TRANSALTA CORPORATION
SECOND 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 six months ended June 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 July 30, 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.

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

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Availability (%)(1)	**81.6**	76.9	**86.7**	83.7
Production (GWh)(1)	**8,274**	8,878	**17,715**	18,982
Revenues	**407**	515	**1,063**	1,333
Gross margin(2)	**256**	328	**725**	936
Operating income (loss)(2)	**(394)**	58	**(222)**	417
Comparable operating income(3)	**54**	141	**175**	301
Net earnings (loss) attributable to common shareholders	**(797)**	12	**(708)**	216
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(3.51)**	0.05	**(3.13)**	0.97
Comparable net earnings (loss) per share(3)	**(0.10)**	0.29	**0.10**	0.63
Comparable EBITDA(3)	**193**	262	**445**	535
Funds from operations(3)	**150**	226	**339**	452
Funds from operations per share(3)	**0.66**	1.02	**1.50**	2.04
Cash flow from operating activities	**78**	123	**261**	291
Free cash flow (deficiency)(3)	**(34)**	81	**(24)**	181
Dividends paid per common share	**0.29**	0.29	**0.58**	0.58

As at	**June 30, 2012**	Dec. 31, 2011
Total assets	**9,083**	9,736
Total long-term liabilities	**5,042**	4,918

AVAILABILITY & PRODUCTION

Availability for the three months ended June 30, 2012 increased compared to the same period 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 in 2012 at the Alberta coal PPA facilities, primarily at Keephills Units 1 and 2. There were no similar planned outages at the Alberta coal PPA facilities during the same period in 2011.

For the six months ended June 30, 2012, availability increased compared to the same period in 2011 primarily due to lower planned and unplanned outages at Centralia Thermal, partially offset by higher planned outages at the Alberta coal PPA facilities and higher unplanned outages at Genesee Unit 3.

Production for the three and six months ended June 30, 2012 decreased 604 gigawatt hours (“GWh”) and 1,267 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, and lower PPA customer demand, partially offset by lower planned and unplanned outages at Centralia Thermal and the commencement of commercial operations of Keephills Unit 3.

(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.

The outages at Centralia Thermal did not negatively impact our gross margins for the three and six months ended June 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. Availability, after adjusting for the higher economic dispatching at Centralia, was 87.2 per cent (June 30, 2011 - 89.2 per cent) and 89.5 per cent (June 30, 2011 - 91.4 per cent) for the three and six months ended June 30, 2012, respectively.

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 six months ended June 30, 2012 are presented below:

	3 months ended June 30	6 months ended June 30
Net earnings attributable to common shareholders, 2011	12	216
Decrease in Generation comparable gross margins	(6)	(33)
Mark-to-market movements and de-designations - Generation	(18)	(132)
Decrease in Energy Trading gross margins	(48)	(46)
Increase in depreciation and amortization expense	(19)	(34)
Decrease in gain on sale of facilities	(3)	-
Increase in asset impairment charges	(356)	(356)
Increase in inventory writedown	(8)	(42)
Increase in net interest expense	(16)	(27)
Decrease in equity income	(7)	(7)
Impact of Sundance Units 1 and 2 arbitration	(247)	(247)
(Increase) decrease in income tax expense	(82)	8
Increase in preferred share dividends	(3)	(6)
Other	4	(2)
Net loss attributable to common shareholders, 2012	**(797)**	**(708)**

Generation comparable gross margins, excluding the impact of mark-to-market movements, for the three months ended June 30, 2012 decreased $6 million compared to the same period in 2011 primarily due to higher planned outages at the Alberta coal PPA facilities, lower wind volumes, and unfavourable pricing, partially offset by the commencement of commercial operations of Keephills Unit 3, and higher hydro volumes.

For the six months ended June 30, 2012, Generation comparable gross margins, excluding the impact of mark-to-market movements, decreased $33 million compared to the same period in 2011 primarily due to higher planned outages at the Alberta coal PPA facilities, unfavourable pricing across the fleet, and higher unplanned outages at Genesee Unit 3, partially offset by the commencement of commercial operations of Keephills Unit 3 and higher wind and hydro volumes.

Mark-to-market movements decreased for the three and six months ended June 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 settled contracts recognized in the second quarter of 2012.

For the three and six months ended June 30, 2012, Energy Trading gross margins decreased compared to the same periods in 2011 primarily due to unexpected weather patterns, gas supply conditions that impacted gas prices, and power plant outages.

Depreciation and amortization expense for the three and six months ended June 30, 2012 increased compared to 2011 primarily due to an increased asset base, largely due to the commencement of commercial operations of Keephills Unit 3, and asset retirements.

The gain on sale of facilities in the prior period was a result of the sale of our interest in the Meridian facility.

Asset impairment charges for the three and six months ended June 30, 2012 increased due to the recognition of pre-tax 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.

The inventory writedown recorded in the three and six months ended June 30, 2012 is due to the 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. Under IFRS, if certain criteria are not met with respect to hedge relationships, hedge accounting is no longer permitted. When this occurs, the hedges are referred to as de-designated.

Net interest expense for the three and six months ended June 30, 2012 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 and six months ended June 30, 2012 decreased due to unfavourable market conditions at CE Generation, LLC (“CE Gen”).

Sundance Units 1 and 2 arbitration for the three and six months ended June 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 June 30, 2012 increased compared to the same period in 2011 due to 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, partially offset by an income tax recovery due to lower net earnings which included the impact of the Sundance Units 1 and 2 arbitration.

Income tax expense for the six months ended June 30, 2012 decreased compared to the same period in 2011 due to an income tax recovery 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 six months ended June 30, 2012 increased compared to the same periods in 2011 due to a higher balance of preferred shares outstanding during 2012.

FUNDS FROM OPERATIONS AND FREE CASH FLOW

Funds from operations for the three and six months ended June 30, 2012 decreased $76 million and $113 million, respectively, compared to the same periods in 2011 primarily due to lower comparable net earnings, after excluding the impact of the Sundance Units 1 and 2 arbitration from working capital.

After excluding the impact of the Sundance Units 1 and 2 arbitration from working capital, free cash flow for the three and six months ended June 30, 2012 decreased $115 million and $205 million, respectively, compared to the same periods 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 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 June 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 3* of our interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2012 for additional information regarding Sundance Units 1 and 2.

We will immediately start the work to safely restore the units to service. 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 quarter, a pre-tax impairment charge of $43 million was recorded as a result of, and included in the impact of, the Sundance arbitration. Please refer to the Sundance Units 1 and 2 section above for more details.

Other

During the three months ended June 30, 2012, 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.

Centralia Coal Inventory Impairment

During the three and six months ended June 30, 2012 we recognized a pre-tax impairment charge of $8 million and $42 million, respectively, related to the coal inventory at our Centralia plant. The impairment resulted from the previous de-designation of hedges at Centralia Thermal and the continued low price environment in the Pacific Northwest. During the three and six months ended June 30, 2012, we recognized nil and $85 million of pre-tax gains, respectively, 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, and with the continued low price environment we recognized a further impairment charge on the coal inventory.

During the first quarter, a comparable earnings adjustment was recognized for the inventory that was on hand at the time the hedges were de-designated. The impact of the impairment is to be recognized as that inventory is consumed. Of the $8 million and $42 million impact associated with the inventory impairment, $9 million of the impairment charge recognized in the current three month period relates to new deliveries of coal inventories and is considered comparable in nature. Accordingly, a $1 million pre-tax recovery and a $33 million pre-tax loss, for the three and six months ended June 30, 2012, respectively, has been adjusted in calculating earnings on a comparable basis. Please refer to the Non-IFRS Measures section of this MD&A.

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 we are expecting to achieve a 40 megawatt (“MW”) efficiency uprate 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, Capital Power, 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 at this time. The impact of the cancellation of the project is not expected to be material for the 2012 results.

Six months ended June 30, 2012

MF Global Inc.

During the first quarter, we filed our claim with the Administrator in the United Kingdom ("U.K.") related to our collateral on foreign futures transactions that would have been in the accounts in the U.K. There have been no additional funds returned during the six months ended June 30, 2012 and our provision of U.S.$18 million associated with the U.S.$36 million of collateral remains unchanged. Please refer to the Significant Events section of our 2011 Annual Report for additional information regarding MF Global Inc.

SUBSEQUENT EVENTS

Centralia Thermal

On July 25, 2012, we announced that we have 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.

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.*

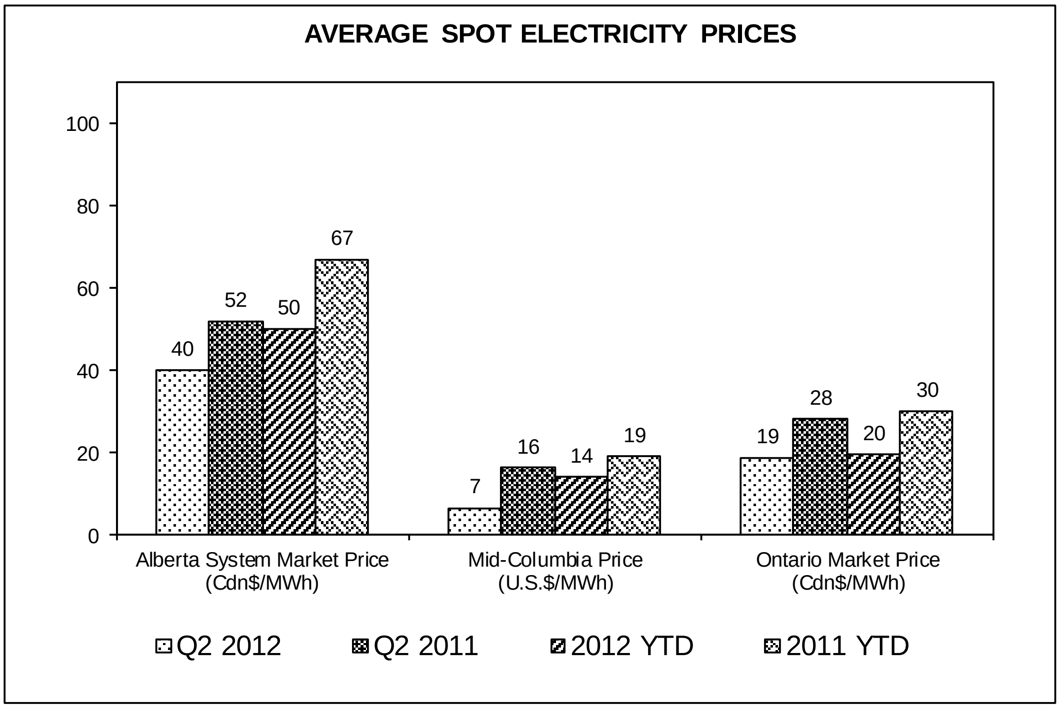
Contracted Cash Flows

During the second quarter of 2012, more than 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 six months ended June 30, 2012 and 2011 in our three major markets are shown in the following graphs.

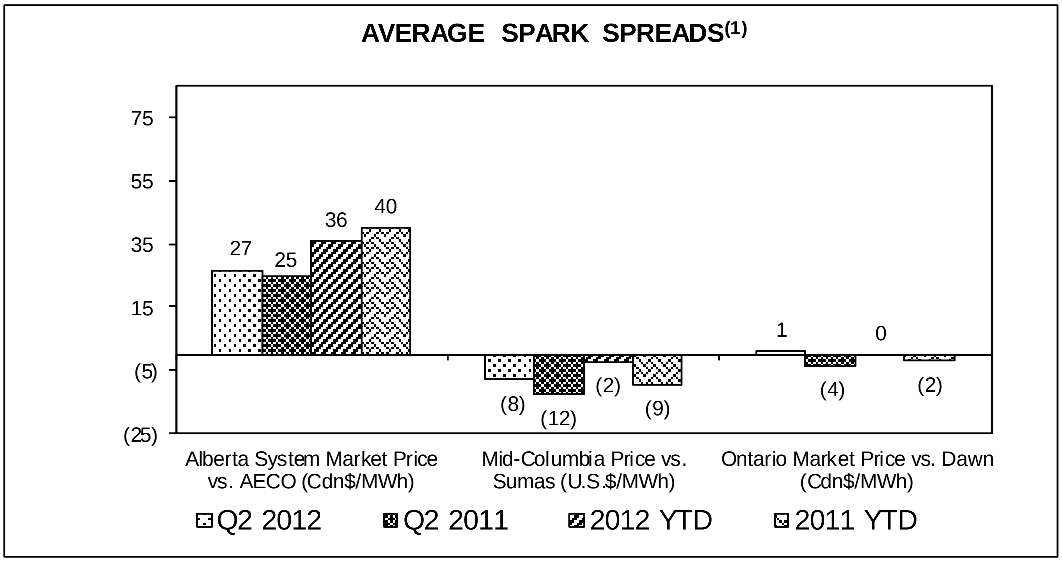


For the three and six months ended June 30, 2012, average spot prices decreased in Alberta compared to the same periods in 2011 due to lower natural gas prices and lower weather driven demand. In the Pacific Northwest and Ontario, average spot prices decreased due to lower natural gas prices.

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 six months ended June 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 months ended June 30, 2012, average spark spreads increased in all of our major markets due to lower natural gas prices.

For the six months ended June 30, 2012, average spark spreads decreased in Alberta due to lower power prices. In the Pacific Northwest and Ontario, average spark spreads increased due to lower natural gas prices.

GENERATION: *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 June 30, 2012, our generating assets had 8,213 MW of gross generating capacity[1] in operation (7,870 MW net ownership interest) and 83 MW net under construction. 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 June 30	**Total**	**Comparable adjustments**	**Comparable total[2]**	**Per installed MWh**	Comparable total[2]	Per installed MWh
Revenues	**418**	**83**	**501**	**27.93**	543	31.23
Fuel and purchased power	**151**	**-**	**151**	**8.42**	187	10.75
Gross margin	**267**	**83**	**350**	**19.51**	356	20.48
Operations, maintenance, and administration	**105**	**(1)**	**104**	**5.80**	104	5.98
Depreciation and amortization	**134**	**-**	**134**	**7.47**	109	6.27
Asset impairment charges	**365**	**(365)**	**-**	**-**	-	-
Inventory writedown	**8**	**1**	**9**	**0.50**	-	-
Taxes, other than income taxes	**7**	**-**	**7**	**0.39**	7	0.40
Intersegment cost allocation	**4**	**-**	**4**	**0.22**	2	0.12
Operating income (loss)	**(356)**	**448**	**92**	**5.13**	134	7.71
Installed capacity (GWh)	**17,937**		**17,937**		17,389	
Production (GWh)	**7,852**		**7,852**		8,368	
Availability (%)	**81.1**		**81.1**		75.4	

	2012				2011	
6 months ended June 30	**Total**	**Comparable adjustments**	**Comparable total[2]**	**Per installed MWh**	Comparable total[2]	Per installed MWh
Revenues	**1,057**	**(2)**	**1,055**	**29.48**	1,147	33.20
Fuel and purchased power	**338**	**-**	**338**	**9.44**	397	11.49
Gross margin	**719**	**(2)**	**717**	**20.04**	750	21.71
Operations, maintenance and administration	**203**	**(1)**	**202**	**5.64**	204	5.91
Depreciation and amortization	**258**	**-**	**258**	**7.21**	218	6.31
Asset impairment charges	**365**	**(365)**	**-**	**-**	-	-
Inventory writedown	**42**	**(33)**	**9**	**0.25**	-	-
Taxes, other than income taxes	**14**	**-**	**14**	**0.39**	14	0.41
Intersegment cost allocation	**7**	**-**	**7**	**0.20**	4	0.12
Operating income (loss)	**(170)**	**397**	**227**	**6.35**	310	8.96
Installed capacity (GWh)	**35,788**		**35,788**		34,546	
Production (GWh)	**16,765**		**16,765**		17,927	
Availability (%)	**86.3**		**86.3**		82.8	

(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 June 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	**4,732**	**7,032**	**224**	**94**	**130**	**31.85**	**13.37**	**18.48**
Gas	**546**	**778**	**21**	**4**	**17**	**26.99**	**5.14**	**21.85**
Renewables	**935**	**2,921**	**47**	**3**	**44**	**16.09**	**1.03**	**15.06**
Total Western Canada	**6,213**	**10,731**	**292**	**101**	**191**	**27.21**	**9.41**	**17.80**
Gas	**958**	**1,638**	**86**	**37**	**49**	**52.50**	**22.59**	**29.91**
Renewables	**335**	**1,442**	**32**	**2**	**30**	**22.19**	**1.39**	**20.80**
Total Eastern Canada	**1,293**	**3,080**	**118**	**39**	**79**	**38.31**	**12.66**	**25.65**
Coal	**-**	**2,929**	**63**	**5**	**58**	**21.51**	**1.71**	**19.80**
Gas	**346**	**1,197**	**28**	**6**	**22**	**23.39**	**5.01**	**18.38**
Total International	**346**	**4,126**	**91**	**11**	**80**	**22.06**	**2.67**	**19.39**
	7,852	**17,937**	**501**	**151**	**350**	**27.93**	**8.42**	**19.51**

3 months ended June 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	5,274	6,436	216	95	121	33.56	14.76	18.80
Gas	655	832	29	10	19	34.86	12.02	22.84
Renewables	884	2,913	50	2	48	17.16	0.69	16.47
Total Western Canada	6,813	10,181	295	107	188	28.98	10.51	18.47
Gas	819	1,638	100	56	44	61.05	34.19	26.86
Renewables	383	1,444	37	2	35	25.62	1.39	24.23
Total Eastern Canada	1,202	3,082	137	58	79	44.45	18.82	25.63
Coal	-	2,929	80	13	67	27.31	4.44	22.87
Gas	353	1,197	31	9	22	25.90	7.52	18.38
Total International	353	4,126	111	22	89	26.90	5.33	21.57
	8,368	17,389	543	187	356	31.23	10.75	20.48

6 months ended June 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	**9,995**	**13,976**	**446**	**187**	**259**	**31.91**	**13.38**	**18.53**
Gas	**1,250**	**1,556**	**52**	**10**	**42**	**33.42**	**6.43**	**26.99**
Renewables	**1,686**	**5,842**	**95**	**6**	**89**	**16.26**	**1.03**	**15.23**
Total Western Canada	**12,931**	**21,374**	**593**	**203**	**390**	**27.74**	**9.50**	**18.25**
Gas	**1,961**	**3,276**	**185**	**80**	**105**	**56.47**	**24.42**	**32.05**
Renewables	**795**	**2,886**	**77**	**4**	**73**	**26.68**	**1.39**	**25.29**
Total Eastern Canada	**2,756**	**6,162**	**262**	**84**	**178**	**42.52**	**13.63**	**28.89**
Coal	**404**	**5,858**	**145**	**37**	**108**	**24.75**	**6.32**	**18.43**
Gas	**674**	**2,394**	**55**	**14**	**41**	**22.97**	**5.85**	**17.12**
Total International	**1,078**	**8,252**	**200**	**51**	**149**	**24.24**	**6.18**	**18.06**
	16,765	**35,788**	**1,055**	**338**	**717**	**29.48**	**9.44**	**20.04**

(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.

6 months ended June 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	10,820	12,802	420	154	266	32.81	12.03	20.78
Gas	1,397	1,655	67	19	48	40.48	11.48	29.00
Renewables	1,595	5,753	101	5	96	17.56	0.87	16.69
Total Western Canada	13,812	20,210	588	178	410	29.09	8.81	20.28
Gas	1,825	3,258	217	121	96	66.61	37.14	29.47
Renewables	793	2,872	76	4	72	26.46	1.39	25.07
Total Eastern Canada	2,618	6,130	293	125	168	47.80	20.39	27.41
Coal	816	5,825	205	75	130	35.19	12.88	22.31
Gas	681	2,381	61	19	42	25.62	7.98	17.64
Total International	1,497	8,206	266	94	172	32.42	11.46	20.96
	17,927	34,546	1,147	397	750	33.20	11.49	21.71

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 six months ended June 30, 2012 are presented below:

	3 months ended June 30 (GWh)	**6 months ended June 30 (GWh)**
Production, 2011	6,813	13,812
Higher planned outages at the Alberta coal PPA facilities	(564)	(799)
Lower PPA customer demand	(413)	(780)
Market curtailments	(140)	(162)
Higher unplanned outages at Genesee Unit 3	(31)	(116)
Lower production at natural gas-fired facilities	(79)	(87)
Commencement of commercial operations of Keephills Unit 3	434	883
Lower unplanned outages at the Alberta coal PPA facilities	106	62
(Lower) higher wind volumes	(31)	48
Higher hydro volumes	82	43
Other	36	27
Production, 2012	**6,213**	**12,931**

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

	3 months ended June 30	6 months ended June 30
Comparable gross margin, 2011	188	410
Higher planned outages at the Alberta coal PPA facilities	(14)	(32)
Unfavourable coal pricing	(3)	(6)
Higher unplanned outages at Genesee Unit 3	(1)	(6)
Favourable (unfavourable) pricing	3	(3)
Lower unplanned outages at the Alberta coal PPA facilities	4	(2)
Commencement of commercial operations of Keephills Unit 3	12	31
Higher hydro margins	8	2
(Lower) higher wind volumes	(1)	2
Other	(5)	(6)
Comparable gross margin, 2012	**191**	**390**

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 six months ended June 30, 2012 are presented below:

	3 months ended June 30 (GWh)	6 months ended June 30 (GWh)
Production, 2011	1,202	2,618
Favourable market conditions at natural gas-fired facilities	138	135
(Lower) higher wind volumes	(44)	14
Other	(3)	(11)
Production, 2012	**1,293**	**2,756**

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

	3 months ended June 30	6 months ended June 30
Gross margin, 2011	79	168
Favourable contracted gas input costs	4	9
Lower wind volumes	(4)	-
Other	-	1
Gross margin, 2012	**79**	**178**

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 six months ended June 30, 2012 are presented below:

	3 months ended June 30 (GWh)	6 months ended June 30 (GWh)
Production, 2011	353	1,497
Higher economic dispatching at Centralia Thermal	(1,272)	(2,011)
Lower planned and unplanned outages at Centralia Thermal	1,272	1,602
Other	(7)	(10)
Production, 2012	**346**	**1,078**

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

	3 months ended June 30	6 months ended June 30
Comparable gross margin, 2011	89	172
Unfavourable pricing, including purchased power prices	(11)	(31)
Favourable foreign exchange	-	1
Other	2	7
Comparable gross margin, 2012	**80**	**149**

The outages at Centralia Thermal did not negatively impact our gross margins for the three and six months ended June 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. Availability, after adjusting for the higher economic dispatching at Centralia, was 87.2 per cent (June 30, 2011 - 89.2 per cent) and 89.5 per cent (June 30, 2011 - 91.4 per cent) for the three and six months ended June 30, 2012, respectively.

Operations, Maintenance, and Administration Expense

Operations, maintenance, and administration ("OM&A") expenses for the three and six months ended June 30, 2012 were comparable to the same periods in 2011.

Depreciation and Amortization Expense

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

	3 months ended June 30	6 months ended June 30
Depreciation and amortization expense, 2011	113	222
Increase in asset base	11	21
Asset retirements	10	13
Unfavourable foreign exchange	1	2
Other	(1)	-
Depreciation and amortization expense, 2012	**134**	**258**

Finance Lease

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 June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Availability (%)	**69.5**	94.4	**86.0**	99.9
Production (GWh)	**82**	114	**219**	233

Availability for the three and six months ended June 30, 2012 decreased compared to the same periods in 2011 due to higher planned outages and seasonal derates due to milder than expected winter temperatures.

Production for the three and six months ended June 30, 2012 decreased by 32 GWh and 14 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 six months ended June 30, 2012 was consistent with the same periods in 2011 at $2 million and $4 million, respectively.

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

Equity Investments

Our interests in the CE Gen and Wailuku 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 June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Availability (%)	**93.2**	100.0	**93.1**	95.3
Production (GWh)				
Gas	**44**	80	**135**	205
Renewables	**296**	316	**596**	617
Total production	**340**	396	**731**	822

Availability for the three and six months ended June 30, 2012 decreased compared to the same periods in 2011 due to higher planned and unplanned outages.

Production for the three and six months ended June 30, 2012 decreased compared to the same periods in 2011 due to unfavourable market conditions and higher planned and unplanned outages.

Equity income for the three and six months ended June 30, 2012 decreased due to unfavourable market conditions.

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 8* of our interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2012 for additional financial information regarding our equity accounted investments.

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 June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Revenues	**(11)**	37	**6**	52
Fuel and purchased power	**-**	-	**-**	-
Gross margin	**(11)**	37	**6**	52
Operations, maintenance, and administration	**6**	10	**13**	15
Depreciation and amortization	**-**	1	**-**	1
Intersegment cost allocation	**(4)**	(2)	**(7)**	(4)
Operating income (loss)	**(13)**	28	**-**	40

For the three and six months ended June 30, 2012, Energy Trading gross margins decreased compared to the same periods in 2011 primarily due to unexpected weather patterns, gas supply conditions that impacted gas prices, and power plant outages.

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

For the three and six months ended June 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 June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Operations, maintenance, and administration	**20**	15	**42**	38
Depreciation and amortization	**5**	6	**10**	11
Operating loss	**25**	21	**52**	49

For the three and six months ended June 30, 2012, OM&A expenses increased compared to the same periods in 2011 due to costs associated with several productivity initiatives and higher compensation costs.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Interest on debt	**58**	55	**114**	110
Capitalized interest	**(1)**	(12)	**(1)**	(23)
Other	**2**	1	**2**	1
Interest expense	**59**	44	**115**	88
Accretion of provisions	**5**	4	**9**	9
Net interest expense	**64**	48	**124**	97

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

	3 months ended June 30	6 months ended June 30
Net interest expense, 2011	48	97
Lower capitalized interest	11	22
Higher interest rates	3	5
Unfavourable foreign exchange impacts	1	1
Lower debt levels	(1)	(3)
Higher interest income	(1)	(1)
Higher financing costs	3	3
Net interest expense, 2012	**64**	**124**

INCOME TAXES

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

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Earnings (loss) before income taxes	**(710)**	16	**(599)**	329
Income attributable to non-controlling interests	**(5)**	(7)	**(18)**	(20)
Equity income (loss)	**5**	(2)	**5**	(2)
Impacts associated with certain de-designated and ineffective hedges	**83**	65	**(2)**	(134)
Asset impairment charges	**365**	9	**365**	9
Inventory writedown	**(1)**	-	**33**	-
Gain on sale of facilities	**-**	(3)	**(3)**	(3)
Sundance Units 1 and 2 arbitration	**247**	-	**247**	-
Other non-comparable items	**1**	9	**1**	9
Earnings (loss) attributable to TransAlta shareholders, excluding non-comparable items, subject to tax	**(15)**	87	**29**	188
Income tax expense (recovery)	**76**	(6)	**78**	86
Income tax recovery (expense) related to impacts associated with certain de-designated and ineffective hedges	**29**	23	**(1)**	(47)
Income tax recovery related to asset impairment charges	**5**	2	**5**	2
Income tax recovery related to inventory writedown	**-**	-	**12**	-
Income tax expense related to gain on sale of facilities	**-**	(1)	**(1)**	(1)
Income tax recovery related to Sundance Units 1 and 2 arbitration	**63**	-	**63**	-
Income tax expense related to writeoff of deferred income tax assets	**(169)**	-	**(169)**	-
Income tax expense related to changes in corporate income tax rates	**(8)**	-	**(8)**	-
Income tax recovery related to the resolution of certain outstanding tax matters		-	**9**	-
Income tax recovery related to other non-comparable items	**-**	3	**-**	3
Income tax expense (recovery) excluding non-comparable items	**(4)**	21	**(12)**	43
Effective tax rate on earnings (loss) attributable to TransAlta shareholders excluding non-comparable items (%)	**27**	24	**41**	23

The income tax expense (recovery) excluding non-comparable items for the three months ended June 30, 2012 decreased compared to the same period in 2011 due to lower comparable earnings and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The income tax expense (recovery) excluding non-comparable items for the six months ended June 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 June 30, 2012 increased compared to the same period in 2011 due to the effect of lower earnings, the effect of certain deductions that do not fluctuate with earnings, and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the six months ended June 30, 2012 increased compared to the same period in 2011 due to the effect of certain deductions that do not fluctuate with 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.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three and six months ended June 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 June 30, 2012:

	Increase/ (Decrease)	**Primary factors explaining change**
Cash and cash equivalents	12	Timing of receipts and payments
Accounts receivable	(76)	Timing of customer receipts and lower revenues
Prepaid expenses	13	Prepayments of annual insurance premiums
Income taxes receivable	14	Resolution of certain tax matters
Inventory	14	Lower production at our coal facilities, higher average coal costs, partially offset by writedown of coal inventory
Property, plant, and equipment, net	(380)	Asset impairments and depreciation partially offset by additions
Deferred income tax assets	(126)	Writeoff of deferred income tax assets related to profitability of U.S. operations
Risk management assets (current and long-term)	(114)	Price movements and changes in underlying positions
Accounts payable and accrued liabilities	150	Sundance Units 1 and 2 arbitration impacts, partially offset by timing of payments and lower capital accruals
Income taxes payable	(15)	Increase in instalment payments
Long-term debt (including current portion)	238	Increased borrowings under credit facilities partially offset by repayments
Decommissioning and other provisions (current and long-term)	(62)	Decrease in decommissioning and commercial provisions, including the Sundance Units 1 and 2 arbitration impacts
Deferred credits and other long-term liabilities	22	Increase in defined benefit accrual
Deferred income tax liabilities	(79)	Positive resolution of certain tax matters and the Sundance Units 1 and 2 arbitration impacts
Risk management liabilities (current and long-term)	(51)	Price movements and changes in underlying positions
Equity attributable to shareholders	(830)	Net loss for the period and share dividends
Non-controlling interests	(22)	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 11* of our interim condensed consolidated financial statements as at and for the three and six months ended June 30, 2012 for details on Financial Instruments. Refer to the Risk Management section of our 2011 Annual Report and *Note 12* 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 June 30, 2012, total Level III financial instruments had a net asset carrying value of $12 million (Dec. 31, 2011 - $7 million net liability).

During the three and six months ended June 30, 2012, unrealized pre-tax gains of nil (June 30, 2011 - nil) and $75 million (June 30, 2011 - $204 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. These unrealized gains were calculated using current forward prices which will change between now and the time 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 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 June 30, 2012, cumulative gains of $15 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur. The prospective changes in fair value of the derivatives from the date of discontinuing hedge accounting will be recognized in net earnings in the period they occur.

STATEMENTS OF CASH FLOWS

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

3 months ended June 30	2012	2011	Primary factors explaining change
Cash and cash equivalents, beginning of period	**31**	40	
Provided by (used in):			
Operating activities	**78**	123	Lower cash earnings of $76 million partially offset by favourable changes in working capital of $31 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration
Investing activities	**(175)**	(86)	Increase in additions to PP&E and intangibles of $77 million and a decrease in proceeds on sale of facilities of $30 million, partially offset by a net positive cash impact of $52 million related to changes in collateral received from or paid to counterparties
Financing activities	**127**	(41)	Decreased debt repayments and a decrease in common share cash dividends of $25 million due to dividends reinvested through the dividend reinvestment plan, partially offset by a decrease in borrowings under credit facilities and an increase in preferred share dividends of $3 million
Translation of foreign currency cash	**-**	2	
Cash and cash equivalents, end of period	**61**	38	

6 months ended June 30	2012	2011	Primary factors explaining change
Cash and cash equivalents, beginning of period	**49**	35	
Provided by (used in):			
Operating activities	**261**	291	Lower cash earnings of $113 million partially offset by favourable changes in working capital of $83 million, net of a $204 million impact associated with the Sundance Units 1 and 2 arbitration
Investing activities	**(340)**	(219)	Increase in additions to PP&E and intangibles of $128 million and a decrease in proceeds on sale of facilities of $27 million, partially offset by a net positive impact of $71 million related to changes in collateral received from or paid to counterparties
Financing activities	**91**	(70)	Decrease debt repayments and a decrease in common share cash dividends of $27 million due to dividends reinvested through the dividend reinvestment plan, partially offset by a decrease in borrowings under credit facilities and an increase in preferred share dividends of $7 million
Translation of foreign currency cash	**-**	1	
Cash and cash equivalents, end of period	**61**	38	

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 preferred shares 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 $4.3 billion at June 30, 2012 and $4.0 billion at Dec. 31, 2011. Total long-term debt increased from Dec. 31, 2011 primarily due to unfavourable changes in foreign exchange rates and higher borrowings on our credit facilities.

Credit Facilities

At June 30, 2012, we have a total of $2.4 billion (Dec. 31, 2011 - $2.0 billion) of committed credit facilities of which $1.1 billion (Dec. 31, 2011 - $0.9 billion) is not drawn and is available, subject to customary borrowing conditions. At June 30, 2012, the $1.3 billion (Dec. 31, 2011 - $1.1 billion) of credit utilized under these facilities is comprised of actual drawings of $1.0 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, 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 $1.1 billion available under the credit facilities, we also have $32 million of cash available.

Share Capital

On July 30, 2012, we had 230.0 million common shares outstanding and 12.0 million Series A and 11.0 million Series C first preferred shares outstanding. At June 30, 2012, we had 227.0 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. At June 30, 2012, we also had 12.0 million (Dec. 31, 2011 - 12.0 million) Series A and 11.0 million (Dec. 31, 2011 - 11.0 million) Series C 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 our Dividend Reinvestment and Share Purchase Plan. The amended and restated plan is now called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (‘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 June 30, 2012, 2.4 million (June 30, 2011 - 0.8 million) common shares were issued for $43 million (June 30, 2011 - $17 million), which was comprised of $42 million (June 30, 2011 - $16 million) for dividends reinvested under the terms of the Plan and other proceeds of $1 million (June 30, 2011 - $1 million). During the six months ended June 30, 2012, 3.4 million (June 30, 2011 - 1.7 million) common shares were issued for $64 million (June 30, 2011 - $35 million), which was comprised of $62 million (June 30, 2011 - $33 million) for dividends reinvested under the terms of the Plan and other proceeds of $2 million (June 30, 2011 - $2 million).

We employ a variety of share-based payment plans to align employee and corporate objectives. During the six months ended June 30, 2012, a nominal number of employee stock options were exercised, expired or were cancelled (June 30, 2011 - 0.4 million). During the six months ended June 30, 2012, 1.7 million (June 30, 2011 - 1.4 million) Performance Share Ownership Plan units were granted and a nominal number (June 30, 2011 - nil) were awarded and exchanged for common shares.

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 June 30, 2012, we provided letters of credit totalling $297 million (Dec. 31, 2011 - $328 million) and cash collateral of $36 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

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, as new Greenhouse Gas (“GHG”) regulations for coal-fired power are developed there is a risk that the CASA air pollutant requirements and schedules become misaligned with 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 both the federal and provincial governments to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into the consideration the reliability and cost of Alberta’s generation supply.

On Aug. 27, 2011, the Government of Canada published, in the Canada Gazette, draft regulations entitled “Reduction of CO_2 Emissions from Coal-Fired Generation of Electricity”. These regulations propose a 45-year end-of-life for coal-fired power units, at which point the units would have to meet a GHG emissions performance standard similar to natural gas-fired levels, or close. Should they be passed, the regulations would become effective on July 1, 2015.

In the U.S., the Environmental Protection Agency (“EPA”) proposed, on March 27, 2012, 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, there is no material impact on our existing coal units at Centralia. The draft standards are currently open for public review, and are expected to be finalized later in 2012.

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

Over the balance of 2012, power prices in Alberta are expected to be lower than 2011, driven by lower natural gas prices, partially offset by continued load growth. In the Pacific Northwest, we continue to expect weak prices due to historically low natural gas prices, weak load growth, the addition of wind assets, and above normal precipitation which impacts available hydro energy.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has indicated its intention to regulate greenhouse gas emissions from coal-fired power units by 2015. This regulatory framework is under discussion between the federal and provincial governments and the industry, and is expected to be finalized in 2012.

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 in 2012, 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.

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 the first half of 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 second 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 increase for the remainder of 2012 due to the remaining uprate at our Alberta coal PPA facility and the completion of our 68 MW New Richmond wind project. Although the uprate 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 and unplanned outages and lower economic dispatching. 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 second 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 four per cent compared to 2011 due to the drivers mentioned above and lower coal production volumes, offset by productivity initiatives.

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, 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 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.

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 2012 objective is for Energy Trading to contribute between $50 million and $70 million in gross margin.

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. 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 Capital Expenditures

We have two significant growth capital projects that are currently in progress with targeted completion dates of Q4 2012. A summary of each of these projects is outlined below:

	Total Project		2012			
Project	**Estimated spend**	**Spent to date[1]**	**Estimated spend**	**Spent to date[1]**	**Target completion date**	**Details**
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	15	15 - 20	4	Q4 2012	An expected 15 MW efficiency uprate at our Sundance facility
New Richmond[3]	205	78	165 - 185	49	Q4 2012	A 68 MW wind farm in Quebec
Total growth	**283**	**143**	**200 - 245**	**80**		

Transmission

For the three and six months ended June 30, 2012, a total of $1 million and $2 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[4]

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[5]**
Routine capital	Expenditures to maintain our existing generating capacity	100 - 115	53
Productivity capital	Projects to improve power production efficiency	50 - 70	26
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	40 - 50	17
Planned maintenance	Regularly scheduled major maintenance	265 - 285	152
Total sustaining and productivity expenditures		**455 - 520**	**248**

(1) Represents amounts spent as of June 30, 2012. In 2012, we also spent a combined $1 million on Keephills Unit 3, Ardenville, Kent Hills 2, and Bone Creek. During the second quarter, we transferred $1 million from growth capital projects to sustaining capital expenditures for capital spares.

(2) Although the uprate will 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.

(4) Excludes any expenditures for Sundance Units 1 and 2 at this time as we are still determining the amounts to be incurred in 2012.

(5) Represents amounts incurred as of June 30, 2012.

Details of the 2012 planned maintenance program, including major inspection costs, are outlined as follows:

	Coal	Gas and Renewables	Expected spend in 2012	Spent to date(1)
Capitalized	215 - 230	50 - 55	265 - 285	152
Expensed	-	0 - 5	0 - 5	-
	215 - 230	50 - 60	265 - 290	152

	Coal	Gas and Renewables	Expected total	Lost to date
GWh lost	3,565 - 3,575	255 - 265	3,820 - 3,840	2,853

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, reinvested dividends under the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan, and capital markets. The funds required for committed growth and 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.

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 six months ended June 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.

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

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 for the second quarter of 2012, we have also excluded 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 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 June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Net earnings (loss) attributable to common shareholders	**(797)**	12	**(708)**	216
Impacts associated with certain de-designated and ineffective hedges, net of tax	**54**	42	**(1)**	(87)
Asset impairment charges, net of tax	**360**	7	**360**	7
Inventory writedown, net of tax	**(1)**	-	**21**	-
Sundance Units 1 and 2 arbitration, net of tax	**184**	-	**184**	-
Income tax expense related to writeoff of deferred income tax assets	**169**	-	**169**	-
Income tax expense related to changes in corporate income tax rates	**8**	-	**8**	-
Income tax recovery related to the resolution of certain tax matters	**-**	-	**(9)**	-
Gain on sale of facilities, net of tax	**-**	(2)	**(2)**	(2)
Writeoff of Project Pioneer costs, net of tax	**1**	-	**1**	-
Writeoff of wind development costs, net of tax	**-**	3	**-**	3
Writedown of capital spares, net of tax	**-**	3	**-**	3
Net earnings (loss) on a comparable basis	**(22)**	65	**23**	140
Weighted average number of common shares outstanding in the period	**227**	222	**226**	222
Net earnings (loss) on a comparable basis per share	**(0.10)**	0.29	**0.10**	0.63

Comparable Gross Margin

Comparable gross margin is calculated as follows:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Gross margin(1)	**256**	328	**725**	936
Impacts associated with certain de-designated and ineffective hedges	**83**	65	**(2)**	(134)
Impacts to revenue associated with Sundance Units 1 and 2(2)	**(10)**	(9)	**(20)**	(23)
Comparable gross margin	**329**	384	**703**	779

(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 June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Operating income (loss)[1]	**(394)**	58	**(222)**	417
Impacts associated with certain de-designated and ineffective hedges	**83**	65	**(2)**	(134)
Asset impairment charges	**365**	9	**365**	9
Inventory writedown	**(1)**	-	**33**	-
Writeoff of Project Pioneer costs	**1**	-	**1**	-
Writeoff of wind development costs	**-**	5	**-**	5
Writedown of capital spares	**-**	4	**-**	4
Comparable operating income	**54**	141	**175**	301

Comparable 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 June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Operating income (loss)[1]	**(394)**	58	**(222)**	417
Asset impairment charges	**365**	9	**365**	9
Inventory writedown	**(1)**	-	**33**	-
Depreciation and amortization per the Consolidated Statements of Cash Flows[2]	**149**	130	**290**	257
Impacts associated with certain de-designated and ineffective hedges	**83**	65	**(2)**	(134)
Impacts to revenue associated with Sundance Units 1 and 2[3]	**(10)**	(9)	**(20)**	(23)
Writeoff of Project Pioneer costs	**1**	-	**1**	-
Writeoff of wind development costs	**-**	5	**-**	5
Writedown of capital spares	**-**	4	**-**	4
Comparable EBITDA	**193**	262	**445**	535

(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 June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Cash flow from operating activites	**78**	123	**261**	291
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**204**	-	**204**	-
Change in non-cash operating working capital balances	**(132)**	103	**(126)**	161
Funds from operations	**150**	226	**339**	452
Weighted average number of common shares outstanding in the period	**227**	222	**226**	222
Funds from operations per share	**0.66**	1.02	**1.50**	2.04

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 June 30, 2012 represents total additions to property, plant, and equipment and intangibles per the Condensed Consolidated Statements of Cash Flows less $45 million that we have invested in growth projects. For the same period in 2011, we invested $34 million in growth projects. For the six months ended June 30, 2012 and 2011, we invested $82 million and $68 million, respectively, in growth projects.

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

	3 months ended June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Cash flow from operating activities	**78**	123	**261**	291
Add (deduct):				
Impacts to working capital associated with Sundance Units 1 and 2 arbitration	**204**	-	**204**	-
Changes in non-cash operating working capital	**(132)**	103	**(126)**	161
Sustaining capital and productivity expenditures	**(141)**	(76)	**(248)**	(134)
Dividends paid on common shares[1]	**(23)**	(48)	**(68)**	(95)
Dividends paid on preferred shares	**(6)**	(3)	**(14)**	(7)
Distributions paid to subsidiaries' non-controlling interests	**(14)**	(18)	**(33)**	(35)
Free cash flow (deficiency)	**(34)**	81	**(24)**	181

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

(1) Net of dividends reinvested under the Plan.

SELECTED QUARTERLY INFORMATION

	Q3 2011	Q4 2011	Q1 2012	**Q2 2012**
Revenue	629	701	656	**407**
Net earnings (loss) attributable to common shareholders	50	24	89	**(797)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.22	0.11	0.40	**(3.51)**
Comparable earnings (loss) per share	0.27	0.13	0.20	**(0.10)**

	Q3 2010	Q4 2010	Q1 2011	Q2 2011
Revenue	651	779	818	515
Net earnings attributable to common shareholders	40	92	204	12
Net earnings per share attributable to common shareholders, basic and diluted	0.18	0.42	0.92	0.05
Comparable earnings per share	0.18	0.36	0.34	0.29

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 June 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 those 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 their attendant costs; 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; our estimated spend on growth and sustaining capital and productivity projects; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expected impact of load growth and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; 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 impact of certain hedges on future reported earnings and cash flows; 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; 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.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(in millions of Canadian dollars except per share amounts)

Unaudited	**3 months ended June 30** 2012	2011	**6 months ended June 30** 2012	2011
Revenues *(Note 4)*	**407**	515	**1,063**	1,333
Fuel and purchased power *(Note 5)*	**151**	187	**338**	397
Gross margin	**256**	328	**725**	936
Operations, maintenance, and administration *(Note 5)*	**131**	134	**258**	262
Depreciation and amortization	**139**	120	**268**	234
Asset impairment charges *(Note 6)*	**365**	9	**365**	9
Inventory writedown *(Note 14)*	**8**	-	**42**	-
Taxes, other than income taxes	**7**	7	**14**	14
Operating income (loss)	**(394)**	58	**(222)**	417
Finance lease income	**2**	2	**4**	4
Equity income (loss) *(Note 8)*	**(5)**	2	**(5)**	2
Sundance Units 1 and 2 arbitration *(Note 3)*	**(247)**	-	**(247)**	-
Gain on sale of facilities *(Note 7)*	**-**	3	**3**	3
Other income	**1**	1	**1**	1
Foreign exchange loss	**(3)**	(2)	**(9)**	(1)
Net interest expense *(Notes 9 and 12)*	**(64)**	(48)	**(124)**	(97)
Earnings (loss) before income taxes	**(710)**	16	**(599)**	329
Income tax expense (recovery) *(Note 10)*	**76**	(6)	**78**	86
Net earnings (loss)	**(786)**	22	**(677)**	243
Net earnings (loss) attributable to:				
TransAlta shareholders	**(791)**	15	**(695)**	223
Non-controlling interests	**5**	7	**18**	20
	(786)	22	**(677)**	243
Net earnings (loss) attributable to TransAlta shareholders	**(791)**	15	**(695)**	223
Preferred share dividends *(Note 23)*	**6**	3	**13**	7
Net earnings (loss) attributable to common shareholders	**(797)**	12	**(708)**	216
Weighted average number of common shares outstanding in the period *(millions)*	**227**	222	**226**	222
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(3.51)**	0.05	**(3.13)**	0.97

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2012**	2011	**2012**	2011
Net earnings (loss)	**(786)**	22	**(677)**	243
Other comprehensive income (loss)				
Gains (losses) on translating net assets of foreign operations	**45**	5	**13**	(44)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(1)	**(32)**	(7)	**(11)**	26
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**18**	8	**9**	(50)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(3)	**-**	-	**1**	-
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(39)**	(22)	**(48)**	(154)
Net actuarial losses on defined benefit plans, net of tax(5)	**(14)**	(22)	**(24)**	(21)
Other comprehensive loss	**(22)**	(38)	**(60)**	(243)
Total comprehensive loss	**(808)**	(16)	**(737)**	-
Total comprehensive income (loss) attributable to:				
Common shareholders	**(813)**	(17)	**(748)**	(18)
Non-controlling interests	**5**	1	**11**	18
	(808)	(16)	**(737)**	-

(1) Net of income tax recovery of 5 and 2 for the three and six months ended June 30, 2012 (2011 - nil and 4 expense), respectively.

(2) Net of income tax expense of 1 and 2 for the three and six months ended June 30, 2012 (2011 - 9 expense and 4 recovery), respectively.

(3) Net of income tax of nil for the three and six months ended June 30, 2012 (2011 - nil), respectively.

(4) Net of income tax expense of 6 and 23 for the three and six months ended June 30, 2012 (2011 - 11 and 88 expense), respectively.

(5) Net of income tax recovery of 5 and 8 for the three and six months ended June 30, 2012 (2011 - 7 and 6 recovery), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**June 30, 2012**	Dec. 31, 2011
Cash and cash equivalents *(Note 13)*	**61**	49
Accounts receivable	**465**	541
Current portion of finance lease receivable	**3**	3
Collateral paid *(Note 12)*	**36**	45
Prepaid expenses	**21**	8
Risk management assets *(Notes 11 and 12)*	**287**	391
Inventory *(Note 14)*	**99**	85
Income taxes receivable *(Note 15)*	**16**	2
	988	1,124
Investments *(Note 8)*	**189**	193
Long-term receivable *(Note 16)*	**19**	18
Finance lease receivable	**41**	42
Property, plant, and equipment *(Note 17)*		
Cost	**11,186**	11,386
Accumulated depreciation	**(4,295)**	(4,115)
	6,891	7,271
Goodwill	**447**	447
Intangible assets	**279**	276
Deferred income tax assets	**50**	176
Risk management assets *(Notes 11 and 12)*	**89**	99
Other assets *(Note 18)*	**90**	90
Total assets	**9,083**	9,736
Accounts payable and accrued liabilities	**613**	463
Decommissioning and other provisions *(Note 19)*	**60**	99
Collateral received *(Note 12)*	**12**	16
Risk management liabilities *(Notes 11 and 12)*	**187**	208
Income taxes payable	**7**	22
Dividends payable *(Notes 12, 22 and 23)*	**67**	67
Current portion of long-term debt *(Notes 11, 12 and 20)*	**320**	316
	1,266	1,191
Long-term debt *(Notes 11, 12 and 20)*	**3,955**	3,721
Decommissioning and other provisions *(Note 19)*	**260**	283
Deferred income tax liabilities	**412**	491
Risk management liabilities *(Notes 11 and 12)*	**112**	142
Deferred credits and other long-term liabilities *(Note 21)*	**303**	281
Equity		
Common shares *(Note 22)*	**2,335**	2,273
Preferred shares *(Note 23)*	**562**	562
Contributed surplus	**9**	9
Retained earnings (deficit)	**(312)**	527
Accumulated other comprehensive loss *(Note 24)*	**(155)**	(102)
Equity attributable to shareholders	**2,439**	3,269
Non-controlling interests	**336**	358
Total equity	**2,775**	3,627
Total liabilities and equity	**9,083**	9,736

Contingencies *(Note 25)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

6 months ended June 30, 2012

Unaudited	Common shares	Preferred shares	Contributed surplus	Retained earnings (deficit)	Accumulated other comprehensive loss [1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2011	2,273	562	9	527	(102)	3,269	358	**3,627**
Net earnings (loss)	-	-	-	(695)	-	(695)	18	**(677)**
Other comprehensive income (loss):								
Gains on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	2	2	-	**2**
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(31)	(31)	(7)	**(38)**
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(24)	(24)	-	**(24)**
Total comprehensive income (loss)						(748)	11	**(737)**
Common share dividends	-	-	-	(131)	-	(131)	-	**(131)**
Preferred share dividends	-	-	-	(13)	-	(13)	-	**(13)**
Distributions to non-controlling interests	-	-	-	-	-	-	(33)	**(33)**
Common shares issued	62	-	-	-	-	62	-	**62**
Balance, June 30, 2012	**2,335**	**562**	**9**	**(312)**	**(155)**	**2,439**	**336**	**2,775**

6 months ended June 30, 2011

Unaudited	Common shares	Preferred shares	Contributed surplus	Retained earnings	Accumulated other comprehensive loss [1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2010	2,204	293	7	431	185	3,120	431	3,551
Net earnings	-	-	-	223	-	223	20	243
Other comprehensive income (loss):								
Losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(18)	(18)	-	(18)
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(202)	(202)	(2)	(204)
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(21)	(21)	-	(21)
Total comprehensive income (loss)						(18)	18	-
Common share dividends	-	-	-	(65)	-	(65)	-	(65)
Preferred share dividends	-	-	-	(7)	-	(7)	-	(7)
Distributions to non-controlling interests	-	-	-	-	-	-	(65)	(65)
Common shares issued	35	-	-	-	-	35	-	35
Effect of share-based payment plans	-	-	1	-	-	1	-	1
Balance, June 30, 2011	2,239	293	8	582	(56)	3,066	384	3,450

(1) Refer to Note 24 for details on components of, and changes in, Accumulated other comprehensive loss.

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2012**	2011	**2012**	2011
Operating activities				
Net earnings (loss)	**(786)**	22	**(677)**	243
Depreciation and amortization *(Note 27)*	**149**	130	**290**	257
Gain on sale of facilities *(Note 7)*	**-**	(3)	**(3)**	(3)
Accretion of provisions *(Note 19)*	**5**	4	**9**	9
Decommissioning and restoration costs settled *(Note 19)*	**(7)**	(10)	**(13)**	(16)
Deferred income tax expense (recovery) *(Note 10)*	**79**	(15)	**82**	74
Unrealized (gain) loss from risk management activities *(Note 12)*	**94**	55	**25**	(147)
Unrealized foreign exchange loss	**2**	2	**11**	2
Provisions	**(2)**	22	**(2)**	22
Asset impairment charges *(Note 6)*	**365**	9	**365**	9
Sundance Units 1 and 2 impairment charge *(Notes 3 and 6)*	**43**	-	**43**	-
Equity (income) loss, net of distributions received	**5**	(2)	**5**	(2)
Other non-cash items	**(1)**	12	**-**	4
Cash flow from operations before changes in working capital	**(54)**	226	**135**	452
Change in non-cash operating working capital balances *(Note 28)*	**132**	(103)	**126**	(161)
Cash flow from operating activities	**78**	123	**261**	291
Investing activities				
Additions to property, plant, and equipment *(Note 17)*	**(175)**	(104)	**(312)**	(191)
Additions to intangibles	**(12)**	(6)	**(18)**	(11)
Proceeds on sale of property, plant, and equipment	**-**	1	-	2
Proceeds on sale of facilities	**-**	30	**3**	30
Resolution of outstanding tax matters	**-**	1	-	3
Realized losses on financial instruments *(Note 12)*	**(8)**	(4)	**(10)**	(2)
Net decrease in collateral received from counterparties *(Note 12)*	**(3)**	(40)	**(3)**	(56)
Net (increase) decrease in collateral paid to counterparties *(Note 12)*	**15**	-	**9**	(9)
Other	**(2)**	15	**(7)**	15
Change in non-cash investing working capital balances	**10**	21	**(2)**	-
Cash flow used in investing activities	**(175)**	(86)	**(340)**	(219)
Financing activities				
Net increase in borrowings under credit facilities *(Note 20)*	**173**	260	**213**	300
Repayment of long-term debt *(Note 20)*	**(3)**	(228)	**(5)**	(230)
Dividends paid on common shares *(Note 22)*	**(23)**	(48)	**(68)**	(95)
Dividends paid on preferred shares *(Note 23)*	**(6)**	(3)	**(14)**	(7)
Net proceeds on issuance of common shares *(Note 22)*	**1**	-	**1**	1
Distributions paid to subsidiaries' non-controlling interests	**(14)**	(18)	**(33)**	(35)
Decrease in finance lease receivable	**-**	-	**1**	1
Other	**(1)**	(4)	**(4)**	(5)
Cash flow from (used in) financing activities	**127**	(41)	**91**	(70)
Cash flow from (used in) operating, investing, and financing activities	**30**	(4)	**12**	2
Effect of translation on foreign currency cash	**-**	2	-	1
Increase (decrease) in cash and cash equivalents	**30**	(2)	**12**	3
Cash and cash equivalents, beginning of period	**31**	40	**49**	35
Cash and cash equivalents, end of period	**61**	38	**61**	38
Cash income taxes paid (recovered)	**11**	2	**27**	(4)
Cash interest paid	**68**	57	**114**	90

See accompanying notes.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

(Tabular amounts in millions of Canadian dollars, except as otherwise noted)

1. ACCOUNTING POLICIES

A. Basis of Preparation

These unaudited interim condensed consolidated financial statements have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting* using the same accounting policies as those used in TransAlta Corporation's ("TransAlta" or "the Corporation") most recent annual consolidated financial statements. These unaudited interim condensed consolidated financial statements do not include all of the disclosures included in the Corporation's annual consolidated financial statements. Accordingly, these should be read in conjunction with the Corporation's most recent annual consolidated financial statements.

The unaudited interim condensed consolidated financial statements include the accounts of the Corporation and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiary so as to obtain benefits from its activities, generally indicated by ownership of, directly or indirectly, more than one-half of the voting rights.

The unaudited interim condensed consolidated financial statements have been prepared on a historical cost basis, except for certain financial assets and liabilities, which are stated at fair value.

These unaudited interim condensed consolidated financial statements reflect all adjustments which consist of normal recurring adjustments and accruals that are, in the opinion of management, necessary for a fair presentation of results. TransAlta's results are partly seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are ordinarily incurred in the second and third quarters when electricity prices are expected to be lower as electricity prices generally increase in the winter months in the Canadian market.

These unaudited interim condensed consolidated financial statements were authorized for issue by the Board of Directors on July 30, 2012.

B. Use of Estimates

The preparation of these condensed consolidated financial statements in accordance with IFRS requires management to use judgment and make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the period. These estimates are subject to uncertainty. Actual results could differ from these estimates due to factors such as fluctuations in interest rates, foreign exchange rates, inflation and commodity prices, and changes in economic conditions, legislation and regulations. Refer to Note 2(Y) of the 2011 annual consolidated financial statements for a more detailed discussion of the critical accounting judgments and key sources of estimation uncertainty.

2. ACCOUNTING CHANGES

Prior Accounting Changes

On Jan. 1, 2011, the Corporation adopted International Financial Reporting Standards ("IFRS") for publicly accountable enterprises. For information on the impact of the transition to IFRS refer to Note 3 of the Corporation's most recent annual consolidated financial statements.

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. The Corporation will apply these amendments along with the adoption of IFRS 10, 11 and 12 on Jan. 1, 2013.

Additional new or amended accounting standards that have been previously issued by the IASB but are not yet effective, and have not been applied by the Corporation, are as outlined in Note 2(Z) of the 2011 annual consolidated financial statements.

Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

3. SUNDANCE UNITS 1 AND 2 ARBITRATION

On Dec. 16, 2010 and Dec. 19, 2010, Unit 1 and Unit 2, respectively, of the Corporation's Sundance facility were shut down due to conditions observed in the boilers at both units. On Feb. 8, 2011, the Corporation 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, the Corporation 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 Unit 1 and Unit 2 were not economically destroyed and the Corporation 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.

The pre-tax income statement impact of the ruling that has been recorded under the caption "Sundance Units 1 and 2 arbitration" in current earnings is as follows:

Availability incentive penalties	260
Reversal of provision on capacity payments	(64)
Impairment of the units *(Note 6)*	43
Interest	8
Total pre-tax impact [(1)]	**247**

(1) Related income tax impact is a recovery of $63 million

The Corporation will immediately start the work to safely restore the units to service. 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.

4. REVENUES

Several of the Corporation's Power Purchase Arrangements and other long-term contracts meet the criteria of operating leases. Total rental income, including contingent rent, related to these contracts, and reported in "Revenues" in the Condensed Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2012, was $40 million (June 30, 2011 - $37 million), and $82 million (June 30, 2011 - $83 million), respectively.

5. EXPENSES BY NATURE

Expenses classified by nature are as follows:

	3 months ended June 30, 2012		3 months ended June 30, 2011	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**125**	**-**	155	-
Purchased power	**15**	**-**	21	-
Salaries and benefits	**1**	**67**	1	68
Depreciation	**10**	**-**	10	-
Other operating expenses	**-**	**64**	-	66
Total	**151**	**131**	187	134

	6 months ended June 30, 2012		6 months ended June 30, 2011	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**264**	**-**	307	-
Purchased power	**52**	**-**	68	-
Salaries and benefits	**2**	**132**	2	138
Depreciation	**20**	**-**	20	-
Other operating expenses	**-**	**126**	-	124
Total	**338**	**258**	397	262

6. ASSET IMPAIRMENT CHARGES

A. 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 the Corporation's 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 the Corporation 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, the Corporation announced that a long-term power agreement was signed for supply of power from December 2014 until the facility is fully retired in 2025. As a result, the Corporation was able to complete an assessment of whether the carrying amount of the Centralia Thermal plant is 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, the Corporation has written off $169 million of deferred income tax assets as it is no longer probable that sufficient taxable income will be available from the Corporation's U.S. operations, which have been impacted by the Centralia Thermal plant impairment, to allow the benefit associated with the deferred income tax assets to be utilized.

B. Sundance Units 1 and 2

During the three and six months ended June 30, 2012, the Corporation recognized a pre-tax impairment charge of $43 million as a result of the conclusion of the Sundance Units 1 and 2 arbitration. The impairment assessment was based on an estimate of fair value less costs to sell, derived from the cash flows expected to result under the provisions of the PPA, and the estimated costs to return the Units to service (See Note 3).

C. Other

During the three months ended June 30, 2012, the Corporation 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.

During the three months ended June 30, 2011, the Corporation completed an impairment assessment based on an estimate of fair value less costs to sell, derived from the long range forecast and prices evidenced in the market place. As a result, the Corporation recorded a pre-tax impairment charge of $9 million on an asset within the renewables fleet that was part of the acquisition of Canadian Hydro, in order to write this asset down to its fair value. The impairment loss was included in the Generation segment for the applicable period.

D. Reversals

The impairment charges and the reduction of the deferred tax asset can be reversed in future periods if the forecasted cash flows to be generated by the impacted plants, and the estimated taxable income to be generated by the Centralia Thermal plant, respectively, improve.

7. DISPOSALS

During the three and six months ended June 30, 2012, the Corporation realized a pre-tax gain of nil and $3 million, respectively, related to the 2011 sale of its biomass facility. The gain resulted from the release of the remaining consideration related to the achievement of the Environmental Attribute Conditions by the purchaser.

On Dec. 20, 2010, TransAlta Cogeneration, L.P., a subsidiary that is owned 50.01 per cent by TransAlta, entered into an agreement for the sale of its 50 per cent interest in the Meridian facility. As a result, the Corporation realized a pre-tax gain of $3 million during the three and six months ended June 30, 2011.

8. INVESTMENTS

The Corporation's investments in jointly controlled entities accounted for using the equity method consists of its investments in CE Generation, LLC and Wailuku River Hydroelectric, L.P.

Summarized information on the results of operations and financial position relating to the Corporation's pro-rata interests in these investments is as follows:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Results of operations				
Revenues	**24**	31	**50**	59
Expenses	**(29)**	(29)	**(55)**	(57)
Proportionate share of net income (loss)	**(5)**	2	**(5)**	2

As at	**June 30, 2012**	Dec. 31, 2011
Financial position		
Current assets	**36**	42
Long-term assets	**419**	423
Current liabilities	**(32)**	(29)
Long-term liabilities	**(220)**	(229)
Non-controlling interests	**(14)**	(14)
Proportionate share of net assets	**189**	193

9. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Interest on debt	**58**	55	**114**	110
Capitalized interest *(Note 17)*	**(1)**	(12)	**(1)**	(23)
Other	**2**	1	**2**	1
Interest expense	**59**	44	**115**	88
Accretion of provisions *(Note 19)*	**5**	4	**9**	9
Net interest expense	**64**	48	**124**	97

The Corporation capitalizes interest during the construction phase of growth capital projects. $1 million was capitalized in 2012 related to New Richmond. Capitalized interest in 2011 relates primarily to Keephills Unit 3.

10. INCOME TAXES

The components of income tax expense (recovery) are as follows:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Current income tax expense (recovery)	**(5)**	9	**8**	12
Adjustments in respect of current income tax of previous periods	**2**	-	**2**	-
Benefit arising from the resolution of outstanding tax matters	**-**	-	**(24)**	-
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(97)**	(15)	**(84)**	74
Deferred income tax expense resulting from changes in tax rates or laws (1)	**7**	-	**7**	-
Deferred income tax expense arising from the write down of deferred tax assets *(Note 6)*	**169**	-	**169**	-
Income tax expense (recovery)	**76**	(6)	**78**	86

(1) Relates to the impact of the Ontario budget bill, which freezes the Ontario general corporate tax rate at 11.5%. The Corporation had been using the previously substantively enacted scheduled reduced tax rate of 10.0%.

Presented in the Condensed Consolidated Statements of Earnings (Loss) as follows:

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Current tax expense (recovery)	**(3)**	9	**(4)**	12
Deferred tax expense (recovery)	**79**	(15)	**82**	74
Income tax expense (recovery)	**76**	(6)	**78**	86

11. FINANCIAL INSTRUMENTS

A. Financial Assets and Liabilities - Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value, or amortized cost.

B. Fair Value of Financial Instruments

The methods used by the Corporation to determine fair values, and descriptions of the fair value hierarchy, are more fully discussed in Note 13(B) of the most recent annual consolidated financial statements.

Energy Trading

Energy trading includes risk management assets and liabilities that are used in the Energy Trading and Generation segments in relation to trading activities and certain contracting activities.

The following table summarizes the key factors impacting the fair value of energy trading risk management assets and liabilities by classification level during the six months ended June 30, 2012:

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2011	-	(90)	(14)	-	287	7	-	197	(7)
Changes attributable to:									
Market price changes on existing contracts	-	10	10	1	20	9	1	30	19
New contracts	-	(1)	-	1	(14)	2	1	(15)	2
Contracts settled	-	8	5	2	(123)	(13)	2	(115)	(8)
Discontinued hedge accounting on certain contracts	-	(28)	-	-	22	6	-	(6)	6
Net risk management assets (liabilities) at June 30, 2012	**-**	**(101)**	**1**	**4**	**192**	**11**	**4**	**91**	**12**
Additional Level III gain (loss) information:									
Change in fair value included in Other Comprehensive Income (Loss) ("OCI")			15			-			15
Realized gain (loss) included in earnings before income taxes			(5)			13			8
Unrealized gain included in earnings before income taxes relating to net assets held at June 30, 2012			-			9			9

To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within the gross margin of the Energy Trading and Generation business segments.

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III energy trading fair values are determined at June 30, 2012 is estimated to be +/- $35 million (Dec. 31, 2011 - +/- $33 million).

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks.

The following table summarizes the key factors impacting the fair value of other risk management assets and liabilities by classification level during the six months ended June 30, 2012:

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management liabilities at Dec. 31, 2011	-	(50)	-	-	-	-	-	(50)	-
Changes attributable to:									
Market price changes on existing contracts	-	24	-	-	-	-	-	24	-
New contracts	-	(38)	-	-	-	-	-	(38)	-
Contracts settled	-	34	-	-	-	-	-	34	-
Discontinued hedge accounting on certain contracts	-	1	-	-	(1)	-	-	-	-
Net risk management liabilities at June 30, 2012	**-**	**(29)**	**-**	**-**	**(1)**	**-**	**-**	**(30)**	**-**

Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value				Total carrying
As at June 30, 2012	Level I	Level II	Level III	Total	value
Long-term debt - June 30, 2012[(1)]	**-**	**4,417**	**-**	**4,417**	**4,275**
Long-term debt - Dec. 31, 2011[(1)]	-	4,324	-	4,324	4,037

(1) Includes current portion.

The book value of other short-term financial assets and liabilities (cash and cash equivalents, accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received, and dividends payable) approximates fair value due to the liquid nature of the asset or liability.

The book value of the net collateral reflected as a long-term receivable approximates fair value as represented by the amount expected to be recovered.

C. Inception Gains and Losses

An inception gain or loss arises due to differences between the fair value of a financial instrument at initial recognition (the transaction price) and the amount calculated through a valuation model. The unrealized gain or loss related to Level III financial instruments is deferred in risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. At June 30, 2012, the unamortized gain is $9 million (Dec. 31, 2011 - $4 million gain).

12. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	June 30, 2012					Dec. 31, 2011
	Net investment hedges	**Cash flow hedges**	**Fair value hedges**	**Not designated as a hedge**	**Total**	Total
Risk management assets						
Energy trading						
Current	-	5	-	280	285	390
Long-term	-	2	-	55	57	73
Total energy trading risk management assets	-	7	-	335	342	463
Other						
Current	1	-	-	1	2	1
Long-term	-	5	27	-	32	26
Total other risk management assets	1	5	27	1	34	27
Risk management liabilities						
Energy trading						
Current	-	25	-	114	139	167
Long-term	-	82	-	14	96	106
Total energy trading risk management liabilities	-	107	-	128	235	273
Other						
Current	2	44	-	2	48	41
Long-term	-	16	-	-	16	36
Total other risk management liabilities	2	60	-	2	64	77
Net energy trading risk management assets (liabilities)	**-**	**(100)**	**-**	**207**	**107**	190
Net other risk management assets (liabilities)	**(1)**	**(55)**	**27**	**(1)**	**(30)**	(50)
Net total risk management assets (liabilities)	**(1)**	**(155)**	**27**	**206**	**77**	140

Additional information on derivative instruments has been presented on a net basis below.

I. Hedges

a. Net Investment Hedges

The Corporation hedges its net investment in foreign operations with U.S. denominated borrowings, cross-currency interest rate swaps, and foreign currency forward contracts.

During the three months ended June 30, 2012, the Corporation de-designated $300 million of borrowings under a U.S. dollar denominated credit facility and U.S.$60 million of foreign currency forward contracts from its net investment hedges due to a reduction in its investment in foreign operations arising from the Centralia Thermal plant impairment. The cumulative net foreign exchange gains (losses) related to these hedges up to the date of de-designation will remain in OCI until a disposal of the related U.S. foreign operation occurs. The Corporation's remaining net investment hedges are comprised of U.S. dollar denominated long-term debt with a face value of U.S.$820 million (Dec. 31, 2011 - U.S.$820 million) and the following foreign currency forward contracts:

As at	June 30, 2012			Dec. 31, 2011			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Currency Forward Contracts							
AUD170	**CAD173**	**(1)**	**2012**	AUD185	CAD184	(4)	2012
-	-	-	-	USD135	CAD138	-	2012

b. Cash Flow Hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at June 30, 2012, are as follows:

As at	June 30, 2012		Dec. 31, 2011	
Type (Thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**4,007**	**1**	7,817	4
Natural gas *(GJ)*	**971**	**38,921**	2,032	39,022
Oil *(gallons)*	**-**	**-**	-	6,300

During the three and six months ended June 30, 2012, unrealized pre-tax gains of nil (June 30, 2011 - nil) and $75 million (June 30, 2011 - $204 million gain), respectively, related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from Accumulated Other Comprehensive Income (Loss) ("AOCI") and recognized in earnings. 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.

During 2012, the Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at June 30, 2012, cumulative gains of $15 million will continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur.

ii. Foreign Currency Rate Risk Management

The Corporation uses foreign exchange forward contracts to hedge a portion of its future foreign denominated receipts and expenditures and to manage foreign exchange exposure on debt not designated as a net investment hedge, and cross-currency swaps to manage foreign exchange exposures on foreign denominated debt.

As at		**June 30, 2012**		Dec. 31, 2011			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Exchange Forward Contracts - foreign denominated receipts/expenditures							
CAD255	**USD238**	**(3)**	**2012-2017**	CAD250	USD233	(8)	2012-2017
USD5	**CAD5**	**-**	**2012**	USD8	CAD8	-	2012
CAD80	**EUR62**	**(1)**	**2012**	CAD103	EUR74	(6)	2012
Foreign Exchange Forward Contracts - foreign denominated debt							
CAD312	**USD300**	**(2)**	**2012**	CAD312	USD300	(5)	2012
CAD314	**USD300**	**(2)**	**2013**	CAD314	USD300	(5)	2013
CAD308	**USD300**	**4**	**2013**	-	-	-	-
Cross-Currency Swaps - foreign denominated debt							
CAD530	**USD500**	**(10)**	**2015**	CAD530	USD500	(22)	2015

iii. Interest Rate Risk Management

The Corporation has outstanding forward start interest rate swaps with fixed rates ranging from 3.07 per cent to 3.75 per cent (Dec. 31, 2011 – 2.75 per cent to 3.43 per cent). Forward start interest rate swaps are used to offset the variability in cash flows resulting from anticipated issuances of long-term debt.

As at	**June 30, 2012**		Dec. 31, 2011		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
USD300	**(41)**	**2013**	USD300	(25)	2012

iv. Cash Flow Hedge Impacts

The following tables summarize the impacts of cash flow hedges:

3 months ended June 30, 2012

		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**(4)**	Revenue	**(6)**	Revenue	**-**
Foreign exchange forwards on project hedges	**5**	Property, plant, and equipment	**-**	Foreign exchange (gain) loss	**-**
Foreign exchange forwards on U.S. debt hedges	**22**	Foreign exchange (gain) loss	**-**	Foreign exchange (gain) loss	**-**
Cross-currency swaps	**17**	Foreign exchange (gain) loss	**(41)**	Foreign exchange (gain) loss	**-**
Forward start interest rate swaps	**(21)**	Interest expense	**2**	Interest expense	**-**
OCI impact	**19**	**OCI impact**	**(45)**	**Net earnings impact**	**-**

3 months ended June 30, 2011

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	20	Revenue	(34)	Revenue	-
Foreign exchange forwards on project hedges	(2)	Property, plant, and equipment	-	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt hedges	(1)	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Cross-currency swaps	-	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Forward start interest rate swaps	-	Interest expense	1	Interest expense	-
OCI impact	17	OCI impact	(33)	Net earnings impact	-

6 months ended June 30, 2012

		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**1**	Revenue	**10**	Revenue	**(75)**
Foreign exchange forwards on project hedges	**3**	Property, plant, and equipment	**1**	Foreign exchange (gain) loss	**-**
Foreign exchange forwards on U.S. debt hedges	**11**	Foreign exchange (gain) loss	**-**	Foreign exchange (gain) loss	**-**
Cross-currency swaps	**12**	Foreign exchange (gain) loss	**(8)**	Foreign exchange (gain) loss	**-**
Forward start interest rate swaps	**(16)**	Interest expense	**2**	Interest expense	**-**
OCI impact	**11**	**OCI impact**	**5**	**Net earnings impact**	**(75)**

6 months ended June 30, 2011					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(16)	Revenue	(72)	Revenue	(204)
Foreign exchange forwards on project hedges	(5)	Property, plant, and equipment	-	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt hedges	(19)	Foreign exchange (gain) loss	33	Foreign exchange (gain) loss	-
Cross-currency swaps	(14)	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
Forward start interest rate swaps	-	Interest expense	1	Interest expense	-
OCI impact	(54)	OCI impact	(38)	Net earnings impact	(204)

Over the next 12 months, the Corporation estimates that $8 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will vary based on changes in these factors. In addition, it is the Corporation's intent to settle a substantial portion of the cash flow hedges by physical delivery of the underlying commodity, resulting in gross settlement at the contract price.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent, to floating rate debt through interest rate swaps as outlined below:

As at	June 30, 2012		Dec. 31, 2011		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset	Maturity
USD150	**27**	**2018**	USD150	25	2018

Including the interest rate swaps above, 28 per cent of the Corporation's debt as at June 30, 2012 is subject to floating interest rates (Dec. 31, 2011 - 23 per cent).

ii. Fair Value Hedge Impacts

During the three and six months ended June 30, 2012 and 2011, there was no ineffectiveness on fair value hedges.

II. Non-Hedges

The Corporation enters into various derivative transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Energy Trading Risk Management Non-Hedge Derivatives

As at	June 30, 2012		Dec. 31, 2011	
Type (Thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**63,364**	**54,962**	56,374	47,133
Natural gas *(GJ)*	**2,214,520**	**2,196,861**	1,007,959	1,030,710
Transmission *(MWh)*	**-**	**2,117**	-	2,908
Oil *(gallons)*	**-**	**6,174**	-	6,552

b. Other Non-Hedge Derivatives

As at	June 30, 2012			Dec. 31, 2011			
Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Exchange Forward Contracts							
CAD2	**AUD3**	**-**	**2012**	CAD37	AUD36	-	2012
USD15	**CAD15**	**-**	**2012**	CAD19	USD19	-	2012
CAD1	**USD-**	**(1)**	**2012**	-	-	-	-

c. Total Return Swaps

The Corporation also has certain compensation and deferred share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

d. Non-Hedge Impacts

For the three and six months ended June 30, 2012, the Corporation recognized net unrealized losses of $63 million (June 30, 2011 - gain of $16 million) and $59 million (June 30, 2011 - gain of $20 million), respectively, related to commodity derivatives.

For the three months ended June 30, 2012, a loss of $2 million (June 30, 2011 - nil) related to foreign exchange derivatives was recognized and is comprised of a net unrealized gain of $1 million (June 30, 2011 - $1 million loss) and a net realized loss of $3 million (June 30, 2011 - $1 million gain). For the six months ended June 30, 2012, a loss of $2 million (June 30, 2011 - $4 million loss) was recognized and is comprised of a net unrealized gain of nil (June 30, 2011 - $2 million gain) and a net realized loss of $2 million (June 30, 2011 - $6 million loss).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of risks arising from financial instruments, which are also more fully discussed in Note 14(B) of the 2011 annual consolidated financial statements.

I. Market Risk

a. Commodity Price Risk

i. Commodity Price Risk - Proprietary Trading

The Corporation's Energy Trading segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information. Value at Risk ("VaR") is the most commonly used metric employed to track and manage the market risk associated with trading positions. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach.

VaR at June 30, 2012 associated with the Corporation's proprietary energy trading activities was $5 million (Dec. 31, 2011 - $5 million).

ii. Commodity Price Risk - Generation

The Generation segment utilizes various commodity contracts to manage the commodity price risk associated with its electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. VaR at June 30, 2012 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $4 million (Dec. 31, 2011 - $5 million). VaR at June 30, 2012 associated with positions and economic hedges that do not meet hedge accounting requirements was $12 million (Dec. 31, 2011 - $9 million).

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate due to changes in market interest rates.

The possible effect on net earnings and OCI, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and interest rate derivatives, outstanding as at the date of the Statement of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 50 basis point (June 30, 2011 - 50 basis point) increase or decrease is a reasonable potential change in market interest rates over the next quarter.

	6 months ended June 30			
	2012		2011	
	Net earnings increase(1)	**OCI loss(1)**	Net earnings increase(1)	OCI loss(1)
50 basis point change	**2**	**(5)**	2	-

(1) *This calculation assumes a decrease in market interest rates. An increase would have the opposite effect.*

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the Euro, and the U.S. and Australian dollars, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations, and the acquisition of equipment and services from foreign suppliers.

The possible effect on net earnings and OCI due to changes in foreign exchange rates associated with financial instruments outstanding as at the date of the Statement of Financial Position, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average six cent (June 30, 2011 - six cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

	6 months ended June 30			
	2012		2011	
Currency	**Net earnings decrease(1)**	**OCI gain(1), (2)**	Net earnings decrease(1)	OCI gain(1), (2)
USD	**(2)**	**11**	(2)	11
AUD	**(1)**	**-**	(1)	-
EUR	**-**	**3**	-	2
Total	**(3)**	**14**	(3)	13

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist.

At June 30, 2012, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding. The Corporation has evaluated the risk of default related to this counterparty to be minimal.

The Corporation's maximum exposure to credit risk at June 30, 2012, without taking into account collateral held or right of set-off, is represented by the carrying amounts of accounts receivable and risk management assets as per the Condensed Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one counterparty for commodity trading operations and hedging, excluding the California market receivables (Refer to Note 32 of the 2011 annual consolidated financial statements) and including the fair value of open trading positions, net of any collateral held, at June 30, 2012 was $35 million (Dec. 31, 2011 - $38 million).

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the distribution, by credit rating, of certain financial assets as at June 30, 2012:

(Per cent)	Investment grade	Non-investment grade	Total
Accounts receivable	96	4	**100**
Risk management assets	97	3	**100**

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2012	2013	2014	2015	2016	2017 and thereafter	Total
Accounts payable and accrued liabilities	613	-	-	-	-	-	613
Collateral received	12	-	-	-	-	-	12
Debt[1]	315	630	209	673	742	1,689	4,258
Energy trading risk management (assets) liabilities	(105)	(36)	(16)	15	13	22	(107)
Other risk management (assets) liabilities	5	40	1	11	-	(27)	30
Interest on long-term debt	107	198	171	139	122	846	1,583
Dividends payable	67	-	-	-	-	-	67
Total	**1,014**	**832**	**365**	**838**	**877**	**2,530**	**6,456**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2013 and 2016.

C. Collateral

I. Financial Assets Provided as Collateral

At June 30, 2012, the Corporation provided $36 million (Dec. 31, 2011 - $45 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At June 30, 2012, the Corporation received $12 million (Dec. 31, 2011 - $16 million) in cash collateral associated with counterparty obligations.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt to fall below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at June 30, 2012, the Corporation had posted collateral of $48 million (Dec. 31, 2011 - $62 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, including a credit rating downgrade to below investment grade, which if triggered would result in the Corporation having to post an additional $82 million of collateral to its counterparties based upon the value of the derivatives at June 30, 2012.

13. RESTRICTED CASH

The Corporation has $29 million of cash and cash equivalents at June 30, 2012 (Dec. 31, 2011 - $17 million) that is not available for general use, all of which relates to Project Pioneer.

14. INVENTORY

Inventory held in the normal course of business includes coal, emission credits, and natural gas, and is valued at the lower of cost and net realizable value. Inventory held for Energy Trading, which also includes natural gas, is valued at fair value less costs to sell.

The classifications are as follows:

As at	June 30, 2012	Dec. 31, 2011
Coal	**93**	78
Natural gas	**4**	5
Purchased emission credits	**2**	2
Total	**99**	85

During the three and six months ended June 30, 2012, coal inventory at the Corporation's Centralia Thermal plant was written down by $8 million (June 30, 2011 - nil) and $42 million (June 30, 2011 - nil), respectively, to its net realizable value.

15. INCOME TAXES RECEIVABLE

In 2008, the Corporation was reassessed by taxation authorities in Canada relating to the sale of its previously operated Transmission Business, requiring the Corporation to pay $49 million in taxes and interest. The Corporation challenged this reassessment. During 2010, a decision from the Tax Court of Canada was received that allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta filed an appeal with the Federal Court in 2010 to pursue the remaining $11 million. The appeal decision from the Federal Court was received on Jan. 20, 2012, and the ruling was in TransAlta's favour. The Crown had 60 days from the date of judgment to appeal the decision. No appeal was filed by the Crown, and TransAlta expects to receive $11 million in 2012.

16. LONG-TERM RECEIVABLE

In 2011, TransAlta had net collateral of approximately U.S.$36 million with MF Global Inc. at the time a trustee has been appointed to take control of, and liquidate the assets of MF Global Inc. and return client collateral. Due to the uncertainty of collection, TransAlta recognized a U.S.$18 million reserve in 2011 against the collateral that had been posted with MF Global Inc.

17. PROPERTY, PLANT, AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant, and equipment ("PP&E") is as follows:

	Land	Thermal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other	Total
As at Dec. 31, 2011	74	3,153	1,041	2,057	534	196	216	7,271
Additions	-	1	-	-	-	306	5	312
Depreciation	-	(140)	(47)	(44)	(19)	-	(6)	(256)
Asset impairment charges	-	(378)	-	(18)	(12)	-	-	(408)
Revisions and additions to decommissioning and restoration costs	-	(8)	(2)	(4)	(3)	-	-	(17)
Retirement of assets	-	(15)	-	(1)	-	-	-	(16)
Change in foreign exchange rates	-	7	-	-	1	-	-	8
Transfers	-	202	4	20	6	(245)	10	(3)
As at June 30, 2012	**74**	**2,822**	**996**	**2,010**	**507**	**257**	**225**	**6,891**

During the three and six months ended June 30, 2012, the Corporation capitalized $1 million (June 30, 2011 - $12 million and $23 million) of interest to PP&E at a weighted average rate of 5.32 per cent and 5.34 per cent (June 30, 2011 - 5.44 and 5.28 per cent), respectively.

During the three months ended June 30, 2011, the Corporation wrote down certain capital spares to their estimated recoverable amount, resulting in a $4 million pre-tax increase in the depreciation expense of the Generation segment.

18. OTHER ASSETS

The components of other assets are as follows:

As at	June 30, 2012	Dec. 31, 2011
Deferred license fees	**21**	22
Project development costs	**36**	33
Deferred service costs	**19**	18
Keephills Unit 3 transmission deposit	**7**	8
Other	**7**	9
Total other assets	**90**	90

19. DECOMMISSIONING AND OTHER PROVISIONS

The change in decommissioning and other provision balances is outlined below:

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2011	301	81	382
Liabilities incurred in period	1	22	23
Liabilities settled in period	(13)	(1)	(14)
Accretion	8	1	9
Revisions in estimated cash flows	1	2	3
Revisions in discount rates	(18)	-	(18)
Reversals	-	(66)	(66)
Change in foreign exchange rates	1	-	1
	281	39	320
Less: current portion	**28**	**32**	**60**
Balance, June 30, 2012	**253**	**7**	**260**

20. LONG-TERM DEBT

The amounts outstanding are as follows:

As at	**June 30, 2012**			Dec. 31, 2011		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**1,023**	**1,023**	**2.2%**	806	806	2.1%
Debentures	**836**	**851**	**6.6%**	833	851	6.6%
Senior notes[3]	**2,001**	**1,963**	**6.0%**	1,979	1,940	6.0%
Non-recourse[4]	**375**	**381**	**5.9%**	375	382	5.9%
Other	**40**	**40**	**6.5%**	44	44	6.6%
	4,275	**4,258**		4,037	4,023	
Less: recourse current portion	**(318)**	**(318)**		(314)	(314)	
Less: non-recourse current portion	**(2)**	**(2)**		(2)	(2)	
Total long-term debt	**3,955**	**3,938**		3,721	3,707	

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
Includes U.S.$300 million at June 30, 2012 (Dec. 31, 2011 - U.S.$300 million).
(3) U.S. face value at June 30, 2012 - U.S.$1,900 million (Dec. 31, 2011 - U.S.$1,900 million).
(4) Includes U.S.$20 million at June 30, 2012 (Dec. 31, 2011 - U.S.$20 million).

TransAlta has a total of $2.4 billion (Dec. 31, 2011 - $2.0 billion) of committed credit facilities, of which $1.1 billion (Dec. 31, 2011 - $0.9 billion) is not drawn, and is available as of June 30, 2012, subject to customary borrowing conditions. In addition to the $1.1 billion available under the credit facilities, TransAlta also has $32 million of available cash and cash equivalents.

In April 2012, the Corporation completed a renewal of its $1.5 billion committed syndicated credit facility, and extended the maturity from 2015 to 2016.

21. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

The components of deferred credits and other long-term liabilities are as follows:

As at	June 30, 2012	Dec. 31, 2011
Deferred coal revenues	**52**	52
Present value of defined benefit obligations	**221**	190
Long-term incentive accruals	**13**	18
Other	**17**	21
Total deferred credits and other long-term liabilities	**303**	281

Deferred coal revenues consist of payments received from Keephills 3 Limited Partnership for future coal deliveries. Since commercial operations of Keephills Unit 3 began on Sept. 1, 2011, these amounts are being amortized into revenue over the life of the coal supply agreement.

22. COMMON SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

At June 30, 2012, the Corporation had 227.0 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. During the three months ended June 30, 2012, 2.4 million (June 30, 2011 - 0.8 million) common shares were issued for $43 million (June 30, 2011 - $17 million), of which 2.3 million (June 30, 2011 - 0.8 million) were issued for $42 million (June 30, 2011 - $16 million) for dividends reinvested under the terms of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan") and 0.1 million (June 30, 2011 - a nominal number) were issued for $1 million (June 30, 2011 - $1 million). During the six months ended June 30, 2012, 3.4 million (June 30, 2011 - 1.7 million) common shares were issued for $64 million (June 30, 2011 - $35 million), of which 3.3 million (June 30, 2011 - 1.6 million) were issued for $62 million (June 30, 2011 - $33 million) for dividends reinvested under the terms of the Plan and 0.1 million (June 30, 2011 - 0.1 million) were issued for $2 million (June 30, 2011 - $2 million).

B. Share Based Payment Plans

The Corporation issues common shares under share-based payment plans, such as the Stock Option Plans and the Performance Share Ownership Plan ("PSOP"), which are more fully described in Note 27 of the Corporation's most recent annual consolidated financial statements. During the six months ended June 30, 2012, a nominal number of employee stock options were exercised, expired or were cancelled (June 30, 2011 - 0.4 million). During the six months ended June 30, 2012, 1.7 million (June 30, 2011 - 1.4 million) PSOP units were granted and a nominal number (June 30, 2011 - nil) were awarded and exchanged for common shares.

C. Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan

During February 2012, the Corporation added a Premium Dividend™ component to its Dividend Reinvestment and Share Purchase plan. The amended and restated plan is called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan, and is more fully discussed in Note 24(C) of the most recent annual consolidated financial statements.

Of the dividend that was payable on July 1, 2012, 72 per cent was settled through the dividend reinvestment option under the Plan.

D. Dividends

The following tables summarize the common share dividends declared in 2011 and 2012:

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Jan. 25, 2012	Apr. 1, 2012	0.29	65	23	42
Apr. 25, 2012	July 1, 2012	0.29	66	18	48
Total		**0.58**	**131**		

Date declared	Payment date	Dividend per share *($)*	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Apr. 28, 2011	July 1, 2011	0.29	64	48	16
July 27, 2011	Oct. 1, 2011	0.29	65	48	17
Oct. 27, 2011	Jan. 1, 2012	0.29	65	45	20
Total		**0.87**	**194**		

There have been no other transactions involving common shares between the reporting date and the date of completion of these condensed consolidated financial statements.

23. PREFERRED SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of first preferred shares, and the Board of Directors is authorized to determine the rights, privileges, restrictions and conditions attaching to such shares, subject to certain limitations. At June 30, 2012, the Corporation had 12.0 million Series A (Dec. 31, 2011 - 12.0 million), and 11.0 million Series C (Dec. 31, 2011 - 11.0 million), Cumulative Redeemable Rate Reset First Preferred shares, respectively, issued and outstanding.

B. Dividends

The following tables summarize the preferred share dividends declared in 2011 and 2012:

Series A Cumulative Redeemable Rate Reset First Preferred Shares:

Date declared	Payment date	Dividend per share *($)*	Total dividends
Jan. 25, 2012	March 31, 2012	0.2875	3
Apr. 25, 2012	June 30, 2012	0.2875	4
		0.575	**7**

Date declared	Payment date	Dividend per share *($)*	Total dividends
Apr. 28, 2011	June 30, 2011	0.2875	3
July 27, 2011	Sept. 30, 2011	0.2875	4
Oct. 27, 2011	Dec. 31, 2011	0.2875	4
Total		0.8625	11

Series C Cumulative Redeemable Rate Reset First Preferred Shares:

Date declared	**Payment date**	**Dividend per share** *($)*	**Total dividends**
Jan. 25, 2012 (1)	March 31, 2012	0.3844	4
Apr. 25, 2012	June 30, 2012	0.2875	3
		0.6719	**7**

(1) Includes dividends of $0.0969 per share for the period from Nov. 29, 2011 to Dec. 31, 2011.

24. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The components of, and changes in, AOCI are presented below:

	2012	2011
Currency translation adjustment		
Opening balance	**(28)**	(27)
Gains (losses) on translating net assets of foreign operations	**13**	(44)
Gains (losses) on financial instruments designated as hedges of foreign operations (1)	**(11)**	26
Balance, June 30	**(26)**	(45)
Cash flow hedges		
Opening balance	**(28)**	232
Gains (losses) on derivatives designated as cash flow hedges, net of tax (2)	**16**	(48)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax (3)	**1**	-
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax (4)	**(48)**	(154)
Balance, June 30	**(59)**	30
Employee future benefits		
Opening balance	**(46)**	(20)
Net actuarial losses on defined benefit plans, net of tax (5)	**(24)**	(21)
Balance, June 30	**(70)**	(41)
Accumulated other comprehensive loss	**(155)**	(56)

(1) Net of income tax recovery of 2 for the six months ended June 30, 2012 (2011 - 4 expense).

(2) Net of income tax expense of 2 for the six months ended June 30, 2012 (2011 - 4 recovery).

(3) Net of income taxes of nil for the six months ended June 30, 2012 (2011 - nil).

(4) Net of income tax expense of 23 for the six months ended June 30, 2012 (2011 - 88 expense).

(5) Net of income tax recovery of 8 for the three months ended June 30, 2012 (2011 - 6 recovery).

25. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

26. GUARANTEES - LETTERS OF CREDIT

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at June 30, 2012 was $297 million (Dec. 31, 2011 - $328 million) with no (Dec. 31, 2011 - nil) amounts exercised by third parties under these arrangements.

27. SEGMENT DISCLOSURES

A. Reported Segment Earnings (Loss)

Each business segment assumes responsibility for its operating results to operating income.

3 months ended June 30, 2012	Generation	Energy Trading	Corporate	Total
Revenues	418	(11)	-	407
Fuel and purchased power	151	-	-	151
Gross margin	267	(11)	-	256
Operations, maintenance and administration	105	6	20	131
Depreciation and amortization	134	-	5	139
Asset impairment charges	365	-	-	365
Inventory writedown	8	-	-	8
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	4	(4)	-	-
Operating loss	(356)	(13)	(25)	(394)
Finance lease income	2	-	-	2
Equity loss	(5)	-	-	(5)
Sundance Units 1 and 2 arbitration				(247)
Other income				1
Foreign exchange loss				(3)
Net interest expense				(64)
Loss before income taxes				(710)

3 months ended June 30, 2011	Generation	Energy Trading	Corporate	Total
Revenues	478	37	-	515
Fuel and purchased power	187	-	-	187
Gross margin	291	37	-	328
Operations, maintenance and administration	109	10	15	134
Depreciation and amortization	113	1	6	120
Asset impairment charges	9	-	-	9
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	2	(2)	-	-
Operating income (loss)	51	28	(21)	58
Finance lease income	2	-	-	2
Equity income	2	-	-	2
Gain on sale of facilities				3
Other income				1
Foreign exchange loss				(2)
Net interest expense				(48)
Earnings before income taxes				16

6 months ended June 30, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,057**	**6**	**-**	**1,063**
Fuel and purchased power	**338**	**-**	**-**	**338**
Gross margin	**719**	**6**	**-**	**725**
Operations, maintenance and administration	**203**	**13**	**42**	**258**
Depreciation and amortization	**258**	**-**	**10**	**268**
Asset impairment charges	**365**	**-**	**-**	**365**
Inventory writedown	**42**	**-**	**-**	**42**
Taxes, other than income taxes	**14**	**-**	**-**	**14**
Intersegment cost allocation	**7**	**(7)**	**-**	**-**
Operating loss	**(170)**	**-**	**(52)**	**(222)**
Finance lease income	**4**	**-**	**-**	**4**
Equity loss	**(5)**	**-**	**-**	**(5)**
Sundance Units 1 and 2 arbitration				**(247)**
Gain on sale of facilities				**3**
Other income				**1**
Foreign exchange loss				**(9)**
Net interest expense				**(124)**
Loss before income taxes				**(599)**

6 months ended June 30, 2011	Generation	Energy Trading	Corporate	Total
Revenues	1,281	52	-	1,333
Fuel and purchased power	397	-	-	397
	884	52	-	936
Operations, maintenance and administration	209	15	38	262
Depreciation and amortization	222	1	11	234
Asset impairment charges	9	-	-	9
Taxes, other than income taxes	14	-	-	14
Intersegment cost allocation	4	(4)	-	-
Operating income (loss)	426	40	(49)	417
Finance lease income	4	-	-	4
Equity income	2	-	-	2
Gain on sale of facilities	3	-	-	3
Other income				1
Foreign exchange loss				(1)
Net interest expense				(97)
Earnings before income taxes				329

Included in the Generation Segment results for the three and six months ended June 30, 2012 is $5 million (June 30, 2011 - $6 million) and $13 million (June 30, 2011 - $12 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

B. Selected Condensed Consolidated Statements of Financial Position Information

Total segment assets	**Generation**	**Energy Trading**	**Corporate**	**Total**
June 30, 2012	**8,530**	**288**	**265**	**9,083**
Dec. 31, 2011	**8,983**	**394**	**359**	**9,736**

C. Depreciation and Amortization on the Condensed Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Condensed Consolidated Statements of Earnings and the Condensed Consolidated Statements of Cash Flows is presented below:

	3 months ended June 30		**6 months ended June 30**	
	2012	2011	**2012**	2011
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**139**	120	**268**	234
Depreciation included in fuel and purchased power	**10**	10	**20**	20
Other	**-**	-	**2**	3
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**149**	130	**290**	257

28. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended June 30		6 months ended June 30	
	2012	2011	**2012**	2011
Source (use) of cash:				
Accounts receivable	**(26)**	(106)	**78**	3
Prepaid expenses	**2**	6	**(13)**	(7)
Income taxes receivable	**-**	12	**(14)**	18
Inventory	**(13)**	(25)	**(15)**	(58)
Accounts payable and accrued liabilities	**237**	2	**147**	(131)
Decommissioning and other provisions	**(53)**	12	**(41)**	18
Income taxes payable	**(15)**	(4)	**(16)**	(4)
Change in non-cash operating working capital	**132**	(103)	**126**	(161)

SUPPLEMENTAL INFORMATION

		June 30, 2012	Dec. 31, 2011
Closing market price (TSX) ($)		**17.25**	21.02
Price range for the last 12 months (TSX) ($)	High	**21.37**	23.24
	Low	**16.16**	19.45
Debt to invested capital (%)		**60.5**	52.4
Debt to invested capital excluding non-recourse debt (%)		**58.2**	49.9
Return on equity attributable to common shareholders (%)		**(26.1)**	10.6
Comparable return on equity attributable to common shareholders[1, 2] (%)		**4.6**	8.4
Return on capital employed[1] (%)		**(3.7)**	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)		**33.8**	20.4
Earnings coverage[1] (times)		**(1.3)**	2.7
Dividend payout ratio based on net earnings[1] (%)		**(41.0)**	66.9
Dividend payout ratio based on comparable earnings[1, 2] (%)		**230.1**	84.3
Dividend payout ratio based on funds from operations[1, 2, 3] (%)		**37.4**	24.0
Dividend yield[1] (%)		**6.7**	5.5
Cash flow to debt[1, 3] (%)		**16.8**	20.2
Cash flow to interest coverage[1, 3] (times)		**4.0**	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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