TRANSALTA CORPORATION
FIRST 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 months ended March 31, 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 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 April 25, 2012. Additional information respecting TransAlta, including its Annual Information Form, is available on SEDAR at www.sedar.com.

RESULTS OF OPERATIONS

The results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading, and Corporate. In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant Condensed Consolidated Statements of Earnings and Condensed Consolidated Statements of Financial Position items. While individual line items in the Condensed Consolidated Statements of Financial Position may be impacted by foreign exchange fluctuations, the net impact of the translation of these items relating to foreign operations to our presentation currency is reflected in Accumulated Other Comprehensive (Loss) Income ("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 March 31	
	2012	2011
Availability (%)[1]	**91.7**	90.3
Production (GWh)[1]	**9,441**	10,104
Revenues	**656**	818
Gross margin[2]	**469**	608
Operating income[2]	**172**	359
Comparable operating income[3]	**121**	160
Net earnings attributable to common shareholders	**89**	204
Net earnings per share attributable to common shareholders, basic and diluted	**0.40**	0.92
Comparable earnings per share[3]	**0.20**	0.34
Comparable EBITDA[3]	**261**	287
Funds from operations[3]	**189**	226
Funds from operations per share[3]	**0.84**	1.02
Cash flow from operating activities	**183**	168
Free cash flow[3]	**10**	100
Dividends paid per common share	**0.29**	0.29

As at	**March 31, 2012**	Dec. 31, 2011
Total assets	**9,623**	9,736
Total long-term liabilities	**4,917**	4,918

AVAILABILITY & PRODUCTION

Availability for the three months ended March 31, 2012 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 Power Purchase Arrangement ("PPA") facilities and higher unplanned outages, primarily at Genesee Unit 3.

Production for the three months ended March 31, 2012 decreased 663 gigawatt hours ("GWh") compared to the same period in 2011 due to higher economic dispatching at Centralia Thermal, lower PPA customer demand, higher planned outages at the Alberta coal PPA facilities, and higher unplanned outages, primarily at Genesee Unit 3, partially offset by the commencement of commercial operations of Keephills Unit 3, lower planned and unplanned outages at Centralia Thermal, and higher wind volumes.

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

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

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

NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

The primary factors contributing to the change in net earnings attributable to common shareholders for the three months ended March 31, 2012 are presented below:

	3 months ended March 31
Net earnings attributable to common shareholders, 2011	204
Decrease in Generation gross margins	(38)
Mark-to-market movements - Generation	(103)
Increase in Energy Trading gross margins	2
Increase in depreciation expense	(15)
Increase in gain on sale of facilities	3
Increase in inventory writedown	(34)
Increase in net interest expense	(11)
Decrease in income tax expense	90
Increase in preferred share dividends	(3)
Other	(6)
Net earnings attributable to common shareholders, 2012	**89**

Generation gross margins, excluding the impact of mark-to-market movements, for the three months ended March 31, 2012 decreased compared to the same period in 2011 primarily due to higher planned outages at the Alberta coal PPA facilities, lower hydro margins, higher unplanned outages, primarily at Genesee Unit 3, and unfavourable pricing, partially offset by the commencement of commercial operations of Keephills Unit 3, and higher wind volumes.

Mark-to-market movements decreased for the three months ended March 31, 2012 compared to the same period in 2011 due to the value of certain hedges being deemed ineffective in 2011 compared to a lower amount in 2012.

For the three months ended March 31, 2012, Energy Trading gross margins increased compared to the same period in 2011 principally due to successful trading strategies in the Western U.S. and Eastern regions, partially offset by lower results in Alberta from lower demand due to unseasonably mild weather.

Operations, maintenance, and administration (“OM&A”) costs for the three months ended March 31, 2012 were comparable to the same period in 2011.

For the three months ended March 31, 2012, depreciation expense 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 three months ended March 31, 2012 is due to the release of a contingent provision on the sale of Grande Prairie.

The inventory writedown recorded in the three months ended March 31, 2012 is due to the writedown of coal inventories resulting from de-designation of the hedges at Centralia Thermal and the continued low price environment in the Pacific Northwest.

For the three months ended March 31, 2012, net interest expense increased compared to the same period in 2011 due to lower capitalized interest and higher interest rates, partially offset by lower debt levels.

Income tax expense for the three months ended March 31, 2012 decreased compared to the same period in 2011 due to lower net earnings and the positive resolution of $24 million of certain outstanding tax matters.

The preferred share dividends for the three months ended March 31, 2012 increased compared to the same period 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 months ended March 31, 2012 decreased $37 million compared to the same period in 2011 primarily due to lower net earnings.

Free cash flow for the three months ended March 31, 2012 decreased $90 million compared to the same period in 2011 due to the decrease in funds from operations and higher sustaining capital and productivity expenditures. A significant part of the sustaining capital and productivity expenditures incurred during 2012 relates to more comprehensive maintenance incurred at Keephills Unit 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 March 31, 2012

Centralia Coal Inventory Impairment

During the quarter, we recognized a pre-tax impairment charge of $34 million related to the coal inventory at our Centralia plant. The impairment resulted from the de-designation of the hedges at Centralia Thermal and the continued low price environment in the Pacific Northwest. During the quarter, we de-designated and recognized $85 million of pre-tax gains related to 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 an impairment charge on the coal inventory. The net $51 million impact associated with the hedge de-designation and inventory impairment has been adjusted in calculating earnings on a comparable basis. Please refer to the Non-IFRS Measures section of this MD&A.

MF Global Inc.

During the 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 quarter and our provision of $18 million associated with the $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

Project Pioneer

On April 26, 2012, Project Pioneer’s industry partners announced they will 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.

Sundance Units 1 and 2 Shut Down

On April 9, 2012, arbitration commenced related to the disputed notice of force majeure and termination for destruction under the terms of the PPA. Although no assurance can be given as to the timing or ultimate outcome of these matters, our view continues to be that we expect no material financial impact associated with the shut down to the extent the event meets the termination for destruction criteria under the PPA. Please refer to the Significant Events section of our 2011 Annual Report for additional information regarding the Sundance Units 1 and 2 shut down.

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 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.*

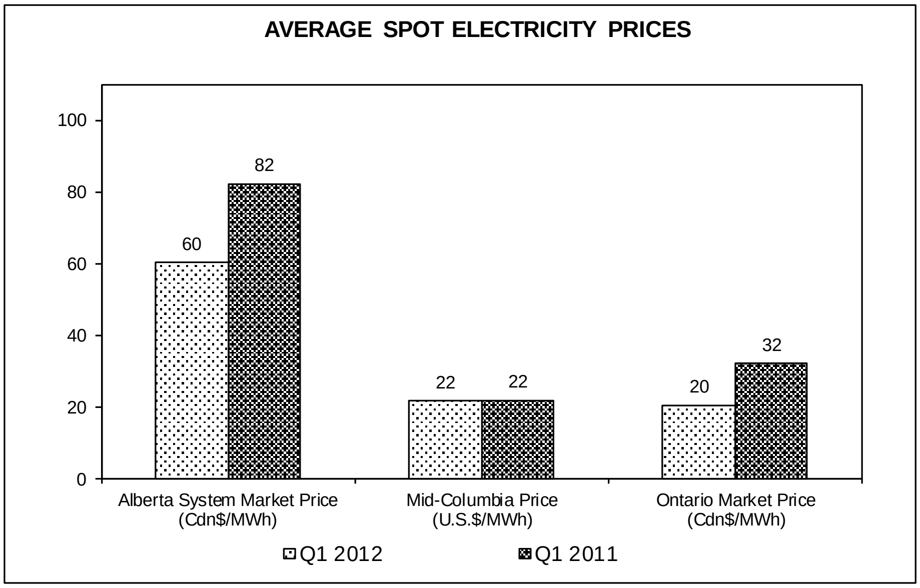
Contracted Cash Flows

During the first quarter of 2012, approximately 90 per cent of our consolidated power portfolio was contracted through the use of PPAs and other long-term contracts. We also enter 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 risk associated with changes in those prices.

The average spot electricity prices for the three months ended March 31, 2012 and 2011 in our three major markets are shown in the following graphs.

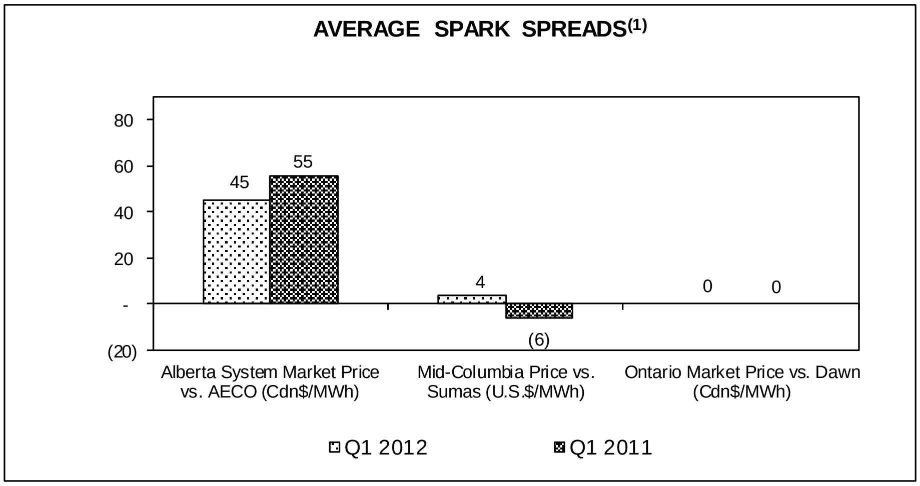


For the three months ended March 31, 2012, average spot prices decreased in Alberta due to unseasonably mild weather and decreases in demand due to heavy oil sand turnaround activity and high wind production. In the Pacific Northwest, average spot prices were comparable to the same period in 2011 with 2011 being negatively impacted by higher than normal hydro production and 2012 being impacted by low gas prices. In Ontario, average spot prices decreased compared to the same period in 2011 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 months ended March 31, 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 March 31, 2012, average spark spreads decreased in Alberta due to lower power prices. In the Pacific Northwest, average spark spreads increased due to lower natural gas prices. In Ontario, spark spreads were comparable to the same period in 2011.

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 March 31, 2012, our generating assets had 8,174 MW of gross generating capacity(1) in operation (7,831 MW net ownership interest) and 129 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 March 31	**Total**	**Comparable adjustments**	**Comparable total(2)**	**Per installed MWh**	Comparable total(2)	Per installed MWh
Revenues	**639**	**(85)**	**554**	**31.03**	604	35.20
Fuel and purchased power	**187**	**-**	**187**	**10.48**	210	12.24
Gross margin	**452**	**(85)**	**367**	**20.55**	394	22.96
Operations, maintenance and administration	**98**	**-**	**98**	**5.49**	100	5.83
Depreciation and amortization	**124**	**-**	**124**	**6.95**	109	6.35
Inventory writedown	**34**	**(34)**	**-**	**-**	-	-
Taxes, other than income taxes	**7**	**-**	**7**	**0.39**	7	0.41
Intersegment cost allocation	**3**	**-**	**3**	**0.17**	2	0.12
Operating income	**186**	**(51)**	**135**	**7.55**	176	10.25
Installed capacity (GWh)	**17,851**		**17,851**		17,157	
Production (GWh)	**8,913**		**8,913**		9,559	
Availability (%)	**91.6**		**91.6**		90.2	

Generation Production and Comparable Gross Margins(2)

Production volumes, comparable revenues(2), fuel and purchased power costs, and comparable gross margins based on geographical regions and fuel types are presented below.

3 months ended March 31, 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	**5,263**	**6,944**	**222**	**93**	**129**	**31.97**	**13.39**	**18.58**
Gas	**704**	**778**	**31**	**6**	**25**	**39.85**	**7.71**	**32.14**
Renewables	**751**	**2,921**	**48**	**3**	**45**	**16.43**	**1.03**	**15.40**
Total Western Canada	**6,718**	**10,643**	**301**	**102**	**199**	**28.28**	**9.58**	**18.70**
Gas	**1,003**	**1,638**	**99**	**43**	**56**	**60.44**	**26.25**	**34.19**
Renewables	**460**	**1,444**	**45**	**2**	**43**	**31.16**	**1.39**	**29.77**
Total Eastern Canada	**1,463**	**3,082**	**144**	**45**	**99**	**46.72**	**14.60**	**32.12**
Coal	**404**	**2,929**	**82**	**32**	**50**	**28.00**	**10.93**	**17.07**
Gas	**328**	**1,197**	**27**	**8**	**19**	**22.56**	**6.68**	**15.88**
Total International	**732**	**4,126**	**109**	**40**	**69**	**26.42**	**9.69**	**16.73**
	8,913	**17,851**	**554**	**187**	**367**	**31.03**	**10.48**	**20.55**

(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.

3 months ended March 31, 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	5,546	6,366	204	59	145	32.05	9.27	22.78
Gas	742	823	38	9	29	46.17	10.94	35.23
Renewables	711	2,840	51	3	48	17.96	1.06	16.90
Total Western Canada	6,999	10,029	293	71	222	29.22	7.08	22.14
Gas	1,006	1,620	117	65	52	72.22	40.12	32.10
Renewables	410	1,428	39	2	37	27.31	1.40	25.91
Total Eastern Canada	1,416	3,048	156	67	89	51.18	21.98	29.20
Coal	816	2,896	125	62	63	43.16	21.41	21.75
Gas	328	1,184	30	10	20	25.34	8.45	16.89
Total International	1,144	4,080	155	72	83	37.99	17.65	20.34
	9,559	17,157	604	210	394	35.20	12.24	22.96

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 months ended March 31, 2012 are presented below:

	3 months ended March 31 (GWh)
Production, 2011	6,999
Lower PPA customer demand	(367)
Higher planned outages at the Alberta coal PPA facilities	(235)
Higher unplanned outages at Genesee Unit 3	(85)
Higher unplanned outages at the Alberta coal PPA facilities	(44)
Lower hydro volumes	(39)
Market curtailments	(22)
Lower production at natural gas-fired facilities	(8)
Commencement of commercial operations of Keephills Unit 3	449
Higher wind volumes	79
Other	(9)
Production, 2012	**6,718**

The primary factors contributing to the change in comparable gross margin for the three months ended March 31, 2012 are presented below:

	3 months ended March 31
Comparable gross margin, 2011	222
Higher planned outages at the Alberta coal PPA facilities	(18)
Higher unplanned outages at the Alberta coal PPA facilities	(6)
Lower hydro margins	(6)
Higher unplanned outages at Genesee Unit 3	(5)
Unfavourable pricing	(6)
Unfavourable coal pricing	(3)
Commencement of commercial operations of Keephills Unit 3	19
Higher wind volumes	3
Other	(1)
Comparable gross margin, 2012	**199**

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 months ended March 31, 2012 are presented below:

	3 months ended March 31 (GWh)
Production, 2011	1,416
Higher wind volumes	58
Unfavourable market conditions at natural gas-fired facilities	(3)
Other	(8)
Production, 2012	**1,463**

The primary factors contributing to the change in gross margin for the three months ended March 31, 2012 are presented below:

	3 months ended March 31
Gross margin, 2011	89
Favourable contracted gas input costs	5
Higher wind volumes	4
Other	1
Gross margin, 2012	**99**

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 months ended March 31, 2012 are presented below:

	3 months ended March 31 (GWh)
Production, 2011	1,144
Higher economic dispatching at Centralia Thermal	(739)
Lower planned and unplanned outages at Centralia Thermal	330
Other	(3)
Production, 2012	**732**

The primary factors contributing to the change in comparable gross margin for the three months ended March 31, 2012 are presented below:

	3 months ended March 31
Comparable gross margin, 2011	83
Unfavourable pricing, including purchased power prices	(20)
Favourable foreign exchange	1
Other	5
Comparable gross margin, 2012	**69**

Operations, Maintenance, and Administration Expense

OM&A costs for the three months ended March 31, 2012 were comparable to the same period in 2011.

Depreciation Expense

The primary factors contributing to the change in depreciation expense for the three months ended March 31, 2012 are presented below:

	3 months ended March 31
Depreciation and amortization expense, 2011	109
Increase in asset base	10
Asset retirements	3
Unfavourable foreign exchange	1
Other	1
Depreciation and amortization expense, 2012	**124**

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 March 31	
	2012	2011
Availability (%)	**102.6**	105.4
Production (GWh)	**137**	119

Availability for the three months ended March 31, 2012 decreased compared to the same periods in 2011 due to seasonal derates due to milder than expected winter temperatures.

Production for the three months ended March 31, 2012 increased by 18 GWh compared to the same period in 2011 due to increased customer demand partially offset by higher unplanned outages.

Finance lease income for the three months ended March 31, 2012 was consistent with the same period in 2011 at $2 million.

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 Generation ("CE Gen"), LLC and Wailuku Hydroelectric, L.P. joint ventures are accounted for under 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 investments accounted for under the equity method:

	3 months ended March 31	
	2012	2011
Availability (%)	**92.9**	90.6
Production (GWh)		
Gas	**91**	125
Renewables	**300**	301
Total production	**391**	426

Availability for the three months ended March 31, 2012 increased compared to the same period in 2011 due to lower planned outages partially offset by higher unplanned outages.

Production for the three months ended March 31, 2012 decreased compared to the same period in 2011 due to unfavourable market conditions and higher unplanned outages, partially offset by lower planned outages.

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 will revert to a pricing clause that will permit the power purchaser to pay their short-run avoided costs ("SRAC") as the price for power. The SRAC is linked with 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 the current fixed energy prices being received.

Please refer to *Note 7* of our audited consolidated financial statements within our 2011 Annual Report and *Note 6* of our interim condensed consolidated financial statements as at and for the three months ended March 31, 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 manages available generating capacity, as well as the fuel and transmission needs, of the Generation Segment by utilizing contracts of various durations for the forward purchase and sale of electricity and for the purchase and sale of natural gas and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. 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 March 31	
	2012	2011
Revenues	**17**	15
Fuel and purchased power	**-**	-
Gross margin	**17**	15
Operations, maintenance, and administration	**7**	5
Intersegment cost allocation	**(3)**	(2)
Operating income	**13**	12

For the three months ended March 31, 2012, Energy Trading gross margins increased compared to the same period in 2011 principally due to successful trading strategies in the Western U.S. and Eastern regions, partially offset by lower results in Alberta from lower demand due to unseasonably mild weather.

OM&A costs for the three months ended March 31, 2012 increased compared to the same periods in 2011 due to increased support costs and higher compensation costs associated with favourable results.

C O R P O R A T E : *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 March 31	
	2012	2011
Operations, maintenance, and administration	**22**	23
Depreciation and amortization	**5**	5
Operating loss	**27**	28

For the three months ended March 31, 2012, OM&A costs were comparable to the same period in 2011.

N E T I N T E R E S T E X P E N S E

The components of net interest expense are shown below:

	3 months ended March 31	
	2012	2011
Interest on debt	**56**	55
Capitalized interest	**-**	(11)
Interest expense	**56**	44
Accretion of provisions	**4**	5
Net interest expense	**60**	49

The change in net interest expense for the three months ended March 31, 2012, compared to the same period in 2011 is shown below:

	3 months ended March 31
Net interest expense, 2011	49
Lower capitalized interest	11
Higher interest rates	2
Lower debt levels	(2)
Net interest expense, 2012	**60**

INCOME TAXES

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

	3 months ended March 31	
	2012	2011
Earnings before income taxes	**111**	313
Income attributable to non-controlling interests	**(13)**	(13)
Impacts associated with certain de-designated and ineffective hedges	**(85)**	(199)
Inventory writedown	**34**	-
Gain on sale of facilities	**(3)**	-
Earnings attributable to TransAlta shareholders excluding non-comparable items subject to tax	**44**	101
Income tax expense	**2**	92
Income tax expense related to impacts associated with certain de-designated and ineffective hedges	**(30)**	(70)
Income tax recovery related to inventory writedown	**12**	-
Income tax expense related to gain on sale of facilities and development projects	**(1)**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**9**	-
Income tax expense (recovery) excluding non-comparable items	**(8)**	22
Effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items (%)	**(18)**	22

The income tax expense excluding non-comparable items for the three months ended March 31, 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 $15 million of certain outstanding tax matters during the quarter that were comparable in nature.

The effective tax rate on earnings attributable to TransAlta shareholders excluding non-comparable items for the three months ended March 31, 2012 decreased 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 during the quarter.

NON-CONTROLLING INTERESTS

Net earnings attributable to non-controlling interests for the three months ended March 31, 2012 was comparable to the same period in 2011.

FINANCIAL POSITION

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

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	(18)	Decrease in net earnings
Accounts receivable	(105)	Timing of customer receipts and lower revenues
Prepaid expenses	12	Prepayments of annual insurance premiums
Income taxes receivable	14	Resolution of certain tax matters
Property, plant, and equipment, net	(14)	Depreciation and unfavourable foreign exchange rates partially offset by additions
Accounts payable and accrued liabilities	(101)	Timing of payments and lower capital accruals
Long-term debt (including current portion)	(13)	Repayments offset by increased borrowings under credit facilities
Equity attributable to shareholders	13	Net earnings for the period offset by movements in AOCI
Non-controlling interests	(13)	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 9* of our interim condensed consolidated financial statements as at and for the three months ended March 31, 2012 for details on Financial Instruments. Refer to the Risk Management section of our 2011 Annual Report and *Note 10* 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 March 31, 2012, total Level III financial instruments had a net asset carrying value of $6 million (Dec. 31, 2011 - $7 million net liability).

During the three months ended March 31, 2012, unrealized pre-tax gains of $75 million were released from AOCI and recognized in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices which will change between now and the time the underlying hedged transactions are expected to occur. 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 period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

In addition, we discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at March 31, 2012, cumulative gains of $20 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 months ended March 31, 2012 compared to the same period in 2011:

3 months ended March 31	**2012**	2011	**Primary factors explaining change**
Cash and cash equivalents, beginning of period	**49**	35	
Provided by (used in):			
Operating activities	**183**	168	Favourable changes in working capital of $52 million offset by lower cash earnings of $37 million
Investing activities	**(165)**	(133)	Increase in additions to PP&E of $50 million offset by an increase in collateral received from counterparties of $16 million, a decrease in change in working capital related to investing activites of $9 million, and an increase in proceeds on sale of facilities of $3 million
Financing activities	**(36)**	(29)	Increase in preferred share dividends of $4 million and an increase in distributions paid to subsidiaries' non-controlling interests of $2 million, offset by a decrease in common share dividends of $2 million
Translation of foreign currency cash	**-**	(1)	
Cash and cash equivalents, end of period	**31**	40	

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, and long-term debt issued under our Canadian and U.S. shelf registrations. 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 $4.0 billion at March 31, 2012 and $4.0 billion at Dec. 31, 2011.

Credit Facilities

At March 31, 2012, we have a total of $2.0 billion (Dec. 31, 2011 - $2.0 billion) of committed credit facilities of which $0.9 billion (Dec. 31, 2011 - $0.9 billion) is not drawn and available, subject to customary borrowing conditions. At March 31, 2012, the $1.1 billion (Dec. 31, 2011 - $1.1 billion) of credit utilized under these facilities is comprised of actual drawings of $0.8 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 quarter 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 $0.9 billion available under the credit facilities, we also have $31 million of cash available.

Share Capital

On April 25, 2012, we had 227.0 million common shares outstanding and 12.0 million Series A and 11.0 million Series C first preferred shares outstanding.

At March 31, 2012, we had 224.6 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. During the three months ended March 31, 2012, 1.0 million (March 31, 2011 - 0.9 million) common shares were issued for $20 million (March 31, 2011 - $18 million). During the three months ended March 31, 2012, all the common shares were issued under the terms of the Dividend Reinvestment and Share Purchase (“DRASP”) plan. Of the 0.9 million shares issued during the three months ended March 31, 2011, 0.1 million were issued for cash proceeds of $1 million and 0.8 million were issued for $17 million under the terms of the DRASP plan.

We employ a variety of stock-based compensation to align employee and corporate objectives. At March 31, 2012, we had 1.6 million outstanding employee stock options (Dec. 31, 2011 - 1.7 million). During the three months ended March 31, 2012, 0.1 million options expired, or were exercised or cancelled (March 31, 2011 - a nominal number).

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 March 31, 2012, we provided letters of credit totalling $280 million (Dec. 31, 2011 - $328 million) and cash collateral of $51 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, carbon 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 pollution from power plants. Existing sources will have up to four years to comply. We are already proceeding with the installation of voluntary mercury capture technology at our Centralia coal-fired plant, to be operational by the end of 2012. We are also installing additional capture 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 operation in September 2011 using supercritical combustion technology to maximize thermal efficiency, as well as sulphur dioxide 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 were undertaken in 2011 and scheduled for completion in 2012, which will improve the energy and emissions efficiency of those units.

2 0 1 2 O U T L O O K

Business Environment

Power Prices

Over the balance of 2012, power prices in Alberta are expected to be lower than 2011, driven by weak prices influenced by lower natural gas prices, offset by continued load growth. In the Pacific Northwest, we continue to expect weak prices due to historically low natural gas prices and slow load growth. Market prices and the success of contracting will influence the asset values at Centralia Thermal. Continued low prices could result in an adjustment to the current $757 million carrying amount of the plant and the associated tax asset of $238 million. Because any such determination will be based on future events and circumstances no assurance can be given as to the timing or amount of any impairment, although it is possible that such an adjustment could be material and could occur in 2012.

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 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. More 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 improvement in 2011 and we expect this trend to continue through 2012 at a slow to moderate pace. We continue to monitor global events and their potential impact on the economy and our supplier and commodity counterparty relationships.

We had no counterparty losses in the first 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 three uprates at our Alberta coal PPA facilities and the completion of New Richmond. Overall production is expected to increase for 2012 due to a full year of operating Keephills Unit 3 and lower unplanned outages, offset by higher planned outages at our Alberta PPA facilities and economic dispatching at Centralia Thermal. Overall availability in 2012 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 70 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, stepping down to 65 per cent in the fourth year. As at the end of the first 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 charge recorded in the first quarter of 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 risk.

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 $65 million and $85 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 revenues.

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. To mitigate this liquidity risk, we expect to maintain $2.0 billion of committed credit facilities, and will continuously monitor our exposures and obligations.

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 21 to 26 per cent.

Capital Expenditures

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

Growth Capital Expenditures

We have four significant growth capital projects that are currently in progress with targeted completion dates between Q2 2012 and Q4 2012. A summary of each of these projects is outlined below:

	Total Project		2012		Target	
Project	Estimated spend	Spent to date[1]	Estimated spend	Spent to date[1]	completion date	Details
Keephills Unit 1 uprate	25	16	10 - 20	3	Q3 2012	An expected 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	26	23	10 - 20	13	Q2 2012	An expected 23 MW efficiency uprate at our Keephills facility
Sundance Unit 3 uprate	27	12	15 - 20	1	Q4 2012	An expected 15 MW efficiency uprate at our Sundance facility
New Richmond[2]	205	46	165 - 185	17	Q4 2012	A 68 MW wind farm in Quebec
Total growth	**283**	**97**	**200 - 245**	**34**		

Transmission

For the three months ended March 31, 2012, a total of $1 million was spent on transmission projects. The estimated spend for 2012 for transmission projects is $8 million. Transmission projects consist of the major maintenance and reconfiguration of the transmission networks of Alberta to increase capacity of power flow in the lines.

Sustaining Capital and Productivity Expenditures

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

Category	Description	Expected cost	Spent to date[3]
Routine capital	Expenditures to maintain our existing generating capacity	100 - 115	21
Productivity capital	Projects to improve power production efficiency	50 - 70	6
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	40 - 50	6
Planned maintenance	Regularly scheduled major maintenance	290 - 310	74
Total sustaining and productivity expenditures		**480 - 545**	**107**

(1) Represents amounts spent as of March 31, 2012. During the quarter, we also spent a combined $1 million on Keephills Unit 3, Ardenville, Kent Hills 2, and Bone Creek.

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

(3) Represents amounts incurred as of March 31, 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	75 - 80	290 - 310	74
Expensed	-	0 - 5	0 - 5	-
	215 - 230	75 - 85	290 - 315	74

	Coal	Gas and Renewables	Expected total	Lost to date
GWh lost	3,920 - 3,930	380 - 390	4,300 - 4,320	511

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, re-invested 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 flow, our financial position, and the amount of capital available to us under existing committed credit facilities.

FUTURE ACCOUNTING CHANGES

For a summary of future accounting changes that we have 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” in our Condensed Consolidated Statements of Earnings for the three months ended March 31, 2012 and 2011. Presenting these line items provides management and investors with a measurement of ongoing operating performance which is readily comparable from period to period.

NON-IFRS MEASURES

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

(1) Represents amounts incurred as of March 31, 2012.

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 the current period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change. In calculating comparable earnings for the first 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 the quarter. The effect of the hedge de-designation and inventory impairment will be recognized in comparable earnings over the balance of the year. We have also excluded the income tax recovery related to the resolution of certain tax matters and the gain on sale of facilities, 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.

Earnings on a Comparable Basis

Earnings on a comparable basis are reconciled to net earnings attributable to common shareholders below:

	3 months ended March 31	
	2012	2011
Net earnings attributable to common shareholders	**89**	204
Impacts associated with certain de-designated and ineffective hedges, net of tax	**(55)**	(129)
Gain on sale of facilities, net of tax	**(2)**	-
Inventory writedown, net of tax	**22**	-
Income tax recovery related to the resolution of certain tax matters	**(9)**	-
Earnings on a comparable basis	**45**	75
Weighted average number of common shares outstanding in the period	**225**	221
Earnings on a comparable basis per share	**0.20**	0.34

Comparable Gross Margin

Comparable gross margin is calculated as follows:

	3 months ended March 31	
	2012	2011
Gross margin[1]	**469**	608
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(85)**	(199)
Comparable gross margin	**384**	409

(1) This item is an Additional IFRS Measures. Refer to the Additional IFRS Measures section of this MD&A for further discussion of this item.

Comparable Operating Income

A reconciliation of comparable operating income is as follows:

	3 months ended March 31	
	2012	2011
Operating income[1]	**172**	359
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(85)**	(199)
Inventory writedown, pre-tax	**34**	-
Comparable operating income	**121**	160

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 March 31	
	2012	2011
Operating income[1]	**172**	359
Inventory writedown, pre-tax	**34**	-
Depreciation and amortization per the Consolidated Statements of Cash Flows[2]	**140**	127
Impacts associated with certain de-designated and ineffective hedges, pre-tax	**(85)**	(199)
Comparable EBITDA	**261**	287

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 March 31	
	2012	2011
Cash flow from operating activites	**183**	168
Change in non-cash operating working capital balances	**6**	58
Funds from operations	**189**	226
Weighted average number of common shares outstanding in the period	**225**	221
Funds from operations per share	**0.84**	1.02

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

(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.

Free Cash Flow

Free cash flow 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 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 March 31, 2012 represents total additions to property, plant, and equipment and intangibles per the Condensed Consolidated Statements of Cash Flows less $37 million ($36 million net of partners' contributions) that we have invested in growth projects. For the same period in 2011, we invested $34 million in growth projects.

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

	3 months ended March 31	
	2012	2011
Cash flow from operating activities	**183**	168
Add (deduct):		
Changes in non-cash operating working capital	**6**	58
Sustaining capital and productivity expenditures	**(107)**	(58)
Dividends paid on common shares	**(45)**	(47)
Dividends paid on preferred shares	**(8)**	(4)
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(17)
Free cash flow	**10**	100

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

SELECTED QUARTERLY INFORMATION

	Q2 2011	Q3 2011	Q4 2011	**Q1 2012**
Revenue	515	629	701	**656**
Net earnings attributable to common shareholders	12	50	24	**89**
Net earnings per share attributable to common shareholders, basic and diluted	0.05	0.22	0.11	**0.40**
Comparable earnings per share	0.29	0.27	0.13	**0.20**

	Q2 2010	Q3 2010	Q4 2010	Q1 2011
Revenue	547	651	779	818
Net earnings attributable to common shareholders	63	40	92	204
Net earnings per share attributable to common shareholders, basic and diluted	0.29	0.18	0.42	0.92
Comparable earnings per share	0.15	0.18	0.36	0.34

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 are 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 was 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 March 31, 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 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 risk 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

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2012**	2011
Revenues *(Note 4)*	**656**	818
Fuel and purchased power *(Note 5)*	**187**	210
Gross margin	**469**	608
Operations, maintenance, and administration *(Note 5)*	**127**	128
Depreciation and amortization	**129**	114
Inventory writedown *(Note 11)*	**34**	-
Taxes, other than income taxes	**7**	7
Operating income	**172**	359
Finance lease income	**2**	2
Gain on sale of facilities *(Note 3)*	**3**	-
Foreign exchange gain (loss)	**(6)**	1
Net interest expense *(Notes 7 and 10)*	**(60)**	(49)
Earnings before income taxes	**111**	313
Income tax expense *(Note 8)*	**2**	92
Net earnings	**109**	221
Net earnings attributable to:		
TransAlta shareholders	**96**	208
Non-controlling interests	**13**	13
	109	221
Net earnings attributable to TransAlta shareholders	**96**	208
Preferred share dividends *(Note 20)*	**7**	4
Net earnings attributable to common shareholders	**89**	204
Weighted average number of common shares outstanding in the period *(millions)*	**225**	221
Net earnings per share attributable to common shareholders, basic and diluted	**0.40**	0.92

See accompanying notes.

TRANSALTA CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions of Canadian dollars)

Unaudited	3 months ended March 31 **2012**	2011
Net earnings	**109**	221
Other comprehensive income (loss)		
Losses on translating net assets of foreign operations	**(32)**	(49)
Gains on financial instruments designated as hedges of foreign operations, net of tax(1)	**21**	33
Losses on derivatives designated as cash flow hedges, net of tax(2)	**(9)**	(58)
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)	**(9)**	(132)
Net actuarial gains (losses) on defined benefit plans, net of tax(5)	**(10)**	1
Other comprehensive loss	**(38)**	(205)
Comprehensive income	**71**	16
Total comprehensive income (loss) attributable to:		
Common shareholders	**65**	(1)
Non-controlling interests	**6**	17
	71	16

(1) Net of income tax expense of 3 for the three months ended March 31, 2012 (2011 - 4 expense).
(2) Net of income tax expense of 1 for the three months ended March 31, 2012 (2011 - 13 recovery).
(3) Net of income taxes of nil for the three months ended March 31, 2012 (2011 - nil).
(4) Net of income tax expense of 17 for the three months ended March 31, 2012 (2011 - 77 expense).
(5) Net of income tax recovery of 3 for the three months ended March 31, 2012 (2011 - 1 expense).

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in millions of Canadian dollars)

Unaudited	**March 31, 2012**	Dec. 31, 2011
Cash and cash equivalents	**31**	49
Accounts receivable	**436**	541
Current portion of finance lease receivable	**3**	3
Collateral paid *(Note 10)*	**51**	45
Prepaid expenses	**20**	8
Risk management assets *(Notes 9 and 10)*	**363**	391
Inventory *(Note 11)*	**86**	85
Income taxes receivable *(Note 12)*	**16**	2
	1,006	1,124
Investments *(Note 6)*	**187**	193
Long-term receivable *(Note 13)*	**18**	18
Finance lease receivable	**41**	42
Property, plant, and equipment *(Note 14)*		
Cost	**11,451**	11,386
Accumulated depreciation	**(4,194)**	(4,115)
	7,257	7,271
Goodwill	**447**	447
Intangible assets	**275**	276
Deferred income tax assets	**182**	176
Risk management assets *(Notes 9 and 10)*	**121**	99
Other assets *(Note 15)*	**89**	90
Total assets	**9,623**	9,736
Short-term debt	**3**	-
Accounts payable and accrued liabilities	**362**	463
Decommissioning and other provisions *(Note 16)*	**111**	99
Collateral received *(Note 10)*	**16**	16
Risk management liabilities *(Notes 9 and 10)*	**192**	208
Income taxes payable	**19**	22
Dividends payable *(Notes 19 and 20)*	**66**	67
Current portion of long-term debt *(Notes 10 and 17)*	**310**	316
	1,079	1,191
Long-term debt *(Notes 10 and 17)*	**3,714**	3,721
Decommissioning and other provisions *(Note 16)*	**277**	283
Deferred income tax liabilities	**489**	491
Risk management liabilities *(Notes 9 and 10)*	**153**	142
Deferred credits and other long-term liabilities *(Note 18)*	**284**	281
Equity		
Common shares *(Note 19)*	**2,293**	2,273
Preferred shares *(Note 20)*	**562**	562
Contributed surplus	**9**	9
Retained earnings	**551**	527
Accumulated other comprehensive loss *(Note 21)*	**(133)**	(102)
Equity attributable to shareholders	**3,282**	3,269
Non-controlling interests	**345**	358
Total equity	**3,627**	3,627
Total liabilities and equity	**9,623**	9,736

Contingencies *(Note 22)*

Subsequent events *(Note 26)*

See accompanying notes.

TRANSALTA CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in millions of Canadian dollars)

3 months ended March 31, 2012

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, 2011	2,273	562	9	527	(102)	3,269	358	**3,627**
Net earnings	-	-	-	96	-	96	13	**109**
Other comprehensive income (loss):								
Losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(11)	(11)	-	**(11)**
Net losses on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(10)	(10)	(7)	**(17)**
Net actuarial losses on defined benefits plans, net of tax	-	-	-	-	(10)	(10)	-	**(10)**
Total comprehensive income (loss)						65	6	**71**
Common share dividends	-	-	-	(65)	-	(65)	-	**(65)**
Preferred share dividends	-	-	-	(7)	-	(7)	-	**(7)**
Distributions to non-controlling interests	-	-	-	-	-	-	(19)	**(19)**
Common shares issued	20	-	-	-	-	20	-	**20**
Balance, March 31, 2012	**2,293**	**562**	**9**	**551**	**(133)**	**3,282**	**345**	**3,627**

3 months ended March. 31, 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	-	-	-	208	-	208	13	221
Other comprehensive income (loss):								
Losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(16)	(16)	-	(16)
Net gains (losses) on derivatives designated as cash flow hedges, net of tax	-	-	-	-	(194)	(194)	4	(190)
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	1	1	-	1
Total comprehensive income (loss)						(1)	17	16
Preferred share dividends	-	-	-	(4)	-	(4)	-	(4)
Distributions to non-controlling interests	-	-	-	-	-	-	(17)	(17)
Common shares issued	18	-	-	-	-	18	-	18
Effect of share-based payment plans	-	-	1	-	-	1	-	1
Balance, March 31, 2011	2,222	293	8	635	(24)	3,134	431	3,565

(1) Refer to Note 21 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 March 31	
Unaudited	**2012**	2011
Operating activities		
Net earnings	**109**	221
Depreciation and amortization *(Note 24)*	**140**	127
Gain on sale of facilities *(Note 3)*	**(3)**	-
Accretion of provisions *(Note 16)*	**4**	5
Decommissioning and restoration costs settled *(Note 16)*	**(6)**	(6)
Deferred income tax expense *(Note 8)*	**3**	89
Unrealized gain from risk management activities *(Note 10)*	**(69)**	(202)
Unrealized foreign exchange loss	**9**	-
Other non-cash items	**2**	(8)
Cash flow from operations before changes in working capital	**189**	226
Change in non-cash operating working capital balances *(Note 25)*	**(6)**	(58)
Cash flow from operating activities	**183**	168
Investing activities		
Additions to property, plant, and equipment *(Note 14)*	**(137)**	(87)
Additions to intangibles	**(6)**	(5)
Proceeds on sale of property, plant, and equipment	**-**	1
Proceeds on sale of facilities	**3**	-
Resolution of outstanding tax matters	**-**	2
Realized gains (losses) on financial instruments	**(2)**	2
Net decrease in collateral received from counterparties	**-**	(16)
Net increase in collateral paid to counterparties	**(6)**	(9)
Other	**(5)**	-
Change in non-cash working capital	**(12)**	(21)
Cash flow used in investing activities	**(165)**	(133)
Financing activities		
Net increase in borrowings under credit facilities *(Note 17)*	**40**	40
Repayment of long-term debt *(Note 17)*	**(2)**	(2)
Dividends paid on common shares *(Note 19)*	**(45)**	(47)
Dividends paid on preferred shares *(Note 20)*	**(8)**	(4)
Net proceeds on issuance of common shares *(Note 19)*	**-**	1
Distributions paid to subsidiaries' non-controlling interests	**(19)**	(17)
Decrease in finance lease receivable	**1**	1
Other	**(3)**	(1)
Cash flow used in financing activities	**(36)**	(29)
Cash flow from operating, investing, and financing activities	**(18)**	6
Effective change in value of foreign cash	**-**	(1)
Increase (decrease) in cash and cash equivalents	**(18)**	5
Cash and cash equivalents, beginning of period	**49**	35
Cash and cash equivalents, end of period	**31**	40
Cash income taxes paid (recovered)	**15**	(6)
Cash interest paid	**46**	33

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 April 25, 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

New or amended accounting standards that have been issued by the International Accounting Standards Board 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. DISPOSALS

During the three months ended March 31, 2012, the Corporation realized an pre-tax gain of $3 million 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.

4. REVENUES

Several of the Corporation's Power Purchase Agreements 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 for the three months ended March 31, 2012, was $42 million (March 31, 2011 - $49 million).

5. EXPENSES BY NATURE

Expenses classified by nature are as follows:

	3 months ended March 31, 2012		3 months ended March 31, 2011	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**139**	**-**	152	-
Purchased power	**37**	**-**	48	-
Salaries and benefits	**1**	**65**	1	70
Depreciation	**10**	**-**	9	-
Other operating expenses	**-**	**62**	-	58
Total	**187**	**127**	210	128

6. INVESTMENTS

The Corporation's investments in jointly controlled entities accounted for using the equity method consists of its investments in CE Gen and Wailuku.

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 March 31	
	2012	2011
Results of operations		
Revenues	**26**	28
Expenses	**(26)**	(28)
Proportionate share of net income	**-**	-

As at	**March 31, 2012**	Dec. 31, 2011
Financial position		
Current assets	**49**	42
Long-term assets	**413**	423
Current liabilities	**(37)**	(29)
Long-term liabilities	**(224)**	(229)
Non-controlling interests	**(14)**	(14)
Proportionate share of net assets	**187**	193

7. NET INTEREST EXPENSE

The components of net interest expense are as follows:

	3 months ended March 31	
	2012	2011
Interest on debt	**56**	55
Capitalized interest *(Note 14)*	**-**	(11)
Interest expense	**56**	44
Accretion of provisions *(Note 16)*	**4**	5
Net interest expense	**60**	49

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

8. INCOME TAXES

The components of income tax expense are as follows:

	3 months ended March 31	
	2012	2011
Current tax expense	**13**	3
Benefit arising from the resolution of outstanding tax matters	**(24)**	-
Deferred tax expense related to the origination and reversal of temporary differences	**13**	89
Income tax expense	**2**	92

Presented in the Condensed Consolidated Statements of Earnings as follows:

	3 months ended March 31	
	2012	2011
Current tax expense (recovery)	**(1)**	3
Deferred tax expense	**3**	89
Income tax expense	**2**	92

9. 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 three months ended March 31, 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	-	16	3	-	37	11	-	53	14
New contracts	-	-	-	-	4	-	-	4	-
Contracts settled	-	7	4	-	(67)	(5)	-	(60)	(1)
Discontinued hedge accounting on certain contracts	-	(26)	-	-	26	-	-	-	-
Net risk management assets (liabilities) at March 31, 2012	**-**	**(93)**	**(7)**	**-**	**287**	**13**	**-**	**194**	**6**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			7			-			7
Realized gain (loss) included in earnings before income taxes			(4)			5			1
Unrealized gain included in earnings before income taxes relating to net assets held at March 31, 2012						11			11

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 March 31, 2012 is estimated to be +/- $32 million (Dec. 31, 2011 - +/- $33 million).

Other Risk Management Assets and Liabilities

Other risk management assets and liabilities include risk management assets and liabilities that are used in hedging non-energy trading transactions, such as debt, and the net investment in foreign operations.

The following table summarizes the key factors impacting the fair value of other risk management assets and liabilities by classification level during the three months ended March 31, 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	-	(12)	-	-	-	-	-	(12)	-
New contracts	-	-	-	-	(2)	-	-	(2)	-
Contracts settled	-	3	-	-	-	-	-	3	-
Net risk management liabilities at March 31, 2012	**-**	**(59)**	**-**	**-**	**(2)**	**-**	**-**	**(61)**	**-**

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

	Fair value				Total carrying
As at March 31, 2012	**Level I**	**Level II**	**Level III**	**Total**	**value**
Long-term debt - March 31, 2012(1)	**-**	**4,270**	**-**	**4,270**	**4,024**
Long-term debt - Dec. 31, 2011(1)	-	4,324	-	4,324	4,037

(1) Includes current portion.

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

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 March 31, 2012, the unamortized gain is $4 million (Dec. 31, 2011 - $4 million gain).

10. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	March 31, 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	-	3	-	357	360	390
Long-term	-	-	-	96	96	73
Total energy trading risk management assets	-	3	-	453	456	463
Other						
Current	3	-	-	-	3	1
Long-term	-	1	24	-	25	26
Total other risk management assets	3	1	24	-	28	27
Risk management liabilities						
Energy trading						
Current	-	16	-	134	150	167
Long-term	-	87	-	19	106	106
Total energy trading risk management liabilities	-	103	-	153	256	273
Other						
Current	4	36	-	2	42	41
Long-term	-	47	-	-	47	36
Total other risk management liabilities	4	83	-	2	89	77
Net energy trading risk management assets (liabilities)	**-**	**(100)**	**-**	**300**	**200**	190
Net other risk management assets (liabilities)	**(1)**	**(82)**	**24**	**(2)**	**(61)**	(50)
Net total risk management assets (liabilities)	**(1)**	**(182)**	**24**	**298**	**139**	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, as follows:

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (Dec. 31, 2011 - U.S.$820 million) and borrowings under a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2011 - U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in foreign operations.

As at	**March 31, 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 Currency Forward Contracts							
AUD190	**CAD191**	**(4)**	**2012**	AUD185	CAD184	(4)	2012
USD165	**CAD167**	**3**	**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 March 31, 2012, are as follows:

As at	**March 31, 2012**		Dec. 31, 2011	
Type (Thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**4,456**	**3**	7,817	4
Natural gas (GJ)	**1,451**	**38,921**	2,032	39,022
Oil (gallons)	**-**	**-**	-	6,300

During the three months ended March 31, 2012, unrealized pre-tax gains of $75 million (March 31, 2011 - $204 million gain) 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 underlying hedged transactions are expected to occur. 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 period, future reported earnings will be lower, however, the expected cash flows from these contracts will not change.

During the three months ended March 31, 2012, the Corporation discontinued hedge accounting for certain cash flow hedges that no longer met the criteria for hedge accounting. As at March 31, 2012, cumulative gains of $20 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	**March 31, 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 Exchange Forward Contracts - receipts/expenditures							
CAD256	**USD239**	**(10)**	**2012-2017**	CAD250	USD233	(8)	2012-2017
USD8	**CAD8**	**-**	**2012**	USD8	CAD8	-	2012
CAD90	**EUR65**	**(3)**	**2012**	CAD103	EUR74	(6)	2012
Foreign Exchange Forward Contracts - foreign denominated debt							
CAD312	**USD300**	**(12)**	**2012**	CAD312	USD300	(5)	2012
CAD314	**USD300**	**(10)**	**2013**	CAD314	USD300	(5)	2013
Cross-Currency Swaps - foreign denominated debt							
CAD530	**USD500**	**(27)**	**2015**	CAD530	USD500	(22)	2015

iii. Interest Rate Risk Management

The Corporation has outstanding forward start interest rate swaps with fixed rates ranging from 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	**March 31, 2012**		Dec. 31, 2011		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
USD300	**(20)**	**2012**	USD300	(25)	2012

iv. Cash Flow Hedge Impacts

The following tables summarize the impacts of cash flow hedges:

3 months ended March 31, 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) recognized in earnings**
Commodity contracts	**5**	Revenue	**16**	Revenue	**(75)**
Foreign exchange forwards on project hedges	**(2)**	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	**(5)**	Foreign exchange (gain) loss	**33**	Foreign exchange (gain) loss	**-**
Forward start interest rate swaps	**5**	Interest expense	**-**	Interest expense	**-**
OCI impact	**(8)**	**OCI impact**	**50**	**Net earnings impact**	**(75)**

3 months ended March 31, 2011

Derivatives in cash flow hedging relationships	Effective portion Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Ineffective portion Location of (gain) loss reclassified from OCI	Pre-tax (gain) recognized in earnings
Commodity contracts	(36)	Revenue	(38)	Revenue	(204)
Foreign exchange forwards on project hedges	(3)	Property, plant, and equipment	-	Property, plant, and equipment	-
Foreign exchange forwards on U.S. debt hedges	(18)	Foreign exchange (gain) loss	33	Foreign exchange (gain) loss	-
Cross-currency swaps	(14)	Foreign exchange (gain) loss	-	Foreign exchange (gain) loss	-
OCI impact	(71)	OCI impact	(5)	Net earnings impact	(204)

Over the next 12 months, the Corporation estimates that $7 million of after-tax losses will be reclassified from AOCI to net earnings. These estimates assume constant 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	**March 31, 2012**		Dec. 31, 2011		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD150	**24**	**2018**	USD150	25	2018

Including the interest rate swaps above, 24 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2011 - 23 per cent).

ii. Fair Value Hedge Impacts

The net impact of the ineffective portion of fair value hedges recognized in net interest expense in the Condensed Consolidated Statements of Earnings for the three months ended March 31, 2012 was nil (March 31, 2011 - nil).

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	March 31, 2012		Dec. 31, 2011	
Type (Thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**70,292**	**59,617**	56,374	47,133
Natural gas (GJ)	**1,134,984**	**1,115,906**	1,007,959	1,030,710
Transmission (MWh)	**-**	**2,867**	-	2,908
Oil (gallons)	**-**	**9,576**	-	6,552

b. Other Non-hedge Derivatives

As at	March 31, 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 Exchange Forward Contracts							
CAD41	**AUD39**	**(1)**	**2012**	CAD37	AUD36	-	2012
CAD19	**USD18**	**(1)**	**2012**	CAD19	USD19	-	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 months ended March 31, 2012, the Corporation recognized a net unrealized gain of $4 million (March 31, 2011 - gain of $5 million) related to commodity derivatives.

For the three months ended March 31, 2012, a gain of nil (March 31, 2011 - $4 million loss) related to foreign exchange derivatives was recognized and comprised of a net unrealized loss of $1 million (March 31, 2011 - $3 million gain) and a net realized gain of $1 million (March 31, 2011 - $7 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 March 31, 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 March 31, 2012 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $5 million (Dec. 31, 2011 - $5 million). VaR at March 31, 2012 associated with positions and economic hedges that do not meet hedge accounting requirements was $7 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 Other Comprehensive Income ("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 increase or decrease is a reasonable potential change in market interest rates over the next quarter.

	3 months ended March 31			
	2012		2011	
	Net earnings increase[(1)]	**OCI loss[(1)]**	Net earnings increase[(1)]	OCI loss[(1)]
50 basis point change	**1**	**(5)**	1	-

(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 a six cent (March 31, 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.

	3 months ended March 31			
	2012		2011	
Currency	**Net earnings decrease(1)**	**OCI gain(1), (2)**	Net earnings decrease(1)	OCI gain(1), (2)
USD	**(1)**	**11**	(1)	9
AUD	**(1)**	**-**	(1)	-
EUR	**-**	**3**	-	-
Total	**(2)**	**14**	(2)	9

(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 March 31, 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 March 31, 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 March 31, 2012 was $47 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 financial assets as at March 31, 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	362	-	-	-	-	-	362
Collateral received	16	-	-	-	-	-	16
Short-term debt	3	-	-	-	-	-	3
Debt[1]	307	610	209	1,193	29	1,662	4,010
Energy trading risk management (assets) liabilities	(190)	(39)	(18)	12	10	25	(200)
Other risk management (assets) liabilities	39	13	2	29	2	(24)	61
Interest on long-term debt	150	189	163	124	110	825	1,561
Dividends payable	66	-	-	-	-	-	66
Total	**753**	**773**	**356**	**1,358**	**151**	**2,488**	**5,879**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2016.

C. Collateral

I. Financial Assets Provided as Collateral

At March 31, 2012, the Corporation provided $51 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 March 31, 2012, the Corporation received $16 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 March 31, 2012, the Corporation had posted collateral of $35 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 $89 million of collateral to its counterparties based upon the value of the derivatives at March 31, 2012.

11. 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	March 31, 2012	Dec. 31, 2011
Coal	**82**	78
Natural gas	**4**	5
Purchased emission credits	**-**	2
Total	**86**	85

For the three months ended March 31, 2012, coal inventory at the Corporation's Centralia plant was written down by $34 million to its net realizable value.

12. 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.

13. LONG-TERM RECEIVABLE

In 2011, TransAlta had net collateral of approximately $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 an $18 million reserve in 2011 against the collateral that had been posted with MF Global Inc.

14. 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)	-	-	-	132	6	137
Depreciation	-	(68)	(23)	(22)	(10)	-	(3)	(126)
Revisions and additions to decommissioning and restoration costs	-	-	-	(1)	-	-	-	(1)
Retirement of assets	-	(5)	-	-	-	-	-	(5)
Change in foreign exchange rates	-	(15)	-	-	-	-	(1)	(16)
Transfers	-	96	-	18	6	(131)	8	(3)
As at March 31, 2012	74	3,160	1,018	2,052	530	197	226	7,257

During the three months ended March 31, 2012, the Corporation capitalized a nominal amount (March 31, 2011 - $11 million) of interest to PP&E at a weighted average rate of 5.38 per cent (March 31, 2011 - 5.11 per cent).

15. OTHER ASSETS

The components of other assets are as follows:

As at	March 31, 2012	Dec. 31, 2011
Deferred license fees	**22**	22
Project development costs	**34**	33
Deferred service costs	**18**	18
Keephills 3 transmission deposit	**7**	8
Other	**8**	9
Total other assets	**89**	90

16. 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	10	11
Liabilities settled in period	(6)	-	(6)
Accretion	4	-	4
Revisions in estimated cash flows	1	2	3
Revisions in discount rates	(2)	-	(2)
Reversals	-	(2)	(2)
Change in foreign exchange rates	(2)	-	(2)
	297	91	388
Less: current portion	**26**	**85**	**111**
Balance, March 31, 2012	**271**	**6**	**277**

17. LONG-TERM DEBT

The amounts outstanding are as follows:

As at	March 31, 2012			Dec. 31, 2011		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**836**	**836**	**2.1%**	806	806	2.1%
Debentures	**835**	**851**	**6.6%**	833	851	6.6%
Senior notes[3]	**1,937**	**1,900**	**6.0%**	1,979	1,940	6.0%
Non-recourse[4]	**374**	**381**	**5.9%**	375	382	5.9%
Other	**42**	**42**	**6.6%**	44	44	6.6%
	4,024	**4,010**		4,037	4,023	
Less: recourse current portion	**(308)**	**(308)**		(314)	(314)	
Less: non-recourse current portion	**(2)**	**(2)**		(2)	(2)	
Total long-term debt	**3,714**	**3,700**		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 March 31, 2012 (U.S.$306 million - Dec. 31, 2011).

(3) U.S. face value at March 31, 2012 - U.S.$1,900 million, Dec. 31, 2011 - U.S.$1,900 million.

(4) Includes U.S.$20 million at March 31, 2012 (Dec. 31, 2011 - U.S.$20 million).

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

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.

18. DEFERRED CREDITS AND OTHER LONG-TERM LIABILITIES

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

As at	March 31, 2012	Dec. 31, 2011
Deferred coal revenues	**52**	52
Present value of defined employee benefits obligation	**202**	190
Long-term incentive accruals	**10**	18
Other	**20**	21
Total deferred credits and other long-term liabilities	**284**	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.

19. COMMON SHARES

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. At March 31, 2012, the Corporation had 224.6 million (Dec. 31, 2011 - 223.6 million) common shares issued and outstanding. During the three months ended March 31, 2012, 1.0 million (March 31, 2011 - 0.8 million) common shares were issued under the Dividend Reinvestment and Share Purchase ("DRASP") plan for $20 million (March 31, 2011 - $17 million), and nil (March 31, 2011 - 0.1 million) common shares were issued for cash proceeds of nil (March 31, 2011 - $1 million).

B. Stock Options

At March 31, 2012 the Corporation had 1.6 million outstanding employee stock options (Dec. 31, 2011 - 1.7 million). During the three months ended March 31, 2012, 0.1 million options expired, or were exercised or cancelled (March 31, 2011 - a nominal number).

For the three months ended March 31, 2012, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was a nominal amount (March 31, 2011 - $1 million).

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

During the three months ended March 31, 2012, the Corporation issued 1.0 million (March 31, 2011 - 0.8 million) common shares under the provision of the DRASP plan for $20 million (March 31, 2011 - $17 million). During February 2012, the Corporation amended the DRASP plan, which is now called the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan ("the Plan"), and is more fully discussed in Note 24(C) of the most recent annual consolidated financial statements. Under the Plan, 66 per cent of shareholders elected to participate in the dividend reinvestment for the dividend that was payable on April 1, 2012.

D. Dividends

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

Date declared	Payment date	Dividend per share *($)*	Dividends payable as at March 31, 2012	Total dividends	Dividends paid in cash	Dividends paid in shares under the Plan
Jan. 25, 2012	Apr. 1, 2012	0.29	66	65	22	43
Total		**0.29**	**66**	**65**		

Date declared	Payment date	Dividend per share *($)*	Dividends payable as at Dec. 31, 2011	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	66	65	45	20
Total		**0.87**	**66**	**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.

20. 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 March 31, 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 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 *($)*	Dividends payable as at March 31, 2012	Total dividends
Jan. 25, 2012	March 31, 2012	0.2875	-	3

Date declared	Payment date	Dividend per share *($)*	Dividends payable as at Dec. 31, 2011	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 [1] *($)*	Dividends payable as at March 31, 2012	Total dividends
Jan. 25, 2012	March 31, 2012	0.3844	-	4

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

21. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	2012	2011
Currency translation adjustment		
Opening balance	**(28)**	(27)
Losses on translating net assets of foreign operations	**(32)**	(49)
Gains on financial instruments designated as hedges of foreign operations (1)	**21**	33
Balance, March 31	**(39)**	(43)
Cash flow hedges		
Opening balance	**(28)**	232
Losses on derivatives designated as cash flow hedges, net of tax (2)	**(2)**	(62)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax (3)	**(9)**	(132)
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax (4)	**1**	-
Balance, March 31	**(38)**	38
Employee future benefits		
Opening balance	**(46)**	(20)
Net actuarial losses (gains) on defined benefit plans, net of tax (5)	**(10)**	1
Balance, March 31	**(56)**	(19)
Accumulated other comprehensive loss	**(133)**	(24)

(1) Net of income tax expense of 3 for the three months ended March 31, 2012 (2011 - 4 expense).

(2) Net of income tax expense of 1 for the three months ended March 31, 2012 (2011 - 13 recovery).

(3) Net of income taxes of nil for the three months ended March 31, 2012 (2011 - nil).

(4) Net of income tax expense of 17 for the three months ended March 31, 2012 (2011 - 77 expense).

(5) Net of income tax recovery of 3 for the three months ended March 31, 2012 (2011 - 1 expense).

22. 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.

23. 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 March 31, 2011 was $280 million (Dec. 31, 2011 - $328 million) with no (Dec. 31, 2011 - nil) amounts exercised by third parties under these arrangements.

24. SEGMENT DISCLOSURES

A. Reported Segment Earnings

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

3 months ended March 31, 2012	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**639**	**17**	**-**	**656**
Fuel and purchased power	**187**	**-**	**-**	**187**
Gross margin	**452**	**17**	**-**	**469**
Operations, maintenance and administration	**98**	**7**	**22**	**127**
Depreciation and amortization	**124**	**-**	**5**	**129**
Inventory writedown	**34**	**-**	**-**	**34**
Taxes, other than income taxes	**7**	**-**	**-**	**7**
Intersegment cost allocation	**3**	**(3)**	**-**	**-**
Operating income	**186**	**13**	**(27)**	**172**
Finance lease income	**2**	**-**	**-**	**2**
Gain on sale of facilities				**3**
Foreign exchange loss				**(6)**
Net interest expense				**(60)**
Earnings before income taxes				**111**

3 months ended March 31, 2011	Generation	Energy Trading	Corporate	Total
Revenues	803	15	-	818
Fuel and purchased power	210	-	-	210
Gross margin	593	15	-	608
Operations, maintenance and administration	100	5	23	128
Depreciation and amortization	109	-	5	114
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation	2	(2)	-	-
Operating income	375	12	(28)	359
Finance lease income	2	-	-	2
Foreign exchange gain				1
Net interest expense				(49)
Earnings before income taxes				313

Included in the Generation Segment results for the three months ended March 31, 2012 is $7 million (March 31, 2011 - $6 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**
March 31, 2012	**8,931**	**343**	**349**	**9,623**
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 March 31	
	2012	2011
Depreciation and amortization expense on the Condensed Consolidated Statement of Earnings	**129**	114
Depreciation included in fuel and purchased power	**10**	9
Other	**1**	4
Depreciation and amortization expense on the Condensed Consolidated Statements of Cash Flows	**140**	127

25. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended March 31	
	2012	2011
Source (use) of cash:		
Accounts receivable	**104**	109
Prepaid expenses	**(15)**	(13)
Income taxes receivable	**(14)**	6
Inventory	**(2)**	(33)
Accounts payable and accrued liabilities	**(90)**	(133)
Decommissioning and other provisions	**12**	6
Income taxes payable	**(1)**	-
Change in non-cash operating working capital	**(6)**	(58)

26. SUBSEQUENT EVENTS

On April 26, 2012, Project Pioneer's industry partners announced they will 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 market for carbon sales and the price of emissions reductions were insufficient to allow the project to proceed.

SUPPLEMENTAL INFORMATION

		March 31, 2012	Dec. 31, 2011
Closing market price (TSX) ($)		**18.70**	21.02
Price range for the last 12 months (TSX) ($)	High	**21.37**	23.24
	Low	**18.52**	19.45
Debt to invested capital (%)		**52.4**	52.4
Debt to invested capital excluding non-recourse debt (%)		**50.0**	49.9
Return on equity attributable to common shareholders (%)		**6.1**	10.6
Comparable return on equity attributable to common shareholders[(1), (2)] (%)		**7.0**	8.4
Return on capital employed[(1)] (%)		**6.2**	8.8
Comparable return on capital employed[(1), (2)] (%)		**6.8**	7.5
Cash dividends per share[(1)] ($)		**1.16**	1.16
Price/comparable earnings ratio[(1)] (times)		**20.8**	20.4
Earnings coverage[(1)] (times)		**1.8**	2.7
Dividend payout ratio based on net earnings[(1)] (%)		**148.0**	66.9
Dividend payout ratio based on comparable earnings[(1), (2)] (%)		**129.5**	84.3
Dividend payout ratio based on funds from operations[(1), (2)] (%)		**33.5**	24.0
Dividend yield[(1)] (%)		**6.2**	5.5
Cash flow to debt[(1)] (%)		**19.3**	20.2
Cash flow to interest coverage[(1)] (times)		**4.3**	4.4

(1) Last 12 months

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

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 common shareholders - cash and cash equivalents)

Return on common shareholders' equity = 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 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 depts. 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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