**	**-**	5	0.28
Inventory writedown (reversal)	**(8)**	**8**	**-**	**-**	-	-
Taxes, other than income taxes	**8**	**-**	**8**	**0.44**	7	0.39
Intersegment cost allocation	**3**	**-**	**3**	**0.17**	2	0.11
Operating income (loss)	**178**	**(7)**	**171**	**9.43**	110	6.07
Installed capacity (GWh)	**18,134**		**18,134**		18,088	
Production (GWh)	**9,562**		**9,562**		9,826	
Availability (%)	**90.5**		**90.5**		83.0	

	2012				2011	
9 months ended Sept. 30	**Total**	**Comparable adjustments**	**Comparable total(2)**	**Per installed MWh**	Comparable total(2)	Per installed MWh
Revenues	**1,611**	**58**	**1,669**	**30.95**	1,740	33.06
Fuel and purchased power	**546**	**20**	**566**	**10.50**	655	12.44
Gross margin	**1,065**	**38**	**1,103**	**20.45**	1,085	20.62
Operations, maintenance and administration	**292**	**(3)**	**289**	**5.36**	304	5.78
Depreciation and amortization	**375**	**-**	**375**	**6.95**	329	6.25
Asset impairment charges	**324**	**(324)**	**-**	**-**	14	0.27
Inventory writedown	**34**	**(25)**	**9**	**0.17**	-	-
Taxes, other than income taxes	**22**	**-**	**22**	**0.41**	21	0.40
Intersegment cost allocation	**10**	**-**	**10**	**0.19**	6	0.11
Operating income (loss)	**8**	**390**	**398**	**7.37**	411	7.81
Installed capacity (GWh)	**53,922**		**53,922**		52,634	
Production (GWh)	**26,327**		**26,327**		27,753	
Availability (%)	**87.7**		**87.7**		82.9	

(1) We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key items) which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated.

(2) Comparable revenues, comparable gross margin, and comparable operating income figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of comparable adjustments.

Generation Operations Production and Comparable Gross Margins[(1)]

Production volumes, comparable revenues[(1)], fuel and purchased power expenses, and comparable gross margins based on geographical regions and fuel types are presented below.

3 months ended Sept. 30, 2012	**Production (GWh)**	**Installed (GWh)**	**Comparable revenues**	**Fuel & purchased power**	**Comparable gross margin**	**Comparable revenues per installed MWh**	**Fuel & purchased power per installed MWh**	**Comparable gross margin per installed MWh**
Coal	**4,985**	**7,110**	**286**	**124**	**162**	**40.23**	**17.44**	**22.79**
Gas	**633**	**786**	**28**	**5**	**23**	**35.62**	**6.36**	**29.26**
Renewables	**1,051**	**2,953**	**67**	**3**	**64**	**22.69**	**1.02**	**21.67**
Total Western Canada	**6,669**	**10,849**	**381**	**132**	**249**	**35.12**	**12.17**	**22.95**
Gas	**1,036**	**1,656**	**86**	**41**	**45**	**51.93**	**24.76**	**27.17**
Renewables	**260**	**1,458**	**25**	**1**	**24**	**17.15**	**0.69**	**16.46**
Total Eastern Canada	**1,296**	**3,114**	**111**	**42**	**69**	**35.65**	**13.49**	**22.16**
Coal	**1,242**	**2,961**	**95**	**46**	**49**	**32.08**	**15.54**	**16.54**
Gas	**355**	**1,210**	**27**	**8**	**19**	**22.31**	**6.61**	**15.70**
Total International	**1,597**	**4,171**	**122**	**54**	**68**	**29.25**	**12.95**	**16.30**
	9,562	**18,134**	**614**	**228**	**386**	**33.86**	**12.57**	**21.29**

3 months ended Sept. 30, 2011	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	5,237	7,022	229	109	120	32.61	15.52	17.09
Gas	500	841	19	6	13	22.59	7.13	15.46
Renewables	827	2,939	54	3	51	18.37	1.02	17.35
Total Western Canada	6,564	10,802	302	118	184	27.96	10.92	17.04
Gas	898	1,656	91	51	40	54.95	30.80	24.15
Renewables	242	1,459	23	1	22	15.76	0.69	15.07
Total Eastern Canada	1,140	3,115	114	52	62	36.60	16.69	19.91
Coal	1,767	2,961	147	79	68	49.65	26.68	22.97
Gas	355	1,210	30	9	21	24.79	7.44	17.35
Total International	2,122	4,171	177	88	89	42.44	21.10	21.34
	9,826	18,088	593	258	335	32.78	14.26	18.52

9 months ended Sept. 30, 2012	**Production (GWh)**	**Installed (GWh)**	**Comparable revenues**	**Fuel & purchased power**	**Comparable gross margin**	**Comparable revenues per installed MWh**	**Fuel & purchased power per installed MWh**	**Comparable gross margin per installed MWh**
Coal	**14,980**	**21,086**	**732**	**311**	**421**	**34.71**	**14.75**	**19.96**
Gas	**1,883**	**2,342**	**80**	**15**	**65**	**34.16**	**6.40**	**27.76**
Renewables	**2,737**	**8,795**	**162**	**9**	**153**	**18.42**	**1.02**	**17.40**
Total Western Canada	**19,600**	**32,223**	**974**	**335**	**639**	**30.23**	**10.40**	**19.83**
Gas	**2,997**	**4,932**	**271**	**121**	**150**	**54.95**	**24.53**	**30.42**
Renewables	**1,055**	**4,344**	**102**	**5**	**97**	**23.48**	**1.15**	**22.33**
Total Eastern Canada	**4,052**	**9,276**	**373**	**126**	**247**	**40.21**	**13.58**	**26.63**
Coal	**1,646**	**8,819**	**240**	**83**	**157**	**27.21**	**9.41**	**17.80**
Gas	**1,029**	**3,604**	**82**	**22**	**60**	**22.75**	**6.10**	**16.65**
Total International	**2,675**	**12,423**	**322**	**105**	**217**	**25.92**	**8.45**	**17.47**
	26,327	**53,922**	**1,669**	**566**	**1,103**	**30.95**	**10.50**	**20.45**

(1) Comparable revenues and comparable gross margin figures are not defined under IFRS. Refer to the Non-IFRS Measures section of this MD&A for further discussion of comparable adjustments.

9 months ended Sept. 30, 2011	Production (GWh)	Installed (GWh)	Comparable revenues	Fuel & purchased power	Comparable gross margin	Comparable revenues per installed MWh	Fuel & purchased power per installed MWh	Comparable gross margin per installed MWh
Coal	16,057	19,824	649	263	386	32.74	13.27	19.47
Gas	1,897	2,496	86	25	61	34.46	10.02	24.44
Renewables	2,422	8,692	155	8	147	17.83	0.92	16.91
Total Western Canada	20,376	31,012	890	296	594	28.70	9.54	19.16
Gas	2,723	4,914	308	172	136	62.68	35.00	27.68
Renewables	1,035	4,331	99	5	94	22.86	1.15	21.71
Total Eastern Canada	3,758	9,245	407	177	230	44.02	19.15	24.87
Coal	2,583	8,786	352	154	198	40.06	17.53	22.53
Gas	1,036	3,591	91	28	63	25.34	7.80	17.54
Total International	3,619	12,377	443	182	261	35.79	14.70	21.09
	27,753	52,634	1,740	655	1,085	33.06	12.44	20.62

Western Canada

Our Western Canada assets consist of coal, natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2011 Annual MD&A for further details on our Western Canadian operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30 (GWh)	**9 months ended Sept. 30 (GWh)**
Production, 2011	6,564	20,376
Higher planned outages at the Alberta coal PPA facilities	(397)	(1,196)
Lower PPA customer demand	(233)	(1,013)
Market curtailments	(184)	(346)
Lower (higher) unplanned outages at Genesee Unit 3	2	(114)
Lower wind volumes	(67)	(19)
Commencement of commercial operations of Keephills Unit 3	180	1,063
Lower unplanned outages at the Alberta coal PPA facilities	345	407
Higher hydro volumes	290	333
Higher production at natural gas-fired facilities	161	74
Higher production due to facility uprates	25	25
Other	(17)	10
Production, 2012	**6,669**	**19,600**

The primary factors contributing to the change in comparable gross margin for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Comparable gross margin, 2011	184	594
Commencement of commercial operations of Keephills Unit 3	15	46
Higher hydro margins	38	40
Lower unplanned outages at the Alberta coal PPA facilities	38	36
Pricing, primarily related to penalties paid and recovered under Alberta coal PPAs	34	31
Higher production due to facility uprates	4	4
Higher planned outages at the Alberta coal PPA facilities	(23)	(55)
Unfavourable coal pricing	(17)	(23)
Market curtailments	(15)	(15)
Higher unplanned outages at Genesee Unit 3	-	(6)
Lower wind volumes	(4)	(2)
Other	(5)	(11)
Comparable gross margin, 2012	**249**	**639**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2011 Annual MD&A for further details on our Eastern Canadian operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30 (GWh)	9 months ended Sept. 30 (GWh)
Production, 2011	1,140	3,758
Favourable market conditions at natural gas-fired facilities	139	274
Higher wind volumes	21	35
Other	(4)	(15)
Production, 2012	**1,296**	**4,052**

The primary factors contributing to the change in gross margin for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Gross margin, 2011	62	230
Favourable contracted gas input costs	5	14
Higher wind volumes	2	2
Other	-	1
Gross margin, 2012	**69**	**247**

International

Our International assets consist of coal, natural gas, and hydro facilities in various locations in the United States, and natural gas and diesel assets in Australia. Refer to the Discussion of Segmented Results section of our 2011 Annual MD&A for further details on our International operations.

The primary factors contributing to the change in production for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30 (GWh)	**9 months ended Sept. 30 (GWh)**
Production, 2011	2,122	3,619
Higher economic dispatching at Centralia Thermal	(1,395)	(3,406)
Lower planned and unplanned outages at Centralia Thermal	871	2,473
Other	(1)	(11)
Production, 2012	**1,597**	**2,675**

The primary factors contributing to the change in comparable gross margin for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30	**9 months ended Sept. 30**
Comparable gross margin, 2011	89	261
Unfavourable pricing, including margins on purchased power	(12)	(43)
Favourable foreign exchange	-	1
Other	(9)	(2)
Comparable gross margin, 2012	**68**	**217**

The outages at Centralia Thermal did not negatively impact our gross margins for the three and nine months ended Sept. 30, 2012 as we were able to extend our planned outage to take advantage of lower market prices to purchase power on the market to fulfill our power contracts. Overall fleet availability, after adjusting for the extended planned outage at Centralia, was 91.7 per cent (Sept. 30, 2011 - 88.3 per cent) and 90.3 per cent (Sept. 30, 2011 - 88.2 per cent) for the three and nine months ended Sept. 30, 2012, respectively.

Operations, Maintenance, and Administration Expense

OM&A expenses for the three and nine months ended Sept. 30, 2012 decreased compared to the same periods in 2011 due to lower costs associated with productivity initiatives and lower compensation costs.

Depreciation and Amortization Expense

The primary factors contributing to the change in depreciation and amortization expense for the three and nine months ended Sept. 30, 2012 are presented below:

	3 months ended Sept. 30	9 months ended Sept. 30
Depreciation and amortization expense, 2011	111	333
Increase in asset base	11	32
Asset retirements	5	18
Unfavourable foreign exchange	-	2
Change in economic life	(6)	(6)
Other	(4)	(4)
Depreciation and amortization expense, 2012	**117**	**375**

Finance Lease

Fort Saskatchewan

Fort Saskatchewan is a natural gas-fired facility with a gross generating capacity of 118 MW in operation, of which TransAlta Cogeneration, L.P. has a 60 per cent ownership interest (35 MW net ownership interest). Key operational information adjusted to reflect our interest in the Fort Saskatchewan facility, which we continue to operate, is summarized below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Availability (%)	**92.1**	92.2	**88.1**	97.3
Production (GWh)	**113**	118	**332**	351

Availability for the three months ended Sept. 30, 2012 was consistent with the same period in 2011.

For the nine months ended Sept. 30, 2012, availability decreased compared to the same period in 2011 due to higher planned outages and seasonal derates due to milder than expected winter temperatures.

Production for the three and nine months ended Sept. 30, 2012 decreased by 5 GWh and 19 GWh, respectively, compared to the same periods in 2011 due to higher planned outages, partially offset by increased customer demand.

Finance lease income for the three and nine months ended Sept. 30, 2012 was consistent with the same periods in 2011 at $1 million and $5 million, respectively.

Please refer to *Note 6* of our audited consolidated financial statements within our 2011 Annual Report for additional information regarding the Fort Saskatchewan finance lease.

Solomon

On Sept. 28, 2012, we announced that we completed the acquisition from Fortescue of its 125 MW natural gas- and diesel-fired Solomon power station in Western Australia for U.S.$318 million. The facility and associated Agreement will be accounted for as a finance lease. The facility is currently under construction and is expected to be commissioned in the fourth quarter of 2012. Please refer to the Significant Events section of this MD&A for additional information.

Equity Investments

Our interests in the CE Gen and Wailuku River Hydroelectric, L.P. joint ventures are accounted for using the equity method and are comprised of geothermal, natural gas, and hydro facilities in various locations throughout the U.S., with 839 MW of gross generating capacity (390 MW net ownership interest). The table below summarizes key operational information adjusted to reflect our interest in these investments:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Availability (%)	**96.8**	98.5	**94.3**	96.4
Production (GWh)				
Gas	**155**	79	**290**	284
Renewables	**325**	345	**921**	962
Total production	**480**	424	**1,211**	1,246

Availability for the three months ended Sept. 30, 2012 decreased compared to the same period in 2011 due to higher unplanned outages.

For the nine months ended Sept. 30, 2012, availability decreased compared to the same period in 2011 due to higher planned and unplanned outages.

Production for the three months ended Sept. 30, 2012 increased compared to the same period in 2011 due to higher customer demand, partially offset by higher unplanned outages.

For the nine months ended Sept. 30, 2012, production decreased compared to the same period in 2011 due to higher planned and unplanned outages, partially offset by higher customer demand.

Equity income for the three months ended Sept. 30, 2012 decreased $14 million due to higher unplanned outages and unfavourable pricing.

For the nine months ended Sept. 30, 2012, equity income decreased $21 million due to higher planned and unplanned outages and unfavourable pricing.

Since 2001, a significant portion of the CE Gen plants have been operating under modified fixed energy price contracts. Commencing May 1, 2012, the terms of the contracts reverted to a pricing clause that permits the power purchaser to pay their short-run avoided costs (“SRAC”) as the price for power. The SRAC is linked to the price of natural gas. There can be no assurances that prices based on the avoided cost of energy after May 1, 2012 will result in revenues equivalent to those realized under the fixed energy price structure.

Please refer to *Note 7* of our audited consolidated financial statements within our 2011 Annual Report and *Note 9* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2012 for additional financial information regarding our investments accounted for using the equity method.

ENERGY TRADING: *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving gross margins, while remaining within Value at Risk ("VaR") limits, is a key measure of Energy Trading's activities. Refer to the Value at Risk and Trading Positions discussion in the Risk Management section of our 2011 Annual MD&A for further discussion on VaR.*

Energy Trading utilizes contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. If the activities are performed on behalf of the Generation Segment, the results of these activities are included in the Generation Segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2011 Annual MD&A.

The results of the Energy Trading Segment, with all trading results presented on a net basis, are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2012	2011	**2012**	2011
Revenues	**(16)**	45	**(10)**	97
Fuel and purchased power	**-**	-	**-**	-
Gross margin	**(16)**	45	**(10)**	97
Operations, maintenance, and administration	**7**	12	**20**	27
Depreciation and amortization	**-**	-	**-**	1
Intersegment cost allocation	**(3)**	(2)	**(10)**	(6)
Operating income (loss)	**(20)**	35	**(20)**	75

For the three months ended Sept. 30, 2012, Energy Trading gross margins decreased compared to the same period in 2011 primarily due to the impact of unexpected weather patterns and unfavourable market expectations on power and gas pricing for trading positions held.

Energy Trading gross margins for the nine months ended Sept. 30, 2012 decreased compared to the same period in 2011 primarily due to gas supply conditions that impacted gas prices, unexpected weather patterns, power plant outages, and the impact of unfavourable market expectations on power and gas pricing for trading positions held.

OM&A expenses for the three and nine months ended Sept. 30, 2012 decreased compared to the same periods in 2011 primarily due to decreased compensation costs.

For the three and nine months ended Sept. 30, 2012, the intersegment cost allocation increased compared to the same periods in 2011 due to additional support costs charged to the Generation Segment.

CORPORATE: *Our Generation and Energy Trading Segments are supported by a Corporate group that provides finance, tax, treasury, legal, regulatory, environmental, health and safety, sustainable development, corporate communications, government and investor relations, information technology, risk management, human resources, internal audit, and other administrative support.*

The expenses incurred by the Corporate Segment are as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Operations, maintenance, and administration	**21**	26	**63**	64
Depreciation and amortization	**5**	4	**15**	15
Operating loss	**26**	30	**78**	79

For the three months ended Sept. 30, 2012, OM&A expenses decreased compared to the same periods in 2011 primarily due to lower compensation costs and lower costs associated with productivity initiatives.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Interest on debt	**54**	57	**168**	167
Capitalized interest	**(1)**	(8)	**(2)**	(31)
Ineffectiveness on fair value hedges	**1**	(1)	**1**	(1)
Other	**(1)**	-	**1**	1
Interest expense	**53**	48	**168**	136
Accretion of provisions	**5**	6	**14**	15
Net interest expense	**58**	54	**182**	151

The change in net interest expense for the three and nine months ended Sept. 30, 2012, compared to the same periods in 2011, is shown below:

	3 months ended Sept. 30	9 months ended Sept. 30
Net interest expense, 2011	54	151
Lower capitalized interest	7	29
(Lower) higher interest rates	(2)	3
Unfavourable foreign exchange impacts	-	1
Ineffectiveness on fair value hedges	2	2
(Lower) higher financing costs	(2)	1
Higher interest income	-	(1)
Lower decommissioning and restoration accretion	(1)	(1)
Lower debt levels	-	(3)
Net interest expense, 2012	**58**	**182**

INCOME TAXES

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Earnings (loss) before income taxes	**85**	70	**(514)**	399
Income attributable to non-controlling interests	**(7)**	(7)	**(25)**	(27)
Equity income (loss)	**-**	(14)	**5**	(16)
Impacts associated with certain de-designated and ineffective hedges	**60**	9	**58**	(125)
Asset impairment charges (reversal)	**(41)**	5	**324**	14
Inventory writedown	**(28)**	-	**5**	**-**
Gain on sale of facilities	**-**	-	**(3)**	(3)
Sundance Units 1 and 2 arbitration	**7**	-	**254**	-
Gain on sale of collateral	**(15)**	-	**(15)**	-
Other non-comparable items	**2**	-	**3**	9
Earnings (loss) attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**63**	63	**92**	251
Income tax expense	**14**	9	**92**	95
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**21**	2	**20**	(45)
Income tax (expense) recovery related to asset impairment charges	**(10)**	1	**(5)**	3
Income tax recovery (expense) related to inventory writedown	**(10)**	**-**	**2**	**-**
Income tax expense related to gain on sale of facilities	**-**	-	**(1)**	(1)
Income tax recovery related to Sundance Units 1 and 2 arbitration	**2**	-	**65**	-
Income tax rexpense related to gain on sale of collateral	**(4)**	-	**(4)**	-
Income tax expense related to writeoff of deferred income tax assets	**-**	-	**(169)**	-
Income tax expense related to changes in corporate income tax rates	**-**	-	**(8)**	-
Income tax recovery related to the resolution of certain outstanding tax matters		-	**9**	-
Income tax recovery related to other non-comparable items	**1**	-	**1**	3
Income tax expense excluding non-comparable items	**14**	12	**2**	55
Effective tax rate on earnings (loss) attributable to TransAlta shareholders excluding non-comparable items (%)	**22**	19	**2**	22

The income tax expense excluding non-comparable items for the three months ended Sept. 30, 2012 increased compared to the same period in 2011 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The income tax expense excluding non-comparable items for the nine months ended Sept. 30, 2012 decreased compared to the same period in 2011 due to lower comparable earnings, changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, and the positive resolution of certain outstanding tax matters.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three months ended Sept. 30, 2012 increased compared to the same period in 2011 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the nine months ended Sept. 30, 2012 decreased compared to the same period in 2011 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, the effect of certain deductions that do not fluctuate with earnings, and the positive resolution of certain outstanding tax matters.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three and nine months ended Sept. 30, 2012 was comparable to the same periods in 2011.

FINANCIAL POSITION

The following chart highlights significant changes in the Condensed Consolidated Statements of Financial Position from Dec. 31, 2011 to Sept. 30, 2012:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	22	Timing of receipts and payments
Accounts receivable	21	Timing of customer receipts
Collateral paid	(29)	Decreased collateral requirements associated with changes in forward prices
Inventory	13	Higher average coal costs partially offset by writedown of coal inventory
Investments	(15)	Equity loss and unfavourable foreign exchange
Long-term receivable	(18)	Sale of collateral on hand at MF Global Inc.
Finance lease receivable	305	Acquisition of Solomon power station
Property, plant, and equipment, net	(305)	Asset impairments and depreciation partially offset by additions
Deferred income tax assets	(121)	Writeoff of deferred income tax assets related to profitability of U.S. operations
Risk management assets (current and long-term)	(200)	Price movements and changes in underlying positions
Accounts payable and accrued liabilities	(37)	Timing of payments and lower capital accruals
Collateral received	(12)	Reduction in collateral received from counterparties associated with changes in forward prices
Income taxes payable	(15)	Increase in instalment payments
Long-term debt (including current portion)	130	Increased borrowings under credit facilities partially offset by repayments
Decommissioning and other provisions (current and long-term)	(48)	Decrease in decommissioning and commercial provisions, including the Sundance Units 1 and 2 arbitration impacts
Deferred credits and other long-term liabilities	28	Increase in defined benefit accrual
Deferred income tax liabilities	(54)	Positive resolution of certain tax matters and the Sundance Units 1 and 2 arbitration impacts
Risk management liabilities (current and long-term)	(17)	Price movements and changes in underlying positions
Equity attributable to shareholders	(267)	Net loss for the period and share dividends, partially offset by issuance of common and preferred shares
Non-controlling interests	(23)	Distributions to non-controlling interests net of non-controlling interests' portion of net earnings

FINANCIAL INSTRUMENTS

Refer to *Note 13* of the notes to the consolidated financial statements within our 2011 Annual Report and *Note 12* of our interim condensed consolidated financial statements as at and for the three and nine months ended Sept. 30, 2012 for details on Financial Instruments. Refer to the Risk Management section of our 2011 Annual Report and *Note 13* of our interim condensed consolidated financial statements for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2011.

Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under IFRS as Level III financial instruments. Level III financial instruments are not traded in an active market and fair value is, therefore, developed using valuation models based upon internally developed assumptions or inputs. Our Level III fair values are determined using data such as unit availability, transmission congestion, or demand profiles. Fair values are validated on a quarterly basis by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements.

We also have various contracts with terms that extend beyond five years. As forward price forecasts are not available for the full period of these contracts, the value of these contracts must be derived by reference to a forecast that is based on a combination of external and internal fundamental modeling, including discounting. As a result, these contracts are classified in Level III. These contracts are for specified prices with counterparties that we believe to be creditworthy.

At Sept. 30, 2012, total Level III financial instruments had a net asset carrying value of $32 million (Dec. 31, 2011 - $7 million net liability).

During the three and nine months ended Sept. 30, 2012, unrealized pre-tax gains of nil (Sept. 30, 2011 - $3 million gain) and $75 million (Sept. 30, 2011 - $207 million gain), respectively, related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in earnings. The cash flow hedges were in respect of future power production expected to occur during 2011 and into 2012. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using current forward prices which will change between now and the time the contracts will be settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings in the period in which they settle, the majority of which will occur during 2012. As these gains have already been recognized in earnings in the current and prior periods, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

In addition, during 2012, we discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at Sept. 30, 2012, cumulative gains of $14 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur.

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Condensed Consolidated Statements of Cash Flows for the three and nine months ended Sept. 30, 2012 compared to the same periods in 2011:

3 months ended Sept. 30	**2012**	2011	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**61**	38	
Provided by (used in):			
Operating activities	**14**	212	Unfavourable changes in working capital of $262 million partially offset by higher cash earnings of $64 million
Investing activities	**(483)**	(182)	Acquisition of finance lease for $312 million and an increase in additions to PP&E and intangibles of $50 million, partially offset by a net positive cash impact of $48 million related to changes in collateral received from or paid to counterparties
Financing activities	**478**	(2)	Issuance of common shares for $292 million and preferred shares for $217 million, increased borrowings under credit facilities, and a decrease in common share cash dividends of $30 million due to dividends reinvested through the dividend reinvestment plan, partially offset by an increase in debt repayments and an increase in preferred share dividends of $3 million
Translation of foreign currency cash	**1**	-	
Cash and cash equivalents, end of period	**71**	66	

9 months ended Sept. 30	**2012**	2011	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**49**	35	
Provided by (used in):			
Operating activities	**275**	503	Lower cash earnings of $49 million and unfavourable changes in working capital of $179 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration
Investing activities	**(822)**	(400)	Acquisition of finance lease for $312 million, an increase in additions to PP&E and intangibles of $178 million and a decrease in proceeds on sale of facilities of $27 million, partially offset by a net positive impact of $119 million related to changes in collateral received from or paid to counterparties
Financing activities	**568**	(73)	Issuance of common shares for $293 million and preferred shares for $217 million, increased borrowings under credit facilities, and a decrease in common share cash dividends of $57 million due to dividends reinvested through the dividend reinvestment plan, partially offset by an increase in debt repayments and an increase in preferred share dividends of $10 million
Translation of foreign currency cash	**1**	1	
Cash and cash equivalents, end of period	**71**	66	

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk arises from our ability to meet general funding needs, engage in trading and hedging activities, and manage the assets, liabilities and capital structure of the Corporation. Liquidity risk is managed by maintaining sufficient liquid financial resources to fund obligations as they come due in the most cost-effective manner.

Our liquidity needs are met through a variety of sources, including cash generated from operations, borrowings under our long-term credit facilities, long-term debt and equity issued under our Canadian and U.S. shelf registrations, and our dividend reinvestment program. Our primary uses of funds are operational expenses, capital expenditures, dividends, distributions to non-controlling limited partners, and interest and principal payments on debt securities.

Debt

Long-term debt totalled $4.2 billion at Sept. 30, 2012 and $4.0 billion at Dec. 31, 2011. Total long-term debt increased from Dec. 31, 2011 primarily due to higher borrowings under our credit facilities, partially offset by favourable changes in foreign exchange rates.

Credit Facilities

At Sept. 30, 2012, we have a total of $2.4 billion (Dec. 31, 2011 - $2.0 billion) of committed credit facilities of which $0.8 billion (Dec. 31, 2011 - $0.9 billion) is not drawn and is available, subject to customary borrowing conditions. At Sept. 30, 2012, the $1.6 billion (Dec. 31, 2011 - $1.1 billion) of credit utilized under these facilities is comprised of actual drawings of $1.3 billion (Dec. 31, 2011 - $0.8 billion) and of letters of credit of $0.3 billion (Dec. 31, 2011 - $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, with the remainder comprised of bilateral credit facilities which mature between the third and fourth quarters of 2013. We anticipate renewing these facilities as required, based on reasonable commercial terms, prior to their maturities. In April 2012, we completed a renewal of our $1.5 billion committed syndicated bank facility, and extended the maturity from 2015 to 2016.

In addition to the $0.8 billion available under the credit facilities, we also have $46 million of cash available.

Share Capital

On Oct. 25, 2012, we had 254.7 million common shares outstanding, 12.0 million Series A, 11.0 million Series C, and 9.0 million Series E first preferred shares outstanding. At Sept. 30, 2012, we had 251.1 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. At Sept. 30, 2012, we also had 12.0 million (Dec. 31, 2011 - 12.0 million) Series A, 11.0 million (Dec. 31, 2011 - 11.0 million) Series C, and 9.0 million Series E (Dec. 31, 2011 - nil) first preferred shares issued and outstanding.

We issue common shares for cash proceeds, on exercise of stock options and other share-based payment plans, or for reinvestment of dividends. During February 2012, we added a Premium Dividend™ component to the Plan. Please refer to the Subsequent Events section of our 2011 Annual Report for additional information regarding the amendments.

During the three months ended Sept. 30, 2012, 24.1 million (Sept. 30, 2011 - 0.9 million) common shares were issued for $342 million (Sept. 30, 2011 - $17 million). In September 2012, we issued 21.2 million common shares through a public offering and related underwriters' over-allotment option for total net proceeds of $295 million. In addition, 2.9 million (Sept. 30, 2011 - 0.8 million) common shares were issued for $48 million (Sept. 30, 2011 - $17 million) for dividends reinvested under the terms of the Plan and a nominal number (Sept. 30, 2011 - a nominal number) were issued for a nominal amount (Sept. 30, 2011 - a nominal amount). During the nine months ended Sept. 30, 2012, 27.5 million (Sept. 30, 2011 - 2.5 million) common shares were issued for $407 million (Sept. 30, 2011 - $51 million). In addition to the public offering, 6.2 million (Sept. 30, 2011 - 2.5 million) common shares were issued for $110 million (Sept. 30, 2011 - $49 million) for dividends reinvested under the terms of the Plan and 0.1 million (Sept. 30, 2011 - 0.1 million) common shares were issued other proceeds of $2 million (Sept. 30, 2011 - $2 million).

We employ a variety of share-based payment plans to align employee and corporate objectives. During the nine months ended Sept. 30, 2012, a nominal number of employee stock options were exercised, expired or were cancelled (Sept. 30, 2011 - 0.5 million). During the nine months ended Sept. 30, 2012, 1.4 million (Sept. 30, 2011 - 1.5 million) Performance Share Ownership Plan units were granted and a nominal number (Sept. 30, 2011 - nil) were awarded and exchanged for common shares.

On Aug. 10, 2012, we completed a public offering of 9.0 million Series E Cumulative Redeemable Rate Reset First Preferred Shares for gross proceeds of $225 million.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At Sept. 30, 2012, we provided letters of credit totalling $316 million (Dec. 31, 2011 - $328 million) and cash collateral of $16 million (Dec. 31, 2011 - $45 million). These letters of credit and cash collateral secure certain amounts included on our Condensed Consolidated Statements of Financial Positions under "Risk Management Liabilities" and "Decommissioning and Other Provisions".

CLIMATE CHANGE AND THE ENVIRONMENT

On Sept. 11, 2012, the Canadian federal Government published the final regulations governing greenhouse gas ("GHG") emissions from coal-fired power plants, to become effective on July 1, 2015. The regulations provide for 50 years of life for coal units, at which point units must meet an emissions performance standard of approximately 420 tonnes per GWh. There are some exceptions that require older units commissioned before 1975 to reach end of life by Dec. 31, 2019, and units commissioned between 1975 and 1986 to reach end of life by Dec. 31, 2029. Compared to the initial draft version of these regulations, the final regulation provides additional operating time and increased flexibility for our Canadian coal units, allowing for a smoother transition of those units in a more cost-effective manner.

In addition, in Alberta there are requirements for coal-fired generation units to implement additional air emission controls for oxides of nitrogen ("NOx"), sulphur dioxide ("SO_2"), and particulate matter, once they reach the end of their PPAs, in most cases at 2020. These regulatory requirements were developed by the province in 2004 as a result of multi-stakeholder discussions under Alberta's Clean Air Strategic Alliance ("CASA"). However, the release of the federal GHG regulations creates a misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates. We are in discussions with the provincial government to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply.

On March 27, 2012, the U.S. Environmental Protection Agency ("EPA") proposed GHG emission standards for future coal-fired power plants. It is intended that the proposed standard would be met with fuel switching or clean coal technologies. As this regulatory framework is for new coal-fired plants, we expect no material impact on our existing coal units at Centralia.

In December 2011, the EPA issued national standards for mercury emissions from power plants. Existing sources will have up to four years to comply. We have already voluntarily installed mercury capture technology at our Centralia coal-fired plant, and began full capture operations in early 2012. We are also installing additional technology to further reduce NOx, consistent with the Washington State Bill passed in April 2011 requiring TransAlta to begin operating such technology by Jan. 1, 2013.

We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Alberta Thermal operations in 2010 in order to meet the province's 70 per cent reduction objectives. Our new Keephills Unit 3 plant began operations in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as SO_2 capture and low NOx combustion technology, which is consistent with the technology that is currently in use at Genesee Unit 3. Uprate projects at our Keephills and Sundance plants will improve the energy and emissions efficiency of those units.

2012 OUTLOOK

Business Environment

Power Prices

For the remainder of 2012, our expectation is that power prices in Alberta will be lower compared to the same period last year primarily driven by lower natural gas prices, partially offset by continued load growth. The potential for higher prices exists and are expected to be the result of weather-driven demand and the frequency of unplanned outages. In the Pacific Northwest, we continue to expect weak prices due to historically low natural gas prices, weak load growth, and the addition of wind assets.

Environmental Legislation

The finalization of the federal Canadian GHG regulations for coal-fired power has initiated further activities. It is anticipated that the Government of Alberta will subsequently develop an equivalency agreement with the federal government to allow provincial jurisdiction and management of equivalent emissions targets. This may provide additional flexibility to coal-fired generators in meeting the regulatory requirements.

In addition, there are ongoing discussions between the federal and provincial governments regarding a national Air Quality Management System for air pollutants. In Alberta's recently released Clean Air Strategy, the province indicated that its provincial air quality management system will operationalize any national system.

In the U.S., it is not yet clear how climate change legislation for existing fossil-fuel-based generation will unfold. Additionally, new air pollutant regulations for the power sector are anticipated, but will not directly affect our coal-fired operations in Washington State. TransAlta's agreement with Washington State, established in April 2011, provides regulatory clarity at the state level regarding an emissions regime related to the Centralia Coal plant until 2025.

The California Air Resource Board has not finalized its rules regarding resource shuffling of imported power, but electricity imports into California from Centralia Generation and our proprietary trading will begin to incur a liability under California's Cap and Trade Program Jan. 1, 2013. TransAlta and other entities are meeting with regulators to advocate for regulatory clarity on issues such as resource shuffling. The annual impact of compliance will be dependent on actual electricity imports into California, the established fee rate, final regulations on resource shuffling, and our trading within the cap and trade program.

We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

The siting, construction, and operation of electrical energy facilities requires interaction with many stakeholders. Recently, certain stakeholders have brought actions against government agencies and owners over alleged adverse impacts of wind projects. We are monitoring these claims in order to assess the risk associated with these activities.

Economic Environment

The economic environment showed signs of weakness during 2012 and we expect slow to moderate growth in Alberta and Australia through the remainder of the year, and weak growth in other markets. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no material counterparty losses in the third quarter of 2012, and we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to be constant for the remainder of 2012. Although the uprate at Sundance Unit 3 will be completed in the fourth quarter of 2012, the increased capacity resulting from the uprate will not be realized until we replace the generator stator. Overall production is expected to increase for the remainder of 2012 due to lower planned outages. Overall availability in 2012 is expected to increase for the remainder of 2012 due to lower planned and unplanned outages, and is expected to be in the range of 89 to 90 per cent.

Contracted Cash Flows

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average, approximately 75 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis, we target being up to 90 per cent contracted for the upcoming year. As at the end of the third quarter, approximately 90 per cent of our 2012 capacity was contracted. The average price of our short-term physical and financial contracts for the balance of 2012 ranges from $60 to $65 per MWh in Alberta, and from U.S.$50 to U.S.$55 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2012, on a standard cost basis, are expected to increase by approximately 15 per cent compared to 2011 due to the drivers mentioned above and lower coal production volumes driven by lower plant production.

Although we own the Centralia mine in the State of Washington, it is not currently operational. Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2012 is expected to increase by approximately four per cent due to higher diesel and commodity costs, and coal dust mitigation expenses.

The value of coal inventories are assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges will be recognized in net earnings. For more information on the inventory impairment charges and reversals recorded in 2012, please refer to the Significant Events section of this MD&A.

We purchase natural gas from outside companies coincident with production or have it supplied by our customers, thereby minimizing our risk to changes in prices. The continued success of unconventional gas production in North America could reduce the year to year volatility of prices in the near term.

During the third quarter of 2012, we entered into several agreements for the purchase of natural gas to meet fuel requirements and related transportation for the balance of 2012 and 2013. The future payments are estimated to be $5 million for 2012 and $43 million for 2013.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Operations, Maintenance, and Administration Costs

OM&A costs for 2012 are expected to be approximately five per cent lower than 2011 OM&A.

Energy Trading

Earnings from our Energy Trading Segment are affected by prices in the market, overall strategies adopted, and changes in legislation. We continuously monitor both the market and our exposure, to maximize earnings while still maintaining an acceptable risk profile. Our outlook is for Energy Trading to contribute up to $20 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar, Euro, and Australian dollar, by offsetting foreign denominated assets with foreign denominated liabilities and by entering into foreign exchange contracts. We also have foreign denominated expenses, including interest charges, which largely offset our net foreign denominated earnings.

Net Interest Expense

Net interest expense for 2012 is expected to be higher than our reported 2011 net interest expense mainly due to lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the U.S. dollar will affect the amount of net interest expense incurred.

Liquidity and Capital Resources

If there is increased volatility in power and natural gas markets, or if market trading activities increase, we may need additional liquidity in the future. We expect to maintain adequate available liquidity under our committed credit facilities.

Accounting Estimates

A number of our accounting estimates, including those outlined in in the Critical Accounting Policies and Estimates section of our 2011 Annual MD&A, are based on the current economic environment and outlook. As a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities and asset valuation for our asset impairment calculations.

Income Taxes

The effective tax rate on earnings excluding non-comparable items for 2012 is expected to be approximately 10 to 15 per cent, which is lower than the statutory tax rate due to certain income tax recoveries which are not impacted by earnings. If certain income tax recoveries which are not impacted by earnings are excluded, the effective tax rate on earnings excluding non-comparable items for 2012 is expected to be approximately 23 to 28 per cent.

Capital Expenditures

Our major projects are focused on sustaining our current operations and supporting our growth strategy.

Growth and Major Project Expenditures

We have two significant growth capital projects that are currently in progress with targeted completion dates of Q4 2012 and Q1 2013 and one additional major project with a targeted completion date of Q4 2013. A summary of each of these items is outlined below:

	Total Project		2012			
	Estimated spend	**Spent to date(1)**	**Estimated spend**	**Spent to date(1)**	**Target completion date**	**Details**
Growth						
Keephills Unit 1 uprate	25	25	10 - 20	12	Commercial operations began Q2 2012	An expected 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	26	25	10 - 20	15	Commercial operations began Q2 2012	A 17 MW efficiency uprate at our Keephills facility
Sundance Unit 3 uprate(2)	27	18	15 - 20	7	Q4 2012	An expected 15 MW efficiency uprate at our Sundance facility
New Richmond(3)	205	125	165 - 185	96	Q1 2013	A 68 MW wind farm in Quebec
Total growth	**283**	**193**	**200 - 245**	**130**		
Major Projects						
Sundance Units 1 and 2	190	10	35 - 55	10	Q4 2013	Sundance Units 1 and 2 comprising 560 MW of our Sundance power plant
Total major projects and growth	**473**	**203**	**235 - 300**	**140**		

During the third quarter 2012, we entered into an agreement with Alstom Power & Transport Canada Inc. for the manufacture, delivery and erection of the Sundance Units 1 and 2 waterwalls. The total fixed price commitment under the contract is $79 million, with $24 million expected to be incurred in 2012 and $55 million in 2013. Payments will be made as agreed milestones are achieved. Additional costs to be paid under the contract include reimbursable items, such as direct labour, subcontractors, and labour incentive allowances.

(1) Represents amounts spent as of Sept. 30, 2012. In 2012, we also spent a combined $2 million on facilities that had previously commenced operations. During the second quarter, we transferred $1 million from growth capital projects to sustaining capital expenditures for capital spares.

(2) Although the uprate is expected to be completed in Q4 2012, the increased capacity resulting from the uprate will not be realized until we replace the generator stator.

(3) New Richmond total project costs spent to date include expenditures of $5 million which were included in project development costs in 2011.

Transmission

For the three and nine months ended Sept. 30, 2012, a total of $1 million and $3 million, respectively, was spent on transmission projects. The estimated spend for 2012 for transmission projects is $8 million. Transmission projects consist of the major maintenance and reconfiguration of the transmission networks of Alberta to increase capacity of power flow in the lines.

Sustaining Capital and Productivity Expenditures

For 2012, our estimate for total sustaining capital and productivity expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Spent to date(1)
Routine capital	Expenditures to maintain our existing generating capacity	100 - 115	80
Productivity capital	Projects to improve power production efficiency	50 - 70	41
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	40 - 50	29
Planned major maintenance	Regularly scheduled major maintenance	265 - 285	218
Total sustaining and productivity expenditures		**455 - 520**	**368**

Our planned major maintenance program relates to regularly scheduled major maintenance activities and includes costs related to inspection, repair and maintenance, and replacement of existing components. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred. Details of the 2012 planned major maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2012	Spent to date(1)
Capitalized	215 - 230	50 - 55	265 - 285	218
Expensed	-	0 - 5	0 - 5	-
	215 - 230	50 - 60	265 - 290	218

	Coal	Gas and Renewables	Expected total	Lost to date
GWh lost	3,820 - 3,830	245 - 255	4,065 - 4,085	3,531

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, reinvested dividends under the Plan, and capital markets. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be impacted by the current economic environment due to the highly contracted nature of our cash flows, our financial position, and the amount of capital available to us under existing committed credit facilities.

(1) Represents amounts incurred as of Sept. 30, 2012.

FUTURE ACCOUNTING CHANGES

In June 2012, the International Accounting Standards Board ("IASB") issued *Consolidated Financial Statements, Joint Arrangements and Disclosure of Interests in Other Entities: Transition Guidance (Amendments to IFRS 10, IFRS 11 and IFRS 12)*. The amendments clarify the transition guidance in IFRS 10 and provide additional transition relief for all three standards by limiting the requirement to provide adjusted comparative information to only the preceding comparative period. The amendments are effective for annual periods beginning on or after Jan. 1, 2013. We will apply these amendments along with the adoption of IFRS 10, 11 and 12 on Jan. 1, 2013.

For a summary of additional new or amended accounting standards that have been previously issued by the IASB but are not yet effective and not yet applied please refer to the Future Accounting Changes section of our 2011 annual MD&A.

ADDITIONAL IFRS MEASURES

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled "gross margin" and "operating income (loss)" in our Condensed Consolidated Statements of Earnings for the three and nine months ended Sept. 30, 2012 and 2011. Presenting these line items provides management and investors with a measurement of ongoing operating performance which is readily comparable from period to period.

NON-IFRS MEASURES

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Presenting earnings on a comparable basis, comparable gross margin, and comparable operating income from period to period provides management and investors with supplemental information to evaluate earnings trends in comparison with results from prior periods. In calculating these items, we exclude the impact related to certain hedges that are either de-designated or deemed ineffective for accounting purposes, as management believes that these transactions are not representative of our business operations. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings in the period in which they settle. As these gains have already been recognized in earnings in current or prior periods, future reported earnings will be lower, however, the expected cash flows from these contracts will not change. In calculating comparable earnings measures we have also excluded, as applicable, the inventory writedown, as the recognition of the writedown is related to the hedges that were de-designated or deemed ineffective during prior quarters. The effect of the inventory impairment will be recognized in comparable earnings over the balance of the year as the inventory is consumed. We have also excluded certain impacts to revenue associated with Sundance Units 1 and 2, asset impairment charges, the writeoff of deferred income tax assets, the income tax expense related to changes in corporate income tax rates, the income tax recovery related to the resolution of certain tax matters, the gain on sale of facilities, the writeoff of Project Pioneer costs, the gain on sale of collateral, the writeoff of wind development costs, and the writedown of certain capital spares, as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

Net Earnings (Loss) on a Comparable Basis

Net earnings (loss) on a comparable basis are reconciled to net earnings (loss) attributable to common shareholders below:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Net earnings (loss) attributable to common shareholders	**56**	50	**(652)**	266
Impacts associated with certain de-designated and ineffective hedges, net of tax	**39**	7	**38**	(80)
Asset impairment charges (reversal), net of tax	**(31)**	4	**329**	11
Inventory writedown, net of tax	**(18)**	-	**3**	-
Sundance Units 1 and 2 arbitration, net of tax	**5**	-	**189**	-
Income tax expense related to writeoff of deferred income tax assets	**-**	-	**169**	-
Income tax expense related to changes in corporate income tax rates	**-**	-	**8**	-
Income tax recovery related to the resolution of certain tax matters	**-**	-	**(9)**	-
Gain on sale of facilities, net of tax	**-**	-	**(2)**	(2)
Writeoff of Project Pioneer costs, net of tax	**1**	-	**2**	-
Gain on sale of collateral, net of tax	**(11)**	-	**(11)**	-
Writeoff of wind development costs, net of tax	**-**	-	**-**	3
Writedown of capital spares, net of tax	**-**	-	**-**	3
Net earnings on a comparable basis	**41**	61	**64**	201
Weighted average number of common shares outstanding in the period	**234**	223	**229**	222
Net earnings on a comparable basis per share	**0.18**	0.27	**0.28**	0.91

Comparable Gross Margin

Comparable gross margin is calculated as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Gross margin(1)	**330**	371	**1,055**	1,307
Impacts associated with certain de-designated and ineffective hedges	**60**	9	**58**	(125)
Impacts to revenue associated with Sundance Units 1 and 2(2)	**-**	(9)	**(20)**	(32)
Inventory writedown	**(20)**	-	**(20)**	-
Comparable gross margin	**370**	371	**1,073**	1,150

(1) These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of this item.

(2) The results have been adjusted retroactively for the impact of Sundance Units 1 and 2. Comparative figures have also been adjusted in this table only to provide period over period comparability.

Comparable Operating Income

A reconciliation of comparable operating income is as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Operating income (loss)[1]	**132**	106	**(90)**	523
Impacts associated with certain de-designated and ineffective hedges	**60**	9	**58**	(125)
Asset impairment charges (reversal)	**(41)**	5	**324**	14
Inventory writedown	**(28)**	-	**5**	-
Writeoff of Project Pioneer costs	**2**	-	**3**	-
Writeoff of wind development costs	**-**	-	**-**	5
Writedown of capital spares	**-**	-	**-**	4
Comparable operating income	**125**	120	**300**	421

Comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA")

Presenting comparable EBITDA from period to period provides management and investors with a proxy for the amount of cash generated from operating activities before net interest expense, non-controlling interests, income taxes, and working capital adjustments.

A reconciliation of comparable EBITDA to operating income is as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2012	2011	**2012**	2011
Operating income (loss)[1]	**132**	106	**(90)**	523
Asset impairment charges (reversal)	**(41)**	5	**324**	14
Inventory writedown	**(28)**	-	**5**	-
Depreciation and amortization per the Consolidated Statements of Cash Flows[2]	**129**	126	**419**	383
Impacts associated with certain de-designated and ineffective hedges	**60**	9	**58**	(125)
Impacts to revenue associated with Sundance Units 1 and 2[3]	**-**	(9)	**(20)**	(32)
Writeoff of Project Pioneer costs	**2**	-	**3**	-
Writeoff of wind development costs	**-**	-	**-**	5
Writedown of capital spares	**-**	-	**-**	4
Comparable EBITDA	**254**	237	**699**	772

(1) These items are Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of this item.

(2) To calculate comparable EBITDA, we use depreciation and amortization per the Condensed Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in fuel and purchased power on the Condensed Consolidated Statements of Earnings.

(3) The results have been adjusted retroactively for the impact of Sundance Units 1 and 2. Comparative figures have also been adjusted in this table only to provide period over period comparability.

Funds From Operations and Funds From Operations per Share

Presenting funds from operations and funds from operations per share from period to period provides management and investors with a proxy for the amount of cash generated from operating activities, before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Funds from operations per share is calculated as follows using the weighted average number of common shares outstanding during the period:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2012	2011	**2012**	2011
Cash flow from operating activites	**14**	212	**275**	503
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	**204**	-
Change in non-cash operating working capital balances	**218**	(44)	**92**	117
Funds from operations	**232**	168	**571**	620
Weighted average number of common shares outstanding in the period	**234**	223	**229**	222
Funds from operations per share	**0.99**	0.75	**2.49**	2.79

Free Cash Flow (Deficiency)

Free cash flow (deficiency) represents the amount of cash generated from operations by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments of debt, pay additional common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort free cash flow (deficiency) with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects.

Sustaining capital and productivity expenditures for the three months ended Sept. 30, 2012 represents total additions to property, plant, and equipment and intangibles per the Condensed Consolidated Statements of Cash Flows less $62 million that we have invested in projects and growth. For the same period in 2011, we invested $20 million ($19 million net of joint venture contributions) in projects and growth. For the nine months ended Sept. 30, 2012 and 2011, we invested $144 million and $88 million ($87 million net of joint venture contributions), respectively, in projects and growth.

The reconciliation between cash flow from operating activities and free cash flow (deficiency) is outlined below:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2012	2011	**2012**	2011
Cash flow from operating activities	**14**	212	**275**	503
Add (deduct):				
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**-**	-	**204**	-
Changes in non-cash operating working capital	**218**	(44)	**92**	117
Sustaining capital and productivity expenditures	**(120)**	(112)	**(368)**	(246)
Dividends paid on common shares[(1)]	**(18)**	(48)	**(86)**	(143)
Dividends paid on preferred shares	**(7)**	(4)	**(21)**	(11)
Distributions paid to subsidiaries' non-controlling interests	**(9)**	(9)	**(42)**	(44)
Free cash flow (deficiency)	**78**	(5)	**54**	176

(1) Net of dividends reinvested under the Plan.

We seek to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to our business.

SELECTED QUARTERLY INFORMATION

	Q4 2011	Q1 2012	Q2 2012	**Q3 2012**
Revenue	701	656	407	**538**
Net earnings (loss) attributable to common shareholders	24	89	(797)	**56**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.11	0.40	(3.51)	**0.24**
Comparable earnings (loss) per share	0.13	0.20	(0.10)	**0.18**

	Q4 2010	Q1 2011	Q2 2011	Q3 2011
Revenue	779	818	515	629
Net earnings attributable to common shareholders	92	204	12	50
Net earnings per share attributable to common shareholders, basic and diluted	0.42	0.92	0.05	0.22
Comparable earnings per share	0.36	0.34	0.29	0.27

Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.

DISCLOSURE CONTROLS AND PROCEDURES

As required by Rule 13a-15 under the *Securities Exchange Act of 1934* ("Exchange Act"), management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Sept. 30, 2012, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

FORWARD LOOKING STATEMENTS

This MD&A, the documents incorporated herein by reference, and other reports and filings made with the securities regulatory authorities, include forward looking statements. All forward looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected further developments, and other factors deemed appropriate in the circumstances. Forward looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "anticipate", "intend", "plan", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance and are subject to risks, uncertainties and other important factors that could cause our actual performance to be materially different from that projected.

In particular, this MD&A contains forward looking statements pertaining to the following: expectations relating to the timing of the completion and commissioning of projects under development, including uprates and major projects, and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend, and maintenance, and the variability of those costs; the impact of certain hedges on future reported earnings and cash flows; expectations related to future earnings and cash flow from operating and contracting activities; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expected impacts of load growth and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation and their expected impact on us, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; expectations for the outcome of existing or potential contractual claims; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the U.S. dollar; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment; our credit practices; and the estimated contribution of Energy Trading activities to gross margin.

Factors that may adversely impact our forward looking statements include risks relating to: fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; the regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural disasters; the threat of domestic terrorism and cyber-attacks; equipment failure; energy trading risks; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing; structural subordination of securities; counterparty credit risk; insurance coverage; our provision for income taxes; legal and contractual proceedings involving the Corporation; reliance on key personnel; labour relations matters; and development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2011 Annual MD&A and under the heading "Risk Factors" in our 2012 Annual Information Form.

Readers are urged to consider these factors carefully in evaluating the forward looking statements and are cautioned not to place undue reliance on these forward looking statements. The forward looking statements included in this document are made only as of the date hereof and we do not undertake to publicly update these forward looking statements to reflect new information, future events or otherwise, except as required by applicable laws. In light of these risks, uncertainties, and assumptions, the forward looking events might occur to a different extent or at a different time than we have described, or might not occur. We cannot assure that projected results or events will be achieved.

SUPPLEMENTAL INFORMATION

		Sept. 30, 2012	Dec. 31, 2011
Closing market price (TSX) ($)		**15.05**	21.02
Price range for the last 12 months (TSX) ($)	High	**21.37**	23.24
	Low	**14.11**	19.45
Debt to invested capital (%)		**55.3**	52.4
Debt to invested capital excluding non-recourse debt (%)		**52.9**	49.9
Return on equity attributable to common shareholders (%)		**(24.2)**	10.6
Comparable return on equity attributable to common shareholders[(1), (2)] (%)		**3.6**	8.4
Return on capital employed[(1)] (%)		**(3.3)**	8.3
Comparable return on capital employed[(1), (2)] (%)		**2.0**	7.0
Cash dividends per share[(1)] ($)		**1.16**	1.16
Price/comparable earnings ratio[(1)] (times)		**36.7**	20.2
Earnings coverage[(1)] (times)		**(1.2)**	2.7
Dividend payout ratio based on net earnings[(1)] (%)		**(41.7)**	66.9
Dividend payout ratio based on comparable earnings[(1), (2)] (%)		**281.7**	84.3
Dividend payout ratio based on funds from operations[(1), (2), (3)] (%)		**34.5**	24.0
Dividend yield[(1)] (%)		**7.7**	5.5
Cash flow to debt[(1), (3)] (%)		**18.3**	20.2
Cash flow to interest coverage[(1), (3)] (times)		**4.3**	4.4

(1) Last 12 months

(2) These ratios incorporate items that are not defined under IFRS. None of these measurements should be used in isolation or as a substitute for the Corporation's reported financial performance or position as presented in accordance with IFRS. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application. For a reconciliation of the Non-IFRS measures used in this calculation, refer to the Non-IFRS Measures section of this MD&A.

(3) These ratios have been adjusted for the impact of the Sundance Units 1 and 2 arbitration.

RATIO FORMULAS

Debt to invested capital = (long-term debt including current portion - cash and cash equivalents) / (long-term debt including current portion + non-controlling interests + equity attributable to shareholders - cash and cash equivalents)

Return on equity attributable to common shareholders = net earnings attributable to common shareholders or earnings on a comparable basis / average equity attributable to common shareholders excluding AOCI

Return on capital employed = (earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense) / average invested capital excluding AOCI

Price/comparable earnings ratio = current period's closing market price / comparable earnings per share

Earnings coverage = (net earnings attributable to common shareholders+ income taxes + net interest expense) / (interest on debt - interest income)

Dividend payout ratio = common share dividends / net earnings attributable to common shareholders or earnings on a comparable basis or funds from operations

Dividend yield = dividend per common share / current period's closing market price

Cash flow to debt = cash flow from operating activities before changes in working capital / average total debt – average cash and cash equivalents

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + interest on debt - interest income - capitalized interest) / (interest on debt - interest income)

GLOSSARY OF KEY TERMS

Alberta Power Purchase Arrangement (PPA) - A long-term arrangement established by regulation for the sale of electric energy from formerly regulated generating units to PPA Buyers.

Availability - A measure of the time, expressed as a percentage of continuous operation 24 hours a day, 365 days a year, that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Boiler - A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

British thermal unit (Btu) - A measure of energy. The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, when the water is near 39.2 degrees Fahrenheit.

Capacity - The rated continuous load-carrying ability, expressed in megawatts, of generation equipment.

Derate - To lower the rated electrical capability of a power generating facility or unit.

Flue Gas Desulphurization Unit (Scrubber) - Equipment used to remove sulphur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Force Majeure - Literally means “major force”. These clauses excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Geothermal Plant - A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigajoule (GJ) - A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt - A measure of electric power equal to 1,000 megawatts.

Gigawatt hour (GWh) - A measure of electricity consumption equivalent to the use of 1,000 megawatts of power over a period of one hour.

Greenhouse Gas (GHG) – Gases having potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Heat rate - A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

Megawatt (MW) - A measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) - A measure of electricity consumption equivalent to the use of 1,000,000 watts of power over a period of one hour.

Net Maximum Capacity - The maximum capacity or effective rating, modified for ambient limitations, that a generating unit or power plant can sustain over a specific period, less the capacity used to supply the demand of station service or auxiliary needs.

Renewable Plant - Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Spark Spread - A measure of gross margin per MW (sales price less cost of natural gas).

Supercritical Technology - The most advanced coal-combustion technology in Canada, employing a supercritical boiler, high-efficiency multi-stage turbine, flue gas desulphurization unit (scrubber), bag house, and low nitrogen oxide burners.

Turbine - A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Unplanned Outage - The shut down of a generating unit due to an unanticipated breakdown.

Uprate - To increase the rated electrical capability of a power generating facility or unit.

Value at Risk (VaR) - A measure to manage earnings exposure from energy trading activities.

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