TransAlta™

TRANSALTA CORPORATION
SECOND QUARTER REPORT FOR 2010

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 consolidated financial statements of TransAlta Corporation as at and for the three and six months ended June 30, 2010 and 2009, and should also be read in conjunction with the audited consolidated financial statements and MD&A contained within our 2009 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 Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). All tabular amounts in the following discussion are in millions of Canadian dollars unless otherwise noted. This MD&A is dated July 28, 2010. 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 two business segments: Generation and Energy Trading[(1)]. Our 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.

In this MD&A, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant income statement and balance sheet items. While individual balance sheet line items will be impacted by foreign exchange fluctuations, the net impact of the translation of individual items relating to self-sustaining foreign operations is reflected in the equity section of the Consolidated Balance Sheets.

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(1) Our Energy Trading segment was referred to as "Commercial Operations and Development" in 2009.

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

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Availability (%)	**81.9**	82.8	**86.7**	84.6
Production (GWh)	**10,201**	9,656	**23,115**	21,829
Revenue	**582**	585	**1,308**	1,341
Gross margin[1]	**353**	346	**757**	727
Operating income[1]	**55**	14	**189**	99
Net earnings (loss)	**51**	(6)	**118**	36
Net earnings (loss) per share, basic and diluted	**0.23**	(0.03)	**0.54**	0.18
Comparable earnings (loss) per share[1]	**0.10**	(0.03)	**0.40**	0.16
EBITDA[1]	**182**	142	**431**	354
Funds from operations[1]	**184**	94	**374**	285
Cash flow from operating activities	**98**	57	**272**	140
Cash flow from operating activities per share[1]	**0.45**	0.29	**1.24**	0.71
Free cash flow (deficiency)[1]	**(92)**	(144)	**(36)**	(208)
Cash dividends declared per share	**0.29**	0.29	**0.58**	0.58

	As at June 30, 2010	As at Dec. 31, 2009
Total assets	**9,964**	9,775
Total long-term financial liabilities	**5,554**	5,537

AVAILABILITY & PRODUCTION

Availability for the three months ended June 30, 2010 decreased compared to the same period in 2009 primarily due to higher planned and unplanned outages at Centralia Thermal, and the outage at Unit 3 of our Sundance facility, partially offset by lower planned outages at the Keephills plant.

Availability for the six months ended June 30, 2010 increased compared to the same period in 2009 primarily due to lower planned outages at the Keephills plant, partially offset by higher planned and unplanned outages at Centralia Thermal.

Production for the three and six months ended June 30, 2010 increased 545 gigawatt hours ("GWh") and 1,286 GWh, respectively, compared to the same period in 2009 primarily due to lower economic dispatching at Centralia Thermal, lower planned outages at the Keephills plant, and higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro"), partially offset by the decommissioning of Wabamun, higher planned and unplanned outages at Centralia Thermal, higher unplanned outages at the Sundance plant, and the expiration of the long-term contract at Saranac.

(1) Gross margin, operating income, comparable earnings (loss) per share, earnings before interest, taxes, depreciation, and amortization ("EBITDA"), funds from operations, cash flow from operating activities per share, and free cash flow (deficiency) are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings (loss) and cash flow from operating activities.

NET EARNINGS (LOSS)

The primary factors contributing to the change in net earnings for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30	6 months ended June 30
Net (loss) earnings, 2009	(6)	36
Increase in Generation gross margins	22	46
Decrease in Energy Trading gross margins	(15)	(16)
Decrease in operations, maintenance, and administration costs	35	49
Decrease in depreciation expense	-	13
Increase in net interest expense	-	(15)
Decrease in non-controlling interests	3	12
Increase in income tax recovery	16	3
Other	(4)	(10)
Net earnings, 2010	**51**	**118**

Generation gross margins increased for the three months ended June 30, 2010 compared to the same period in 2009 due to favourable pricing, higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, lower planned outages at the Keephills plant, and the new agreement with the Ontario Power Authority ("OPA") at our Sarnia regional cogeneration power plant that came into effect in the third quarter of 2009, partially offset by the expiration of the long-term contract at Saranac, the outage at Unit 3 of our Sundance facility, and unfavourable foreign exchange rates.

For the six months ended June 30, 2010, Generation gross margins increased due to lower planned outages at the Keephills plant, higher wind and hydro volumes as a result of the acquisition of Canadian Hydro, and the new agreement with the OPA at our Sarnia regional cogeneration power plant, partially offset by the expiration of the long-term contract at Saranac and unfavourable foreign exchange rates.

Energy Trading gross margins decreased for the three and six months ended June 30, 2010 relative to the same period in 2009 primarily due to reduced margins in the eastern region resulting from lower margins captured on regional spread strategies and power congestion constraints.

Operations, maintenance, and administration ("OM&A") costs for the three and six months ended June 30, 2010 decreased compared to the same period in 2009 due to lower planned outages and favourable foreign exchange rates, partially offset by the acquisition of Canadian Hydro.

Depreciation expense for the three months ended June 30, 2010 was comparable to the same period in 2009 as a result of an increased asset base primarily due to the acquisition of Canadian Hydro being offset by lower production at Saranac, which was depreciated on a unit of production basis, favourable foreign exchange rates, and a change in estimated useful lives of certain coal generating facilities and mining assets.

For the six months ended June 30, 2010, depreciation expense decreased due to a reduction in the estimate of the costs associated with decommissioning our Wabamun plant, lower production at Saranac, which was depreciated on a unit of production basis, favourable foreign exchange rates, and a change in estimated useful lives of certain coal generating facilities and mining assets, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

Net interest expense for the three months ended June 30, 2010 was comparable to the same period in 2010 as a result of higher debt levels being offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

For the six months ended June 30, 2010, net interest expense increased compared to the same period in 2009 as a result of higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, favourable foreign exchange rates, higher capitalized interest, and lower interest rates.

Non-controlling interests decreased for the three and six months ended June 30, 2010 compared to the same period in 2009 primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac.

The income tax recovery increased for the three and six months ended June 30, 2010 compared to the same period in 2009 due to the recovery recorded related to the resolution of certain outstanding tax matters during the second quarter of 2010, partially offset by higher pre-tax earnings.

CASH FLOW

Cash flow from operating activities for the three months ended June 30, 2010 increased $41 million compared to the same period in 2009 primarily due to higher cash earnings, partially offset by unfavourable changes in working capital related to the timing of receiving certain tax related recoveries, which we expect to receive before the end of the year.

For the six months ended June 30, 2010, cash flow from operating activities increased $132 million due to higher cash earnings and favourable changes in working capital due to favourable inventory movements and the timing of operational payments, partially offset by the timing of receiving certain tax related recoveries, which we expect to receive before the end of the year.

Free cash flow for the three and six months ended June 30, 2010 increased $52 million and $172 million, respectively, compared to the same period in 2009 due to higher cash earnings and lower sustaining capital expenditures.

SIGNIFICANT EVENTS

Three months ended June 30, 2010

Resolution of Tax Matters

During the quarter, we recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense also decreased by $14 million as a result of associated interest recoveries. Cash from the resolution of these tax matters is expected to be received before the end of the year.

Project Pioneer

On June 28, 2010, we announced that Enbridge Inc. will officially participate in the development of Project Pioneer, Canada's first fully-integrated carbon capture and storage ("CCS") project involving retro-fitting a coal-fired generation plant.

Chief Financial Officer

On June 18, 2010, we announced that Brett Gellner was appointed chief financial officer, succeeding Brian Burden, who has made a personal decision to retire from the Corporation. Mr. Burden will assist Mr. Gellner with the transition through Sept. 30, 2010.

Sundance Unit 3 Outage

On June 7, 2010, we announced an outage at Unit 3 of our Sundance facility ("Unit 3"), due to the mechanical failure of critical generator components. Unit 3 returned to expected capability levels on June 23, 2010, but is expected to operate at a reduced capability. As a result of the outage and subsequent derate, second quarter production has been reduced by 367 GWh, and full year production is expected to decline by approximately 532 GWh. Unit 3 is expected to return to full capability after a major maintenance outage is completed in 2012.

In response to this event, we gave notice of a High Impact Low Probability ("HILP") Force Majeure Event to the Power Purchase Arrangement ("PPA") Buyers and the Balancing Pool. As at the date of this report, a response has not been received from the Balancing Pool as to our claim of HILP, and although no reassurance can be given, we believe that the Balancing Pool will confirm our position in due course. During the second quarter, we recorded an after-tax charge of $13 million, or 50 per cent of the penalties to June 30, 2010, representing the amount of penalties we are currently required to pay to the PPA Buyers pending a resolution of this matter.

Dividend Reinvestment and Share Purchase ("DRASP")

On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. Under the terms of our DRASP plan, participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. The Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

Centralia Thermal Memorandum of Understanding ("MOU")

On April 26, 2010, we announced that we signed an MOU with the State of Washington to enter discussions to develop an agreement to significantly reduce greenhouse gas ("GHG") emissions from the Centralia Thermal plant, and to provide replacement capacity by 2025. The MOU also recognizes the need to protect the value that Centralia Thermal brings to our shareholders. Details on the results of these discussions will be provided as they become available.

Six months ended June 30, 2010

Decommissioning of Wabamun Plant

On March 31, 2010, we fully retired all units of the Wabamun plant as part of our previously-announced shut down. Over the next several years, we will complete the Wabamun plant remediation and reclamation work as approved by the Government of Alberta. Based on our review of our schedule and detailed costing of the decommissioning and reclamation activities, the asset retirement obligation associated with the Wabamun plant has been reduced by $14 million with the offset recorded as a recovery in depreciation.

Senior Notes Offering

On March 12, 2010, we completed our offering of U.S.$300 million senior notes maturing in 2040 and bearing an interest rate of 6.50 per cent. The net proceeds from the offering were used to repay borrowings under existing credit facilities and for general corporate purposes.

Summerview 2

On Feb. 23, 2010, our 66 megawatt ("MW") Summerview 2 wind farm began commercial operations on budget and ahead of schedule. The total cost of the project was $123 million.

Kent Hills Expansion

On Jan. 11, 2010, we announced that we had been awarded a 25-year contract to provide an additional 54 MW of wind power to New Brunswick Power Distribution and Customer Service Corporation. Under the agreement, we will expand our existing 96 MW Kent Hills wind facility to a total of 150 MW. The total capital cost of the project is estimated to be $100 million and is expected to begin commercial operations by the end of 2010. Natural Forces, who currently owns a 17 per cent interest in the existing Kent Hills wind facility, will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

Change in Economic Useful Life

Management conducted a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, our economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $7 million and $12 million for the three and six months ended June 30, 2010, respectively, compared to the same period in 2009. The estimated annual pre-tax impact of this change is $29 million and will be reflected in depreciation expense and cost of goods sold.

Management continues to perform the comprehensive review on other assets. Any other adjustments resulting from this review will be reflected in future periods.

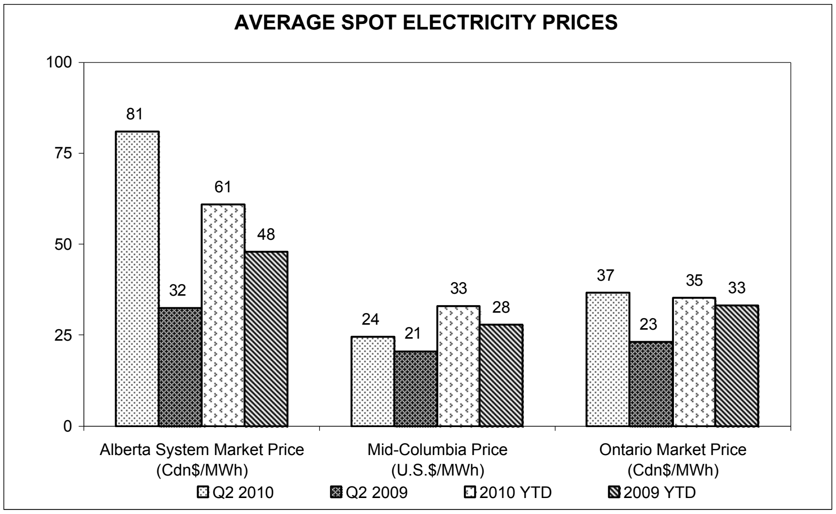
BUSINESS ENVIRONMENT

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 operate in are Western Canada, the Pacific Northwest, 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 2009 Annual Report.

Electricity Prices

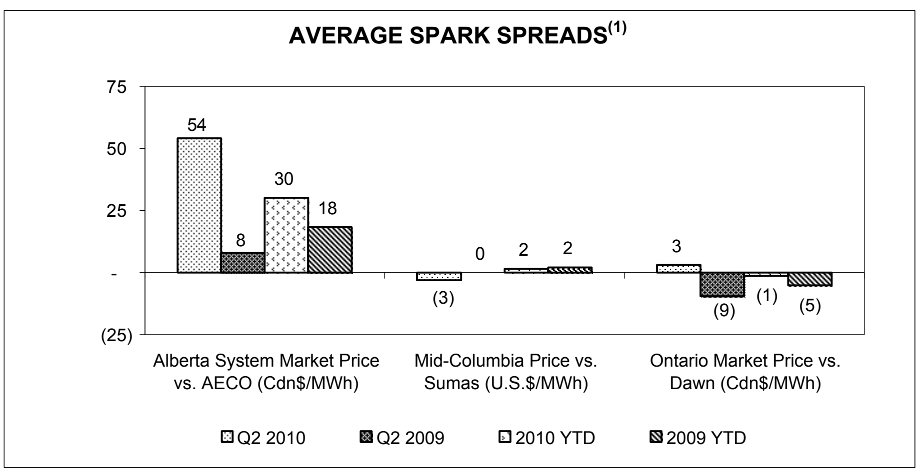
Please refer to the Business Environment section of the 2009 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the three and six months ended June 30, 2010 and 2009 in our three major markets are shown in the following graphs.



For the three and six months ended June 30, 2010, average spot prices increased in Alberta due to lower available supply as a result of the retirement of our Wabamun facility and from significant transmission work that was performed during the second quarter. Prices in the Pacific Northwest increased due to higher regional natural gas prices and low water conditions. Prices in Ontario were higher due to higher regional natural gas prices, higher demand levels as a result of above-average weather temperatures, and lower hydro generation.

During the second quarter of 2010, our consolidated power portfolio was 95 per cent contracted through the use of PPAs and other long-term contracts, which provide stability to future earnings. 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 in 2010 ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and from U.S.$50-$55 per MWh in the Pacific Northwest.



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

For the three and six months ended June 30, 2010, average spark spreads increased in Alberta due to higher power prices. Spark spreads in the Pacific Northwest decreased slightly due to gas prices increasing more than power prices. Ontario spark spreads were higher due to power prices increasing more than gas prices.

GENERATION: *Owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. During the first quarter of 2010, we began commercial operations at Summerview 2, a 66 MW expansion of our Summerview wind farm in southern Alberta. On March 31, 2010, we decommissioned our 279 MW Wabamun plant. At June 30, 2010, Generation had 8,986 MW of gross generating capacity[1] in operation (8,562 MW net ownership interest) and 412 MW net under construction. 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 2009 Annual Report.*

The results of the Generation segment are as follows:

3 months ended June 30	**2010 Total**	**2010 Per installed MWh**	2009 Total	2009 Per installed MWh
Revenues	**582**	**29.65**	570	31.12
Fuel and purchased power	**229**	**11.66**	239	13.05
Gross margin	**353**	**17.99**	331	18.07
Operations, maintenance, and administration	**150**	**7.64**	172	9.39
Depreciation and amortization	**113**	**5.76**	113	6.17
Taxes, other than income taxes	**8**	**0.41**	7	0.38
Intersegment cost allocation	**2**	**0.10**	8	0.44
Operating expenses	**273**	**13.91**	300	16.38
Operating income	**80**	**4.08**	31	1.69
Installed capacity (GWh)	**19,626**		18,315	
Production (GWh)	**10,201**		9,656	
Availability (%)	**81.9**		82.8	

6 months ended June 30	**2010 Total**	**2010 Per installed MWh**	2009 Total	2009 Per installed MWh
Revenues	**1,294**	**32.65**	1,311	35.99
Fuel and purchased power	**551**	**13.90**	614	16.86
Gross margin	**743**	**18.75**	697	19.14
Operations, maintenance and administration	**288**	**7.27**	318	8.73
Depreciation and amortization	**212**	**5.35**	224	6.15
Taxes, other than income taxes	**14**	**0.35**	12	0.33
Intersegment cost allocation	**3**	**0.08**	16	0.44
Operating expenses	**517**	**13.05**	570	15.65
Operating income	**226**	**5.70**	127	3.49
Installed capacity (GWh)	**39,636**		36,422	
Production (GWh)	**23,115**		21,829	
Availability (%)	**86.7**		84.6	

(1) We measure capacity as net maximum capacity (see glossary 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.

Production and Gross Margins

Generation's production volumes, fuel and purchased power costs, and gross margins based on geographical regions are presented below.

3 months ended June 30, 2010	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	5,601	7,659	184	85	99	24.02	11.10	12.93
Gas	1,060	1,227	59	18	41	48.08	14.67	33.41
Renewables	569	2,721	43	2	41	15.80	0.74	15.06
Total Western Canada	**7,230**	**11,607**	**286**	**105**	**181**	**24.64**	**9.05**	**15.59**
Gas	963	1,638	103	59	44	62.88	36.02	26.86
Renewables	300	1,326	29	3	26	21.87	2.26	19.61
Total Eastern Canada	**1,263**	**2,964**	**132**	**62**	**70**	**44.53**	**20.92**	**23.61**
Coal	946	3,005	102	53	49	33.94	17.64	16.30
Gas	433	1,680	33	7	26	19.64	4.17	15.47
Renewables	329	370	29	2	27	78.38	5.41	72.97
Total International	**1,708**	**5,055**	**164**	**62**	**102**	**32.44**	**12.27**	**20.17**
	10,201	**19,626**	**582**	**229**	**353**	**29.65**	**11.66**	**17.99**

3 months ended June 30, 2009	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	6,008	8,160	198	88	110	24.26	10.78	13.48
Gas	946	1,172	48	15	33	40.96	12.80	28.16
Renewables	432	2,080	27	3	24	12.98	1.44	11.54
Total Western Canada	7,386	11,412	273	106	167	23.92	9.29	14.63
Gas	831	1,638	88	53	35	53.72	32.36	21.36
Renewables	59	210	5	-	5	23.81	-	23.81
Total Eastern Canada	890	1,848	93	53	40	50.32	28.68	21.65
Coal	372	3,845	108	54	54	28.09	14.04	14.05
Gas	671	840	62	21	41	73.81	25.00	48.81
Renewables	337	370	34	5	29	91.89	13.51	78.38
Total International	1,380	5,055	204	80	124	40.36	15.83	24.53
	9,656	18,315	570	239	331	31.12	13.05	18.07

6 months ended June 30, 2010	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	12,424	15,837	383	147	236	24.18	9.28	14.89
Gas	2,061	2,386	117	43	74	49.04	18.02	31.02
Renewables	1,174	5,465	75	4	71	13.72	0.73	12.98
Total Western Canada	**15,659**	**23,688**	**575**	**194**	**381**	**24.27**	**8.19**	**16.08**
Gas	1,760	3,258	215	120	95	65.99	36.83	29.16
Renewables	634	2,636	60	3	57	22.76	1.14	21.62
Total Eastern Canada	**2,394**	**5,894**	**275**	**123**	**152**	**46.66**	**20.87**	**25.79**
Coal	3,525	5,977	328	207	121	54.88	34.63	20.25
Gas	935	3,340	65	24	41	19.46	7.19	12.27
Renewables	602	737	51	3	48	69.20	4.07	65.13
Total International	**5,062**	**10,054**	**444**	**234**	**210**	**44.16**	**23.27**	**20.89**
	23,115	**39,636**	**1,294**	**551**	**743**	**32.65**	**13.90**	**18.75**

6 months ended June 30, 2009	Production (GWh)	Installed (GWh)	Revenue	Fuel & purchased power	Gross margin	Revenue per installed MWh	Fuel & purchased power per installed MWh	Gross margin per installed MWh
Coal	11,944	16,224	374	164	210	23.05	10.11	12.94
Gas	2,040	2,331	113	43	70	48.48	18.45	30.03
Renewables	932	4,137	59	4	55	14.26	0.97	13.29
Total Western Canada	14,916	22,692	546	211	335	24.06	9.30	14.76
Gas	1,769	3,258	202	126	76	62.00	38.67	23.33
Renewables	114	417	9	-	9	21.58	-	21.58
Total Eastern Canada	1,883	3,675	211	126	85	57.41	34.29	23.13
Coal	3,028	6,818	358	221	137	52.51	32.41	20.10
Gas	1,350	2,500	129	45	84	51.60	18.00	33.60
Renewables	652	737	67	11	56	90.91	14.93	75.98
Total International	5,030	10,055	554	277	277	55.10	27.55	27.55
	21,829	36,422	1,311	614	697	35.99	16.86	19.14

Western Canada

Our Western Canada assets consist of coal, natural gas, hydro, biomass, and wind facilities. Refer to the Discussion of Segmented Results section of our 2009 Annual Report for further details on our Western operations.

The primary factors contributing to the change in production for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30	6 months ended June 30
	(GWh)	(GWh)
Production, 2009	7,386	14,916
Lower planned outages at Keephills	462	865
Higher merchant volumes due to Sundance 5 uprate	116	230
Higher wind volumes primarily due to the acquisition of Canadian Hydro	70	176
Higher hydro volumes	100	65
(Higher) lower planned outages at Sundance	(142)	61
Decommissioning of Wabamun	(457)	(457)
Higher unplanned outages at Sundance	(356)	(82)
Higher unplanned outages at Sheerness	(19)	(69)
Higher (lower) PPA customer demand	38	(51)
Higher (lower) production at natural gas-fired facilities	50	(44)
Other	(18)	49
Production, 2010	**7,230**	**15,659**

The primary factors contributing to the change in gross margin for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30	6 months ended June 30
Gross margin, 2009	167	335
Lower planned outages at Keephills	11	36
Higher wind volumes primarily due to the acquisition of Canadian Hydro	8	11
Higher hydro volumes and prices	15	10
(Higher) lower planned outages at Sundance	(3)	10
Higher merchant volumes due to Sundance 5 uprate	2	7
(Higher) lower unplanned outages at Sundance	(18)	(1)
Unfavourable pricing	(4)	(19)
Decommissioning of Wabamun	(6)	(6)
Lower (higher) coal costs	3	(3)
Higher unplanned outages at Sheerness	(1)	(5)
Other	7	6
Gross margin, 2010	**181**	**381**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2009 Annual Report for further details on our Eastern operations.

Production for the three and six months ended June 30, 2010 increased 373 GWh and 511 GWh, respectively, primarily due to higher wind volumes as a result of the acquisition of Canadian Hydro.

For the three and six months ended June 30, 2010, gross margin increased $30 million and $67 million, respectively, due to higher wind volumes as a result of the acquisition of Canadian Hydro and the new agreement with the OPA at our Sarnia regional cogeneration power plant that came into effect in the third quarter of 2009.

International

Our International assets consist of coal, natural gas, hydro, and geothermal facilities in various locations in the United States, and natural gas assets in Australia. Refer to the Discussion of Segmented Results section of our 2009 Annual Report for further details on our International operations.

The primary factors contributing to the change in production for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30 (GWh)	6 months ended June 30 (GWh)
Production, 2009	1,380	5,030
Economic dispatching at Centralia Thermal	978	978
Expiration of Saranac contract	(214)	(357)
Higher planned outages at Centralia Thermal	(303)	(303)
Higher unplanned outages at Centralia Thermal	(100)	(178)
Lower production at geothermal facilities	(53)	(93)
Higher (lower) production at natural gas-fired facilities	23	(11)
Other	(3)	(4)
Production, 2010	**1,708**	**5,062**

The primary factors contributing to the change in gross margin for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30	6 months ended June 30
Gross margin, 2009	124	277
Expiration of Saranac contract	(19)	(42)
Unfavourable foreign exchange	(11)	(29)
Economic dispatching at Centralia Thermal	(5)	(5)
Mark-to-market movements	(3)	(3)
Higher planned and unplanned outages at Centralia Thermal	(1)	(3)
Favourable pricing	18	16
Other	(1)	(1)
Gross margin, 2010	**102**	**210**

The long-term contract between our Saranac facility and New York State Electric and Gas expired in June 2009. The facility now operates under a combined capacity and merchant dispatch contract. As the facility was depreciated on a unit of production basis, there is a corresponding $5 million and $13 million decrease in depreciation expense from this lower level of production for the three and six months ended June 30, 2010, respectively. Further, as a portion of the facility is owned by a third party, there is also a decrease in earnings attributable to non-controlling interests. The net pre-tax earnings impact of the expiration of this contract is a decrease of approximately $7 million and $10 million for the three and six months ended June 30, 2010, respectively.

Operations, Maintenance and Administration Expense

OM&A costs for the three and six months ended June 30, 2010 decreased compared to the same period in 2009 due to lower planned outages and favourable foreign exchange rates, partially offset by acquisition of Canadian Hydro.

Depreciation Expense

The primary factors contributing to the change in depreciation expense for the three and six months ended June 30, 2010 are presented below:

	3 months ended June 30	6 months ended June 30
Depreciation and amortization expense, 2009	113	224
Reduction in decommissioning costs at Wabamun	-	(14)
Expiration of Saranac long-term contract	(5)	(13)
Favourable foreign exchange	(4)	(10)
Change in useful lives	(7)	(12)
Increased asset base primarily due to the acquisition of Canadian Hydro	16	36
Other	-	1
Depreciation and amortization expense, 2010	**113**	**212**

ENERGY TRADING: *Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. Achieving a positive gross margin while remaining within Value at Risk ("VaR") limits is a key measure of Energy Trading's activities.*

Energy Trading is responsible for the execution management of certain commercial activities for our current generating assets. Energy Trading also manages available merchant generating capacity as well as the fuel and transmission needs of the Generation business by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas, coal, and transmission capacity. 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 2009 Annual Report.

The results of the Energy Trading segment are as follows:

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Gross margin	**-**	15	**14**	30
Operations, maintenance, and administration	**4**	10	**8**	16
Depreciation and amortization	**1**	-	**1**	1
Intersegment cost recovery	**(2)**	(8)	**(3)**	(16)
Operating expenses	**3**	2	**6**	1
Operating (loss) income	**(3)**	13	**8**	29

For the three and six months ended June 30, 2010, gross margin decreased relative to the same period in 2009 due to reduced margins in the eastern region resulting from lower margins captured on regional spread strategies and power congestion constraints. The western region positions were negatively impacted by June precipitation and the resulting downward market pricing effects, partially offset by Alberta market pricing volatility and profitable directional positions held.

For the three and six months ended June 30, 2010, OM&A costs and the intersegment fee decreased relative to the same period in 2009 as a result of support costs previously recognized in OM&A and recovered through the intersegment fee being directly recorded in the Generation segment in 2010.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Interest on debt	**61**	43	**118**	86
Interest income from resolution of certain outstanding tax matters	**(14)**	-	**(14)**	-
Capitalized interest	**(13)**	(9)	**(22)**	(17)
Interest income	**(1)**	(1)	**(1)**	(3)
Net interest expense	**33**	33	**81**	66

The change in net interest expense for the three and six months ended June 30, 2010, compared to the same period in 2009 is shown below:

	3 months ended June 30	6 months ended June 30
Net interest expense, 2009	33	66
Higher debt levels	24	45
Interest income from resolution of certain outstanding tax matters	(14)	(14)
Favourable foreign exchange	(3)	(8)
Higher capitalized interest	(4)	(5)
Lower interest rates	(3)	(5)
Lower interest income	-	2
Net interest expense, 2010	**33**	**81**

OTHER INCOME

During the first quarter of 2009, we settled an outstanding commercial issue that was related to our previously held Mexican equity investment and recorded as a pre-tax gain of $7 million. During the second quarter of 2009, we recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm.

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three and six months ended June 30, 2010 decreased $3 million and $12 million, respectively, primarily due to lower earnings at CE Generation, LLC ("CE Gen") as a result of the expiration of the long-term contract at our Saranac facility.

INCOME TAXES

A reconciliation of income taxes and effective tax rates on comparable income (loss) before income taxes is presented below:

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Earnings (loss) before income taxes	**15**	(26)	**99**	20
Settlement of commercial issue	**-**	-	**-**	(7)
Change in life of Centralia parts	**-**	-	**-**	2
Comparable earnings (loss) before income taxes	**15**	(26)	**99**	15
Income tax recovery	**(36)**	(20)	**(19)**	(16)
Income tax recovery related to the resolution of certain outstanding tax matters	**30**	-	**30**	-
Income tax expense on settlement of commercial issue	**-**	-	**-**	(1)
Income tax expense on change in life of Centralia parts	**-**	-	**-**	1
Income tax (recovery) expense excluding non-comparable items	**(6)**	(20)	**11**	(16)
Effective tax rate on comparable earnings (loss) before income taxes (%)	**(40)**	77	**11**	(107)

The income tax recovery excluding non-comparable items decreased for the three months ended June 30, 2010 and the income tax expense excluding non-comparable items increased for the six months ended June 30, 2010 compared to the same period in 2009 primarily due to higher pre-tax earnings.

The effective tax rate on comparable earnings (loss) before income taxes decreased for the three months ended June 30, 2010 and increased for the six months ended June 30, 2010 compared to the same period in 2009 primarily due to certain deductions that do not fluctuate with earnings and a change in the mix of jurisdictions where pre-tax income is earned.

FINANCIAL POSITION

The following chart highlights significant changes in the Consolidated Balance Sheets from Dec. 31, 2009 to June 30, 2010:

	Increase/ (Decrease)	Primary factors explaining change
Cash and cash equivalents	(39)	Timing of operational and debt payments
Accounts receivable	(49)	Timing of customer receipts
Income taxes receivable	72	Expected receivable related to the resolution of certain outstanding tax matters
Inventory	13	Lower production at coal facilities
Long-term receivable	(49)	Now included in income taxes receivable
Risk management assets (current and long-term)	110	Price movements
Property, plant, and equipment, net	164	Capital additions, partially offset by depreciation expense
Intangible assets	(14)	Amortization expense
Accounts payable and accrued liabilities	(78)	Timing of payments, combined with lower operational expenditures
Collateral received	26	Collateral collected from counterparties associated with their obligations as a result of a change in forward prices
Long-term debt (including current portion)	295	Issuance of U.S.$300 senior notes, partially offset by repayments of other long-term debt
Risk management liabilities (current and long-term)	(38)	Price movements
Asset retirement obligation (including current portion)	(26)	Revised cost estimate of the decommissioning of our Wabamun plant and foreign exchange
Non-controlling interests	(17)	Distributions in excess of earnings attributable to non-controlling interests
Shareholders' equity	46	Net earnings, and movements in AOCI, partially offset by dividends declared

FINANCIAL INSTRUMENTS

Refer to *Note 7* of the notes to the consolidated financial statements within our 2009 Annual Report and *Note 6* of the interim consolidated financial statements as at and for the three and six months ended June 30, 2010 for details on Financial Instruments. Refer to the Risk Management section of our 2009 Annual Report for further details on our risks and how we manage them. Our risk management profile and practices have not changed materially from Dec. 31, 2009.

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market observable data is not available. These are defined under GAAP 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 or upon internally developed assumptions or inputs. Our Level III fair values are determined using valuation techniques with inputs that are based on historical 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.

As a result of the acquisition of Canadian Hydro, 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 a specified price with counterparties that we believe to be creditworthy.

At June 30, 2010, Level III financial instruments had a net liability carrying value of $18 million (Dec. 31, 2009 – $26 million).

STATEMENTS OF CASH FLOWS

The following charts highlight significant changes in the Consolidated Statements of Cash Flows for the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009:

3 months ended June 30	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**84**	49	
Provided by (used in):			
Operating activities	**98**	57	Higher cash earnings of $90 million, partially offset by unfavourable changes in working capital of $49 million, primarily due to the timing of receiving certain tax related recoveries, which we expect to receive before the end of the year.
Investing activities	**(344)**	(355)	Decrease in the amount of collateral repaid to counterparties of $18 million.
Financing activities	**207**	304	Lower borrowings required as a result of higher cash earnings and a decrease in the amount of collateral repaid to counterparties.
Translation of foreign currency cash	**(2)**	(1)	
Cash and cash equivalents, end of period	**43**	54	

6 months ended June 30	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**82**	50	
Provided by (used in):			
Operating activities	**272**	140	Higher cash earnings of $89 million and favourable changes in working capital of $43 million due to favourable movements in inventory and the timing of operational payments, partially offset by the timing of receiving certain tax related recoveries, which we expect to receive before the end of the year.
Investing activities	**(397)**	(292)	Decrease in the amount of collateral received from counterparties of $94 million.
Financing activities	**89**	156	Lower borrowings as a result of higher cash earnings and favourable working capital changes, partially offset by reductions in collateral received.
Translation of foreign currency cash	**(3)**	-	
Cash and cash equivalents, end of period	**43**	54	

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 a 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 partners, and interest and principal payments on debt securities.

Debt

Recourse and non-recourse debt totalled $4.7 billion at June 30, 2010 compared to $4.4 billion at Dec. 31, 2009. Total debt increased from Dec. 31, 2009 primarily due to growth related capital expenditures and unfavourable working capital movements.

Credit Facilities

At June 30, 2010, we have a total of $2.1 billion (Dec. 31, 2009 – $2.1 billion) of committed credit facilities of which $0.8 billion (Dec. 31, 2009 – $0.7 billion) is available, subject to customary borrowing conditions. At June 30, 2010, the $1.3 billion (Dec. 31, 2009 – $1.4 billion) of credit utilized under these facilities is comprised of actual drawings of $1.0 billion (Dec. 31, 2009 – $1.1 billion) and of letters of credit of $0.3 billion (Dec. 31, 2009 – $0.3 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility, which matures in 2012, with the remainder comprised of bilateral credit facilities which mature between the fourth quarter of 2011 and 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Share Capital

On July 28, 2010, we had 220 million common shares outstanding.

At June 30, 2010, we had 218.8 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended June 30, 2010, 0.2 million (June 30, 2009 – nil) common shares were issued for proceeds of $3 million (June 30, 2009 – nil). During the six months ended June 30, 2010, 0.4 million (June 30, 2009 – 0.2 million) common shares were issued for proceeds of $4 million (June 30, 2009 – nil).

During the quarter, the Corporation issued 0.2 million common shares for proceeds of $3 million under the terms of the DRASP plan.

During the three and six months ended June 30, 2010 and 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid program prior to its expiry on May 6, 2010.

We employ a variety of stock-based compensation to align employee and corporate objectives. At June 30, 2010, we had 2.3 million outstanding employee stock options (Dec. 31, 2009 – 1.5 million), reflecting 0.9 million stock options granted on Feb. 1, 2010, at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2011, and expire after 10 years. During the three months ended June 30, 2010, a nominal number of options also expired, or were exercised or cancelled (June 30, 2009 – 0.1 million cancelled). During the six months ended June 30, 2010, a nominal number of options also expired, or were exercised or cancelled (June 30, 2009 – 0.1 million expired, 0.1 million cancelled).

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At June 30, 2010, we provided letters of credit totalling $318 million (Dec. 31, 2009 – $334 million) and cash collateral of $28 million (Dec. 31, 2009 – $27 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Balance Sheets under “Risk Management Liabilities” and “Asset Retirement Obligation.”

CLIMATE CHANGE AND THE ENVIRONMENT

Canada

On June 23, 2010, the Government of Canada announced plans for regulating GHG emissions from the coal-fired power sector. The plan becomes effective in 2015 and requires existing coal-fired plants to meet a natural gas emissions performance standard by their 45th year of operation, or the end of their PPA term, whichever is later. If the coal-fired plants do not meet the required performance standard by that time, they are to cease operations. Until then, the plants would not be subject to any federal GHG compliance costs.

While the above development provides regulatory clarity for future capital decision-making, there are some issues that will have to be resolved, including how transition costs are recovered by generators, the impacts on Alberta PPAs, standards for emission requirements for natural gas-fired facilities, and how CCS will continue to be supported. The effect of this proposal on the Alberta deregulated market and PPA structure must also be considered. These matters are currently under discussion with both the federal and provincial governments.

United States

In the U.S., the future direction on climate change has not been resolved and may remain unresolved. Legislative initiatives in the Senate continue to emerge but are not yet adopted. We do not expect much clarity on any initiative until 2011. Canada continues to state that it will follow the U.S. lead and timing on all sectors except for the coal-fired power sector.

On June 21, 2010, the U.S. Environmental Protection Agency (“EPA”) released draft regulations on the handling and disposal of coal ash in wet storage ponds. This regulation would not affect our Centralia plant as it does not have ash lagoons and the majority of the ash from Centralia is being sold as a by-product.

On June 18, 2010, we finalized our negotiated agreement with Washington State for managing nitrogen oxide and mercury emissions. We believe we are well positioned to meet the requirements and deadlines outlined in the agreement. Separately, on April 26, 2010, we signed a Memorandum of Understanding with Washington State to develop an agreement to reduce GHG emissions from the Centralia plant and provide replacement capacity by 2025. This action is consistent with the Governor's Executive Order to reduce the GHG emissions of the plant by approximately 50 per cent of current levels by that time.

Recent changes to environmental regulations may materially adversely affect us. As indicated under "Risk Factors" in our Annual Information Form, many of our activities and properties are subject to environmental requirements, as well as changes in or liabilities under these requirements, which may have a materially adverse affect upon our consolidated financial results.

2010 OUTLOOK

In 2010, we anticipate double digit growth in comparable earnings per share based upon the significant factors that are discussed below.

Business Environment

Power Prices

For the remainder of 2010, power prices are expected to be at or slightly above 2009 levels due to low natural gas prices. In Alberta, the longer-term fundamentals of the market remain strong and increased production at the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices and the economy will be the main drivers behind the recovery of power prices. Natural gas prices are expected to remain low through 2011 and 2012.

Environmental Legislation

With the Government of Canada's announcement on plans for regulating GHG emissions from the coal-fired power sector on June 23, 2010, there may be some regulatory clarity for our coal-fired facilities in the future. The finalization of GHG emission regulations for the coal-fired power sector is expected in 2011. For other Canadian power sectors, the federal government has expressed its intention to coordinate the timing and structure of its GHG regulatory framework with the U.S. In the U.S. it is not clear if climate change legislation will prevail or if regulation will instead be applied by the EPA. Each of these outcomes could create widely different results for the energy industry in the U.S., and indirectly for Canada's regulatory approach.

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

Economic Environment

While we expect our results from operations in 2010 to be impacted by the current economic environment, we expect that this impact will be somewhat mitigated by the contracted production and prices through our Alberta PPAs and other long-term contracts.

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 2010 due to the commissioning of Kent Hills 2. Overall production for 2010 is expected to increase due to lower planned and unplanned outages across the fleet and the acquisition of Canadian Hydro, partially offset by the decommissioning of Wabamun. Availability for 2010 is expected to increase due to lower planned and unplanned outages across the fleet, with the overall fleet availability for 2010 expected to be between approximately 89 to 90 per cent. The decrease in availability from prior estimates reflects the anticipated impact of the outage at Unit 3 of our Sundance facility.

Commodity Hedging

Through the use of Alberta PPAs, long-term contracts, and other short-term physical and financial contracts, on average approximately 75 per cent of our capacity is contracted over the next seven years. On an aggregated portfolio basis we target being up to 90 per cent contracted for the upcoming year, stepping down to 70 per cent in the fourth year. As at the end of the second quarter, approximately 92 per cent of our 2010 capacity was contracted. The average price of our short-term physical and financial contracts in 2010 ranges from $60-$65 per MWh in Alberta, and from U.S.$50-$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 mines are minimized through the application of standard costing. Coal costs for 2010, on a standard cost basis, are expected to increase five to 10 per cent compared to the prior year as a result of increased depreciation due to mine capital investment and higher diesel costs.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2010 is expected to be consistent with 2009.

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 is expected to reduce the year to year volatility of prices going forward and may lead to greater opportunities to hedge our natural gas price exposure with longer term contracts.

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 per MWh of installed capacity fluctuate by quarter and are dependent on the timing and nature of maintenance activities. OM&A costs for 2010 are expected to be slightly lower than 2009 as costs related to Canadian Hydro are expected to be more than offset by lower planned maintenance, operational synergies, and productivity measures. OM&A costs per installed MWh for 2010 are expected to decrease primarily as a result of lower planned maintenance and an increase in installed capacity due to the acquisition of Canadian Hydro.

Energy Trading

Earnings from our Energy Trading segment are affected by prices in the market, positions taken, and the duration of those positions. We continuously monitor both the market and our exposure to enhance earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading to contribute between $40 million and $60 million in gross margin. The annual objective for Energy Trading gross margin contribution has decreased from prior estimates to reflect the second quarter results.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar by offsetting foreign denominated assets with foreign denominated liabilities and 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 2010 is expected to be higher than 2009 mainly due to higher debt balances. 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, there may be the need for additional liquidity. To mitigate this liquidity risk, we expect to maintain $2.1 billion of committed credit facilities and will monitor our exposures and obligations to ensure we have sufficient liquidity to meet our requirements.

Accounting Estimates

A number of our accounting estimates, including those outlined in the Critical Accounting Policies and Estimates section of our 2009 Annual MD&A, are based on the current economic environment and outlook. While we currently do not anticipate significant changes to these estimates, 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. The unrealized gains or losses related to our risk management assets and liabilities are not expected to impact our future cash flows as they are generally settled at the contracted prices.

Income Taxes

The effective tax rate for 2010, excluding recoveries related to the resolution of certain outstanding tax matters, is expected to be approximately 20 to 25 per cent.

Capital Expenditures

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

Growth Capital Expenditures

We have six significant growth capital projects that are currently in progress with targeted completion dates between Q4 2010 and Q4 2012. A summary of each of these significant projects is outlined below:

	Total Project		2010		Target	
Project	**Estimated spend**	**Incurred to date[(1)]**	**Estimated spend**	**Incurred to date[(1)]**	**completion date**	**Details**
Keephills 3	988	833	225 - 245	126	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Summerview 2	123	117	15 - 25	11	Commercial operations began Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	3	0 - 5	2	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	3	5 - 10	2	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	99	95 - 105	72	Q1 2011	A 69 MW wind farm in southern Alberta
Bone Creek	48	18	40 - 45	14	Q1 2011	An 18 MW hydro facility in British Columbia
Kent Hills 2	100	61	80 - 85	43	Q4 2010	A 54 MW expansion of our wind farm in New Brunswick
Total growth	**1,462**	**1,134**	**460 - 520**	**270**		

Our estimated spend in 2010 for Keephills Unit 1 has decreased by $5 million and our estimated spend in 2010 for Keephills Unit 2 has increased by $5 million to more accurately reflect the expected timing of related costs. The total estimated spend in 2010 for growth capital projects has not changed.

Amounts disclosed in the above chart are shown net of any joint venture contributions received.

(1) Represents amounts incurred as of June 30, 2010, including the impact of project hedges.

Sustaining Capital Expenditures

For 2010, our estimate for total sustaining capital expenditures, net of any contributions received, is allocated among the following:

Category	Description	Expected cost	Incurred to date(1)
Routine capital	Expenditures to maintain our existing generating capacity	120 - 140	63
Productivity capital	Projects to improve power production efficiency	10 - 15	5
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	20 - 25	2
Planned maintenance	Regularly scheduled major maintenance	125 - 140	73
Total sustaining expenditures		**275 - 320**	143

The expected cost for mining equipment and land purchases has decreased compared to prior estimates to reflect the deferral of certain purchases to 2011. The expected cost for planned maintenance has decreased compared to prior estimates to reflect the expected timing of planned maintenance to be completed, primarily related to our natural gas-fired facilities.

Details of the 2010 planned maintenance program are outlined as follows:

	Coal	Gas	Renewables	Expected cost	Incurred to date(1)
Capitalized	70 - 75	30 - 35	25 - 30	**125 - 140**	73
Expensed	65 - 70	0 - 5	-	**65 - 75**	39
	135 - 145	30 - 40	25 - 30	**190 - 215**	112

	Coal	Gas	Renewables	Total	Incurred to date (1)
GWh lost	2,465 - 2,475	160 - 170	-	**2,625 - 2,645**	1,968

The expected cost for coal has increased compared to prior estimates to more accurately reflect actual costs expected to be incurred related to the turnaround on Unit 4 at our Sundance facility. The expected GWh to be lost for coal have increased compared to prior estimates to more accurately reflect the increased scope of work at Centralia Thermal and expectations for the remainder of the year.

The expected cost and GWh to be lost for gas decreased compared to prior estimates to reflect the expected timing of planned maintenance to be completed at our natural gas-fired facilities.

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing borrowing capacity, and capital markets. The funds required for committed growth and sustaining 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.

(1) Represents amounts incurred as of June 30, 2010.

RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at June 30, 2010, TAGP had received $57 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

For the period November 2002 to November 2012, one of our subsidiaries, TransAlta Cogeneration, L.P. ("TA Cogen"), entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. We entered into an offsetting contract and therefore have no risk other than counterparty risk.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards ("IFRS") Convergence

On May 8, 2009, the Accounting Standards Board re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. Our project to convert to IFRS consists of the following phases:

Phase	Description	Status
Diagnostic	In-depth identification and analysis of differences between Canadian GAAP and IFRS	Complete
Design and planning	Cross-functional, issue-specific teams analyze the key areas of convergence, and along with Information Technology and Internal Control resources, determine process, system, and financial reporting controls changes required for the conversion to IFRS	Complete
Solution development	Plans to address identified conversion issues are developed and tested in a controlled environment. Staff training programs and internal communication plans are implemented to communicate process changes as a result of the conversion to IFRS	In progress
Implementation	Processes required for dual reporting in 2010 and full convergence in 2011 are implemented in a live environment with change management in place for a successful transition to steady state	In progress

A steering committee monitors the progress and critical decisions of the transition to IFRS and continues to meet regularly. This committee includes representatives from Finance, Information Technology, Treasury, Investor Relations, Human Resources, and Operations. Quarterly updates are provided to the Audit and Risk Committee.

While IFRS uses a conceptual framework similar to Canadian GAAP and has many similarities to Canadian GAAP, there are several significant differences in accounting policies that must be addressed, which are expected to have a relatively modest impact on our consolidated financial results. Based on the work we've completed to date, the more significant impacts of IFRS to us are as follows:

Property, Plant, and Equipment ("PP&E")

- Key change in accounting: Major inspection costs, which are currently expensed, will be capitalized and depreciated over the period until the next major inspection.
- Income statement impact: Earnings will likely be less volatile.
- Balance sheet impact upon transition to IFRS: Increase in PP&E as previously expensed major inspection costs will be capitalized.
- Cash flow statement impact: Major inspection costs will be recorded as cash flows used in investing activities instead of as cash flows used in operating activities.
- Other differences: Additional disclosures reconciling the changes in individual classes of PP&E and accumulated depreciation will be required.

Asset Retirement Obligation ("ARO")

- Key change in accounting: AROs are revalued at the end of each accounting period using the current market interest rate instead of using historic rates.
- Income statement impact: Accretion expense will be classified as a finance (interest) cost under IFRS as opposed to an operating expense under Canadian GAAP, and revaluations will result in differences to the amounts expensed each period over the life of the asset to be remediated.
- Balance sheet impact upon transition to IFRS: Due to differences in discount rates, the opening balance for ARO will be different.
- Cash flow statement impact: None.

Post-Employment Defined Benefit Plans

- Key change in accounting: All actuarial gains and losses related to defined benefit plans will be recognized in other comprehensive income ("OCI").
- Income statement impact: Nothing significant.
- Balance sheet impact of transitioning to IFRS: Recognition of net cumulative actuarial losses of approximately $78 million (after-tax) in opening retained earnings.
- Cash flow statement impact: None.

Arrangements Containing Leases

- Key change in accounting: All contractual arrangements will be evaluated to determine if they contain a lease.
- Income statement impact: For those contracts that are determined to be leases, payments received under the contract will be recorded as finance (interest) income. The impact on net earnings is not expected to be significant.
- Balance sheet impact of transitioning to IFRS: For certain long-term contracts that are deemed to be finance leases, the associated PP&E will be removed from the Consolidated Balance Sheets and replaced with a long-term receivable representing the present value of lease payments to be received over the life of the contract.
- Cash flow impact: Payments received under the contract will be recorded as cash flows from financing activities instead of cash flows from operating activities.

Several elections are available under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* that assist with the transition to IFRS. At present, we expect to make use of several elections that will have the following effect:

- Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and tax, of $63 million, will be reset to zero;
- Share-based payments will only be applied to equity instruments outstanding at transition that were granted on or after Nov. 7, 2002, and which had not vested by the transition date;
- Business Combinations that occurred prior to Jan. 1, 2010 will continue to be measured and recorded at the Canadian GAAP amounts;
- All classes of PP&E and intangible assets will be measured at cost and not at fair value;
- We will use a simplified method to recalculate the cost of decommissioning assets included in PP&E;
- We will not adjust interest previously capitalized as part of PP&E under Canadian GAAP; and
- Amounts previously capitalized under Canadian GAAP to PP&E during the period they operated in rate-regulated environments, will not be restated.

However, as we implement our 2010 dual reporting, we continue to evaluate these and other transitional options available under IFRS 1, as well as the most appropriate long-term accounting policies available under other IFRSs.

In 2010, the International Accounting Standards Board ("IASB") is expected to issue new guidance on the accounting for joint ventures. Under the proposed guidance, certain joint ventures cannot be proportionately consolidated and must instead be accounted for as an equity investment on the Consolidated Balance Sheets with the associated net income or loss from these joint ventures being recorded as equity earnings on the Consolidated Statement of Earnings, with the cash flows exchanged between the parties reflected in the investing section of the Consolidated Statements of Cash Flows.

At this time, it is not anticipated that any other material new standards or amendments will be effective on convergence in 2011. However, the progress and recommendations of IASB projects for financial instruments, post-employment benefits, financial statement presentation, revenue recognition, and leases are being closely monitored to ensure that any potential adverse impacts to the convergence project are identified and can be minimized. As a result, the full impact of adopting IFRS on our financial position and future results cannot reasonably be determined at this time.

NON-GAAP MEASURES

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

Each business unit assumes responsibility for its operating results measured to gross margin and operating income. Operating income and gross margin provides management and investors with a measurement of operating performance which is readily comparable from period to period.

Net Earnings (Loss) Reconciliation

Gross margin and operating income are reconciled to net earnings (loss) below:

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Revenues	**582**	585	**1,308**	1,341
Fuel and purchased power	**229**	239	**551**	614
Gross margin	**353**	346	**757**	727
Operations, maintenance, and administration	**172**	207	**332**	381
Depreciation and amortization	**118**	118	**222**	235
Taxes, other than income taxes	**8**	7	**14**	12
Operating expenses	**298**	332	**568**	628
Operating income	**55**	14	**189**	99
Foreign exchange gain	**-**	2	**3**	3
Net interest expense	**(33)**	(33)	**(81)**	(66)
Other income	**-**	1	**-**	8
Earnings (loss) before non-controlling interests and income taxes	**22**	(16)	**111**	44
Non-controlling interests	**7**	10	**12**	24
Earnings (loss) before income taxes	**15**	(26)	**99**	20
Income tax recovery	**(36)**	(20)	**(19)**	(16)
Net earnings (loss)	**51**	(6)	**118**	36

Earnings (Loss) on a Comparable Basis

Presenting earnings on a comparable basis from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with results from prior periods. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

In calculating comparable earnings for 2010, we excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

In calculating comparable earnings for 2009, we excluded the settlement of an outstanding commercial issue that was recorded in other income as this was related to our previously held Mexican equity investment. The change in life of certain component parts at Centralia Thermal was also excluded from the calculation of comparable earnings in 2009 as it relates to the cessation of mining activities at the Centralia coal mine and conversion of Centralia to consuming solely third party supplied coal.

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Net earnings (loss)	**51**	(6)	**118**	36
Income tax recovery related to the resolution of certain outstanding tax matters	**(30)**	-	**(30)**	-
Settlement of commercial issue, net of tax	**-**	-	**-**	(6)
Change in life of Centralia parts, net of tax	**-**	-	**-**	1
Earnings (loss) on a comparable basis	**21**	(6)	**88**	31
Weighted average number of common shares outstanding in the period	**219**	198	**219**	198
Earnings (loss) on a comparable basis per share	**0.10**	(0.03)	**0.40**	0.16

EBITDA

Presenting 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.

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Operating income	**55**	14	**189**	99
Asset retirement obligation accretion per the Consolidated Statements of Cash Flows	**5**	6	**10**	12
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**122**	122	**232**	243
EBITDA	**182**	142	**431**	354

Funds from Operations and Cash Flow from Operating Activities

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

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Funds from operations	**184**	94	**374**	285
Change in non-cash operating working capital balances	**(86)**	(37)	**(102)**	(145)
Cash flow from operating activities	**98**	57	**272**	140
Weighted average number of common shares outstanding in the period	**219**	198	**219**	198
Cash flow from operating activities per share	**0.45**	0.29	**1.24**	0.71

Free Cash Flow (Deficiency)

Free cash flow represents the amount of cash generated by our business that is available to invest in growth initiatives, repay scheduled principal repayments of recourse debt, pay additional common share dividends, or repurchase common shares.

Sustaining capital expenditures for the three months ended June 30, 2010, represents total additions to PP&E per the Consolidated Statements of Cash Flows less $194 million ($193 million net of joint venture contributions) that we have invested in growth projects[2]. For the same period in 2009, we invested $172 million ($168 million net of joint venture contributions) in growth projects. For the six months ended June 30, 2010 and 2009, we invested $275 million ($270 million net of joint venture contributions) and $234 million ($225 million net of joint venture contributions), respectively, in growth projects.

(1) To calculate EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows in order to account for depreciation related to mine assets, which is included in cost of sales on the Consolidated Statements of Earnings (Loss) and Retained Earnings.
(2) The calculation of sustaining capital expenditures for the three and six months ended June 30, 2010 also excludes the impact of project hedges.

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

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Cash flow from operating activities	**98**	57	**272**	140
Add (Deduct):				
Sustaining capital expenditures	**(98)**	(109)	**(143)**	(178)
Dividends paid on common shares	**(64)**	(57)	**(123)**	(111)
Distributions paid to subsidiaries' non-controlling interests	**(15)**	(17)	**(29)**	(33)
Non-recourse debt repayments[1]	**(13)**	(17)	**(13)**	(18)
Other income	**-**	(1)	**-**	(8)
Free cash flow (deficiency)	**(92)**	(144)	**(36)**	(208)

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

SELECTED QUARTERLY INFORMATION

	Q3 2009	Q4 2009	Q1 2010	**Q2 2010**
Revenue	666	763	726	**582**
Net earnings	66	79	67	**51**
Basic and diluted earnings per share	0.34	0.37	0.31	**0.23**
Comparable earnings per share	0.34	0.40	0.31	**0.10**

	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Revenue	791	808	756	585
Net earnings (loss)	61	94	42	(6)
Basic and diluted earnings (loss) per share	0.31	0.47	0.21	(0.03)
Comparable earnings (loss) per share	0.32	0.40	0.18	(0.03)

Basic and diluted earnings (loss) per share and comparable earnings (loss) 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.

(1) Excludes debt repayments related to recourse debt that have been or will be refinanced with long-term debt issuances, consistent with our overall capital strategy.

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 June 30, 2010, 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 as well as 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 upgrades, and their attendant costs; expectations related to future earnings and cash flow from operating activities; expectations relating to the timing of the completion of the FEED study regarding CCS and the cost of the study; estimates of fuel supply and demand conditions and the costs of procuring fuel; our plans to invest in existing and new capacity, and the expected return on those investments; expectations for demand for electricity in both the short-term and long-term, and the resulting impact on electricity prices; expectations in respect of generation availability and production; expectations in terms of the cost of operations and maintenance, and the variability of those costs; our plans to install mercury control equipment at our Alberta Thermal operations and our initiative to reduce nitrogen oxide and mercury emissions from our Centralia Plant; expected governmental regulatory regimes and legislation, as well as the cost of complying with resulting regulations and laws; our trading strategy and the risk involved in these strategies; expectations relating to the renegotiation of certain of the collective bargaining agreements to which we are party; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; expectations for the outcome of existing or potential legal claims; and expectations for the ability to access capital markets at reasonable terms.

Factors that may adversely impact our forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) effects of weather; (viii) disruptions in the source of fuels, water, wind or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) energy trading risks; (xii) industry risk and competition; (xiii) fluctuations in the value of foreign currencies and foreign political risks; (xiv) need for additional financing; (xv) structural subordination of securities; (xvi) counterparty credit risk; (xvii) insurance coverage; (xviii) our provision for income taxes; (xix) legal proceedings involving the Corporation; (xx) reliance on key personnel (xxi) labour relations matters; and (xxii) development projects and acquisitions. The foregoing risk factors, among others, are described in further detail in the Risk Management section of our 2009 Annual Report and under the heading "Risk Factors" in our 2009 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 you that projected results or events will be achieved.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended June 30		6 months ended June 30	
Unaudited	**2010**	2009	**2010**	2009
Revenues	**582**	585	**1,308**	1,341
Fuel and purchased power	**229**	239	**551**	614
	353	346	**757**	727
Operations, maintenance, and administration	**172**	207	**332**	381
Depreciation and amortization *(Note 21)*	**118**	118	**222**	235
Taxes, other than income taxes	**8**	7	**14**	12
	298	332	**568**	628
	55	14	**189**	99
Foreign exchange gain	**-**	2	**3**	3
Net interest expense *(Notes 5 and 11)*	**(33)**	(33)	**(81)**	(66)
Other income *(Note 3)*	**-**	1	**-**	8
Earnings (loss) before non-controlling interests and income taxes	**22**	(16)	**111**	44
Non-controlling interests *(Note 4)*	**7**	10	**12**	24
Earnings (loss) before income taxes	**15**	(26)	**99**	20
Income tax recovery *(Note 5)*	**(36)**	(20)	**(19)**	(16)
Net earnings (loss)	**51**	(6)	**118**	36
Retained earnings				
Opening balance	**638**	673	**634**	688
Common share dividends	**64**	57	**127**	114
Closing balance	**625**	610	**625**	610
Weighted average number of common shares outstanding in the period	**219**	198	**219**	198
Net earnings (loss) per share, basic and diluted	**0.23**	(0.03)	**0.54**	0.18

See accompanying notes.

TRANSALTA CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions of Canadian dollars)

Unaudited	June 30, 2010	Dec. 31, 2009
Cash and cash equivalents *(Note 6)*	**43**	82
Accounts receivable *(Notes 6 and 19)*	**372**	421
Collateral paid *(Notes 6 and 7)*	**28**	27
Prepaid expenses	**25**	18
Risk management assets *(Notes 6 and 7)*	**213**	144
Income taxes receivable *(Note 9)*	**111**	39
Inventory *(Note 8)*	**103**	90
	895	821
Long-term receivables *(Note 9)*	**-**	49
Property, plant, and equipment		
Cost	**11,716**	11,721
Accumulated depreciation	**(3,974)**	(4,143)
	7,742	7,578
Goodwill *(Note 21)*	**434**	434
Intangible assets	**319**	333
Future income tax assets *(Note 2)*	**202**	234
Risk management assets *(Notes 6 and 7)*	**265**	224
Other assets *(Note 10)*	**107**	102
Total assets	**9,964**	9,775
Accounts payable and accrued liabilities *(Note 6)*	**443**	521
Collateral received *(Notes 6 and 7)*	**112**	86
Risk management liabilities *(Notes 6 and 7)*	**34**	45
Income taxes payable	**5**	10
Future income tax liabilities *(Note 2)*	**24**	45
Dividends payable	**65**	61
Current portion of long-term debt - recourse *(Notes 6 and 11)*	**232**	7
Current portion of long-term debt - non-recourse *(Notes 6 and 11)*	**22**	24
Current portion of asset retirement obligation *(Note 12)*	**37**	32
	974	831
Long-term debt - recourse *(Notes 6 and 11)*	**3,939**	3,857
Long-term debt - non-recourse *(Notes 6 and 11)*	**544**	554
Asset retirement obligation *(Note 12)*	**219**	250
Deferred credits and other long-term liabilities	**147**	136
Future income tax liabilities *(Note 2)*	**654**	662
Risk management liabilities *(Notes 6 and 7)*	**51**	78
Non-controlling interests *(Note 4)*	**461**	478
Shareholders' equity		
Common shares *(Notes 13 and 14)*	**2,178**	2,169
Retained earnings *(Note 14)*	**625**	634
Accumulated other comprehensive income *(Note 14)*	**172**	126
Total shareholders' equity	**2,975**	2,929
Total liabilities and shareholders' equity	**9,964**	9,775

Contingencies *(Notes 17 and 19)*
Commitments *(Notes 6 and 18)*
Subsequent events *(Note 24)*

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of Canadian dollars)

Unaudited	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Net earnings (loss)	**51**	(6)	**118**	36
Other comprehensive income (loss)				
Gains (losses) on translating net assets of self-sustaining foreign operations	**42**	(124)	**(8)**	(62)
(Losses) gains on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1)	**(34)**	74	**2**	31
Gains on derivatives designated as cash flow hedges, net of tax(2)	**1**	25	**117**	214
Reclassification of derivatives designated as cash flow hedges to balance sheet, net of tax(3)	**(10)**	(5)	**7**	(8)
Reclassification of derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(45)**	(33)	**(72)**	(57)
Other comprehensive (loss) income	**(46)**	(63)	**46**	118
Comprehensive income (loss)	**5**	(69)	**164**	154

(1) Net of income tax recovery of 5 and nil for the three and six months ended June 30, 2010 (2009 - 16 expense and 9 expense), respectively.

(2) Net of income tax expense of 1 and 60 for the three and six months ended June 30, 2010 (2009 - 6 expense and 98 expense), respectively.

(3) Net of income tax recovery of 4 and expense of 2 for the three and six months ended June 30, 2010 (2009 - 2 recovery and 3 recovery), respectively.

(4) Net of income tax recovery of 23 and 35 for the three and six months ended June 30, 2010 (2009 - 17 recovery and 31 recovery), respectively.

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

Unaudited	3 months ended June 30 **2010**	3 months ended June 30 2009	6 months ended June 30 **2010**	6 months ended June 30 2009
Operating activities				
Net earnings (loss)	**51**	(6)	**118**	36
Depreciation and amortization *(Note 21)*	**122**	122	**232**	243
Gain on sale of equipment	**(1)**	-	**(1)**	-
Non-controlling interests *(Note 4)*	**7**	10	**12**	24
Asset retirement obligation accretion *(Note 12)*	**5**	6	**10**	12
Asset retirement costs settled *(Note 12)*	**(10)**	(8)	**(15)**	(16)
Future income taxes (recovery)	**6**	(23)	**17**	(4)
Unrealized foreign exchange loss (gain)	**1**	(8)	**(2)**	(11)
Unrealized loss from risk management activities	**3**	-	**-**	-
Other non-cash items	**-**	1	**3**	1
	184	94	**374**	285
Change in non-cash operating working capital balances *(Note 22)*	**(86)**	(37)	**(102)**	(145)
Cash flow from operating activities	**98**	57	**272**	140
Investing activities				
Additions to property, plant, and equipment	**(283)**	(281)	**(409)**	(412)
Proceeds on sale of property, plant, and equipment	**1**	-	**3**	1
Proceeds on sale of minority interest in Kent Hills *(Note 3)*	**-**	29	**-**	29
Restricted cash	**-**	(1)	**-**	(2)
Realized losses on financial instruments	**(14)**	(8)	**(21)**	(14)
Net (decrease) increase in collateral received from counterparties	**(54)**	(72)	**26**	120
Net decrease (increase) in collateral paid to counterparties	**4**	(2)	**(2)**	7
Settlement of adjustments on sale of Mexican equity investment *(Note 3)*	**-**	-	**-**	(7)
Other	**2**	(20)	**6**	(14)
Cash flow used in investing activities	**(344)**	(355)	**(397)**	(292)
Financing activities				
Net increase (decrease) in credit facilities	**298**	194	**(29)**	118
Repayment of long-term debt	**(16)**	(16)	**(18)**	(18)
Issuance of long-term debt *(Note 11)*	**-**	200	**301**	200
Dividends paid on common shares	**(64)**	(57)	**(123)**	(111)
Net proceeds on issuance of common shares *(Note 13)*	**3**	-	**4**	-
Realized losses on financial instruments	**-**	-	**(17)**	-
Distributions paid to subsidiaries' non-controlling interests	**(15)**	(17)	**(29)**	(33)
Other	**1**	-	**-**	-
Cash flow from financing activities	**207**	304	**89**	156
Cash flow (used in) from operating, investing, and financing activities	**(39)**	6	**(36)**	4
Effect of translation on foreign currency cash	**(2)**	(1)	**(3)**	-
(Decrease) increase in cash and cash equivalents	**(41)**	5	**(39)**	4
Cash and cash equivalents, beginning of period	**84**	49	**82**	50
Cash and cash equivalents, end of period	**43**	54	**43**	54
Cash taxes paid	**12**	9	**19**	32
Cash interest paid	**37**	51	**54**	66

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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

1. ACCOUNTING POLICIES

These unaudited interim consolidated financial statements do not include all of the disclosures included in TransAlta Corporation's ("TransAlta" or "the Corporation") annual consolidated financial statements. Accordingly, these unaudited interim consolidated financial statements should be read in conjunction with the Corporation's most recent annual consolidated financial statements.

These unaudited interim 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 the 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 consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") using the same accounting policies as those used in the Corporation's most recent annual consolidated financial statements, except as explained below.

2. ACCOUNTING CHANGES

Current Accounting Changes

Inventory

During the second quarter, the Corporation modified its inventory measurement policy for commodity inventories held in its Energy Trading business segment to better reflect the nature of the underlying inventory and the segment's business objectives. Commodity inventories held in the Energy Trading segment are now measured at fair value less costs to sell, as opposed to the lower of cost and net realizable value. Changes in fair value less costs to sell are recognized in net earnings in the period of change. The effect of this change on current and prior periods was not material. Accordingly, the change has been applied prospectively and prior periods have not been restated.

Change in Estimate - Useful Lives

Management conducted a comprehensive review of the estimated useful lives of all generating facilities and coal mining assets, having regard for, among other things, TransAlta's economic lifecycle maintenance program, the existing condition of the assets, progress on carbon capture and other technologies, as well as other market related factors.

Management concluded its review of the coal fleet, as well as its mining assets, and updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, depreciation was reduced by $7 million and $12 million for the three and six months ended June 30, 2010, respectively, compared to the same period in 2009. The estimated annual pre-tax impact of this change is $29 million and will be reflected in depreciation expense and cost of goods sold.

Management continues to perform the comprehensive review on other assets. Any other adjustments resulting from this review will be reflected in future periods.

Future Accounting Changes

International Financial Reporting Standards ("IFRS") Convergence

In 2005, the Accounting Standards Board of Canada ("AcSB") announced that accounting standards in Canada are to converge with IFRS. On May 8, 2009, the AcSB re-confirmed that IFRS will be required for interim and annual financial statements commencing on Jan. 1, 2011, with appropriate comparative IFRS financial information for 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences in accounting policies that will be addressed as part of the convergence project, which have been more fully described in Note 2(D) to the Corporation's annual financial statements. During the second quarter of 2010, no new significant differences were identified.

The project is on track and is currently in the implementation phase with respect to dual reporting in 2010 and in the solution development and implementation phase with respect to 2011 full convergence. Cross-functional, issue-specific teams have been established to analyze the impacts of adopting IFRS, and focus on developing and implementing specific solutions for convergence.

A steering committee, comprised of senior representatives across the Corporation, has been established to monitor the progress and critical decisions in the transition to IFRS, and continues to meet regularly. Quarterly updates are provided to the Audit and Risk Committee. The Corporation is continuing to assess the impact of adopting these standards on the 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 or retained earnings.

3. OTHER INCOME

During the second quarter of 2009, the Corporation sold a 17 per cent interest in its Kent Hills project to Natural Forces Technologies Inc. ("Natural Forces") for proceeds of $29 million, and recorded a pre-tax gain of $1 million. During the first quarter of 2009, the Corporation settled an outstanding commercial issue related to the sale of its Mexican equity investment for a pre-tax gain of $7 million.

4. NON-CONTROLLING INTERESTS

The change in non-controlling interests is provided below:

Balance, Dec. 31, 2009	478
Distributions paid	(29)
Non-controlling interests portion of net earnings	12
Balance, June 30, 2010	**461**

5. INCOME TAX (RECOVERY) EXPENSE

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

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Current tax (recovery) expense	**(42)**	3	**(36)**	(12)
Future income tax expense (recovery)	**6**	(23)	**17**	(4)
Income tax recovery	**(36)**	(20)	**(19)**	(16)

During the quarter, TransAlta recognized a $30 million income tax recovery related to the resolution of certain outstanding tax matters. Interest expense also decreased by $14 million as a result of associated interest recoveries *(Note 11)*. Cash from the resolution of these tax matters is expected to be received before the end of the year.

6. 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. The "Financial Instruments and Hedges" section of Note 1(F) in the Corporation's 2009 annual consolidated financial statements describes how financial instruments are measured and how income and expenses, including fair value gains and losses, are recognized. The following table highlights the carrying amounts and classifications of the financial assets and liabilities:

Carrying value of financial instruments as at June 30, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	43	-	43
Accounts receivable	-	-	372	-	372
Collateral paid	-	-	28	-	28
Risk management assets					
Current	190	23	-	-	213
Long-term	261	4	-	-	265
Financial liabilities			.		
Accounts payable and accrued liabilities	-	-	-	443	443
Collateral received	-	-	-	112	112
Risk management liabilities					
Current	16	18	-	-	34
Long-term	42	9	-	-	51
Long-term debt - recourse(1)	-	-	-	4,171	4,171
Long-term debt - non-recourse(1)	-	-	-	566	566

Carrying value of financial instruments as at Dec. 31, 2009

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	82	-	82
Accounts receivable	-	-	421	-	421
Collateral paid	-	-	27	-	27
Risk management assets					
Current	130	14	-	-	144
Long-term	219	5	-	-	224
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	521	521
Collateral received	-	-	-	86	86
Risk management liabilities					
Current	28	17	-	-	45
Long-term	75	3	-	-	78
Long-term debt - recourse(1)	-	-	-	3,864	3,864
Long-term debt - non-recourse(1)	-	-	-	578	578

(1) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between knowledgeable and willing parties who are under no compulsion to act. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. In limited circumstances, the Corporation uses inputs that are not based on observable market data.

I. Level Determinations and Classifications

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I Energy Trading[1] fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

Level II

Fair values are determined using inputs other than unadjusted quoted prices that are observable for the asset or liability, either directly or indirectly.

Energy Trading fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability, such as basis and location differentials. The Corporation includes over-the-counter derivatives with values based upon observable commodity futures curves and derivatives with input validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

In determining Level II fair values of other risk management assets and liabilities, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

Level III

Fair values are determined using inputs for the asset or liability that are not readily observable.

In limited circumstances, Energy Trading may enter into commodity transactions involving non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are

(1) The Energy Trading segment was referred to as "Commercial Operations and Development" in 2009.

based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. Where commodity transactions extend into periods for which market-observable prices are not available, an internally-developed fundamental price forecast is used in the valuation.

As a result of the acquisition of Canadian Hydro Developers, Inc., TransAlta also has 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 is 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 a specified price with creditworthy counterparties.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value.

Energy Trading

The following table summarizes the key factors impacting the fair value of the Energy Trading risk management assets and liabilities by classification level during the six months ended June 30, 2010:

	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, 2009	-	297	(27)	-	-	1	-	297	(26)
Changes attributable to:									
Market price changes on existing contracts	-	123	11	-	(1)	(1)	-	122	10
Market price changes on new contracts	-	20	-	2	(2)	1	2	18	1
Contracts settled	-	(80)	(3)	-	1	-	-	(79)	(3)
Change in foreign exchange rates	-	-	-	-	-	-	-	-	-
Transfers in/out of Level III	-	-	-	-	-	-	-	-	-
Net risk management assets (liabilities) at June 30, 2010	-	**360**	**(19)**	**2**	**(2)**	**1**	**2**	**358**	**(18)**
Additional Level III gain information:									
Change in fair value included in OCI			8			-			8
Realized gain included in earnings before income taxes			3			-			3
Unrealized gain (loss) included in earnings before income taxes relating to those net assets held at June 30, 2010			-			-			-

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III Energy Trading fair values are determined at June 30, 2010 is estimated to be +/- $18 million (Dec. 31, 2009 – $24 million). Where an internally-developed fundamental price forecast is used, reasonably alternate fundamental price forecasts sourced from external consultants are included in the estimate. In limited circumstances, certain contracts have terms extending beyond five years that require valuations to be extrapolated as the lengths of these contracts make reasonably alternate fundamental price forecasts unavailable.

The total change in Level III financial assets and liabilities held at June 30, 2010, that was recognized in pre-tax earnings for the six months ended June 30, 2010 was nil (June 30, 2009 - nil).

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	68	159	111	22	-	-	**360**
	Level III	-	3	-	-	-	(22)	**(19)**
Non-hedges	Level I	2	-	-	-	-	-	**2**
	Level II	(1)	(3)	-	2	-	-	**(2)**
	Level III	1	-	-	-	-	-	**1**
Total by level	Level I	2	-	-	-	-	-	**2**
	Level II	67	156	111	24	-	-	**358**
	Level III	1	3	-	-	-	(22)	**(18)**
Total net assets (liabilities)		**70**	**159**	**111**	**24**	**-**	**(22)**	**342**

Other Risk Management Assets and Liabilities

The following table summarizes the key factors impacting the fair value of the other risk management assets and liabilities by classification level during the six months ended June 30, 2010:

	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, 2009	-	(24)	-	-	(2)	-	-	(26)	-
Changes attributable to:									
Market price changes on existing contracts	-	24	-	-	(1)	-	-	23	-
Market price changes on new contracts	-	31	-	-	-	-	-	31	-
Contracts settled	-	21	-	-	2	-	-	23	-
Net risk management assets (liabilities) at June 30, 2010	**-**	**52**	**-**	**-**	**(1)**	**-**	**-**	**51**	**-**

Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship. For hedges that remain effective and qualify for hedge accounting, any change in value will be deferred in Accumulated Other Comprehensive Income (“AOCI”) until the instrument is settled or there is a reduction in the net investment in the foreign operations.

The anticipated settlement of the above contracts over each of the next five calendar years and thereafter is as follows:

		2010	2011	2012	2013	2014	2015 and thereafter	Total
Hedges	Level I	-	-	-	-	-	-	**-**
	Level II	-	4	7	10	-	31	**52**
	Level III	-	-	-	-	-	-	**-**
Non-hedges	Level I	-	-	-	-	-	-	**-**
	Level II	(1)	-	-	-	-	-	**(1)**
	Level III	-	-	-	-	-	-	**-**
Total by level	Level I	-	-	-	-	-	-	**-**
	Level II	(1)	4	7	10	-	31	**51**
	Level III	-	-	-	-	-	-	**-**
Total net (liabilities) assets		**(1)**	**4**	**7**	**10**	**-**	**31**	**51**

The fair value of the Corporation's long-term debt is outlined below:

	Fair value(1)				Total carrying value
As at June 30, 2010	**Level I**	**Level II**	**Level III**	**Total**	**value**
Financial assets and liabilities measured at other than fair value					
Long-term debt - June 30, 2010(2)	-	4,934	-	4,934	4,737
Long-term debt - Dec. 31, 2009(2)	-	4,499	-	4,499	4,442

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, collateral paid, accounts payable and accrued liabilities, and collateral received).

(2) Includes current portion.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives have been determined using valuation techniques or models.

In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Balance Sheets in Risk management assets or liabilities, and is recognized in net earnings over the term of the related contract. The difference between the transaction price and the valuation model yet to be recognized in net earnings and a reconciliation of changes during the period is as follows:

As at	**June 30, 2010**	Dec. 31, 2009
Unamortized (loss) gain at beginning of period	**(1)**	2
New transactions	**2**	(1)
Amortization recorded in net earnings during the period	**(1)**	(2)
Unamortized loss at end of period	**-**	(1)

7. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	June 30, 2010					Dec. 31, 2009
	Net Investment Hedges	Cash Flow Hedges	Fair Value Hedges	Not Designated as a Hedge	Total	Total
Risk management assets						
Energy Trading						
Current	-	181	-	22	203	144
Long-term	-	211	-	4	215	207
Total Energy Trading risk management assets	-	392	-	26	418	351
Other						
Current	5	-	4	1	10	-
Long-term	-	14	36	-	50	17
Total other risk management assets	5	14	40	1	60	17
Risk management liabilities						
Energy Trading						
Current	-	11	-	16	27	30
Long-term	-	40	-	9	49	50
Total Energy Trading risk management liabilities	-	51	-	25	76	80
Other						
Current	5	-	-	2	7	15
Long-term	-	2	-	-	2	28
Total other risk management liabilities	5	2	-	2	9	43
Net Energy Trading risk management assets	**-**	**341**	**-**	**1**	**342**	271
Net other risk management assets (liabilities)	**-**	**12**	**40**	**(1)**	**51**	(26)
Net total risk management assets	**-**	**353**	**40**	**-**	**393**	245

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

I. Hedges

a. Net Investment Hedges

i. Hedges of Foreign Operations

U.S. dollar denominated long-term debt with a face value of U.S.$820 million (Dec. 31, 2009 – U.S.$1,100 million), and a U.S. dollar denominated credit facility with a face value of U.S.$300 million (Dec. 31, 2009 – U.S.$300 million) have been designated as a part of the hedge of TransAlta's net investment in self-sustaining foreign operations.

The Corporation has also hedged a portion of its net investment in self-sustaining foreign operations with cross-currency interest rate swaps and foreign currency forward sales (purchase) contracts as shown below:

Cross-Currency Swap

Outstanding liability resulting from cross-currency swap used as part of the net investment hedge is as follows:

June 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
-	**-**	**-**	AUD34	(2)	2010

Foreign Currency Contracts

Outstanding foreign currency forward sale (purchase) contracts used as part of the net investment hedge are as follows:

June 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD167	**-**	**2010**	AUD120	(2)	2010
U.S.77	**-**	**2010**	U.S.(182)	(1)	2010

ii. Effect on the Consolidated Statements of Comprehensive Income (Loss)

For the three months ended June 30, 2010, a net after-tax gain of $8 million (June 30, 2009 – loss of $50 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in Other Comprehensive Income ("OCI"). For the six months ended June 30, 2010, a net after-tax loss of $6 million (June 30, 2009 – loss of $31 million), relating to the translation of the Corporation's net investment in self-sustaining foreign operations, net of hedging, was recognized in OCI.

All net investment hedges currently have no ineffective portion. The following table summarizes the pre-tax impact of net investment hedges on the Consolidated Statements of Comprehensive Income (Loss) for the three and six months ended June 30, 2010 and 2009:

Financial instruments in net investment hedging relationships	**Pre-tax (loss) gain recognized in OCI for the 3 months ended June 30, 2010**	Pre-tax (loss) gain recognized in OCI for the 3 months ended June 30, 2009
Long-term debt	**(39)**	(41)
Cross currency	**3**	(3)
Foreign exchange	**(3)**	134
OCI impact	**(39)**	90

Financial instruments in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI for the 6 months ended June 30, 2010**	Pre-tax gain (loss) recognized in OCI for the 6 months ended June 30, 2009
Long-term debt	**9**	84
Cross currency	**3**	(3)
Foreign exchange	**(10)**	(41)
OCI impact	**2**	40

b. Cash flow hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at June 30, 2010, were as follows:

(Thousands)	June 30, 2010		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	31,435	12	28,987	-
Natural gas (GJ)	1,213	1,740	2,163	360
Oil (gallons)	-	20,790	-	25,074

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Receipts and Expenditures

The Corporation uses forward foreign exchange contracts to hedge a portion of its future foreign denominated receipts and expenditures as follows:

June 30, 2010				Dec. 31, 2009			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
20	U.S.19	-	2010	91	U.S.78	(8)	2010
U.S.7	7	-	2010	U.S.14	15	-	2010
-	-	-	-	AUD4	U.S.3	-	2010

Foreign Exchange Forward Contracts on Foreign Denominated Debt

Outstanding foreign exchange forward purchase contracts used to manage foreign exchange exposure on debt not designated as a net investment hedge are as follows:

June 30, 2010			Dec. 31, 2009		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset	Maturity
U.S.300	6	2012	-	-	-
U.S.300	7	2013	-	-	-

Cross-Currency Swap

TransAlta uses cross-currency swaps to manage foreign exchange risk exposures on foreign denominated debt as follows:

June 30, 2010			Dec. 31, 2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
U.S.500	(1)	2015	U.S.500	(16)	2015

iii. Interest Rate Risk Management

The Corporation also had outstanding forward start interest rate swaps that converted floating rate debt into fixed rate debt with fixed rates ranging from 3.5 per cent to 4.6 per cent. These swaps were closed out upon the issuance of the U.S. $300 million senior notes during the first quarter and the resulting losses have been included in AOCI and will be recognized over the term of the senior notes.

June 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
-	-	-	U.S.300	(8)	2020

iv. Effect on the Consolidated Statements of Comprehensive Income (Loss)

Forward sale and purchase commodity contracts, foreign exchange contracts, as well as interest rate contracts, are used to hedge the variability in future cash flows. All components of each derivative's change in fair value have been included in the assessment of cash flow hedge effectiveness.

The following tables summarize the impact of cash flow hedges on the Consolidated Statements of Comprehensive Income (Loss), Consolidated Statements of Earnings (Loss), and the Consolidated Balance Sheets for the three and six months ended June 30, 2010 and 2009:

3 months ended June 30, 2010

Effective portion				**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax (loss) gain recognized in OCI**	**Location of loss reclassified from OCI**	**Pre-tax loss reclassified from OCI**	**Location of loss recognized in earnings**	**Pre-tax loss recognized in earnings**
Commodity	**(41)**	Revenue	**(49)**	Revenue	**-**
Foreign exchange gain (loss) on project hedges	**8**	Property, plant, and equipment	**(14)**	Interest expense	**(1)**
Foreign exchange gain (loss) on U.S. debt	**24**	Foreign exchange gain (loss) on U.S. debt	**(19)**		
Cross-currency swaps	**(7)**	Interest expense	**-**		
Interest rate	**18**				
OCI impact	**2**	**OCI impact**	**(82)**	**Net earnings impact**	**(1)**

3 months ended June 30, 2009

Effective portion				Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of loss reclassified from OCI	Pre-tax loss reclassified from OCI	Location of loss recognized in earnings	Pre-tax loss recognized in earnings
Commodity	56	Revenue	(50)	Revenue	(2)
Foreign exchange gain (loss) on project hedges	9	Property, plant, and equipment	(7)	Interest expense	(1)
Cross-currency swaps	-	Interest expense	-		
Interest rate	(34)				
OCI impact	31	OCI impact	(57)	Net earnings impact	(3)

6 months ended June 30, 2010					
Effective portion				**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (loss) gain reclassified from OCI**	**Pre-tax (loss) gain reclassified from OCI**	**Location of loss recognized in earnings**	**Pre-tax loss recognized in earnings**
Commodity	**160**	Revenue	**(88)**	Revenue	**-**
Foreign exchange gain (loss) on project hedges	**1**	Property, plant, and equipment	**9**	Interest expense	**(1)**
Foreign exchange gain (loss) on U.S. debt	**24**	Foreign exchange gain (loss) on U.S. debt	**(19)**		
Cross-currency swaps	**(17)**	Interest expense	**-**		
Interest rate	**9**				
OCI impact	**177**	**OCI impact**	**(98)**	**Net earnings impact**	**(1)**

6 months ended June 30, 2009					
Effective portion				Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of loss reclassified from OCI	Pre-tax loss reclassified from OCI	Location of loss recognized in earnings	Pre-tax loss recognized in earnings
Commodity	336	Revenue	(88)	Revenue	(2)
Foreign exchange gain (loss) on project hedges	10	Property, plant, and equipment	(11)	Interest expense	(1)
Cross-currency swaps	-	Interest expense	-		
Interest rate	(34)				
OCI impact	312	OCI impact	(99)	Net earnings impact	(3)

Over the next 12 months, the Corporation estimates that $112 million (Dec. 31, 2009 – $77 million after-tax gains) of after-tax gains will be reclassified from AOCI and recognized in net earnings.

c. Fair value hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt, with rates ranging from 5.75 per cent to 6.9 per cent, to floating rate debt through interest rate swaps as shown below:

June 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity
100	**4**	**2011**	100	7	2011
U.S.100	**3**	**2013**	U.S.50	(1)	2013
U.S.400	**33**	**2018**	U.S.150	7	2018

Including the interest rate swaps above, 35 per cent of the Corporation's debt is subject to floating interest rates (Dec. 31, 2009 – 31 per cent).

ii. Effect on the Consolidated Statements of Comprehensive Income (Loss)

No ineffective portion of fair value hedges was recorded for the three and six months ended June 30, 2010 and 2009.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings (Loss) for the three and six months ended June 30, 2010 and 2009:

Derivatives in fair value hedging relationships	Location of gain (loss) on statements of earnings	3 months ended June 30		6 months ended June 30	
		2010	2009	**2010**	2009
Interest rate contracts	Interest expense	**25**	12	**27**	15
Long-term debt	Interest expense	**(25)**	(12)	**(27)**	(15)
Net earnings impact		**-**	-	-	-

II. Non-Hedges

The Corporation enters into a variety of commodity derivative transactions, including certain commodity hedging transactions that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting where 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 as revenue in the period the change occurs.

a. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments that are not designated as hedging instruments at June 30, 2010, were as follows:

(Thousands)	June 30, 2010		Dec. 31, 2009	
Type	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**19,221**	**19,742**	14,107	14,844
Natural gas (GJ)	**530,977**	**532,692**	323,793	309,764
Transmission (MWh)	**-**	**3,100**	-	4,852

b. Cross-Currency Swaps

Cross-currency swaps are periodically entered into in order to limit the Corporation's exposure to fluctuations in foreign exchange and interest rates. The liability resulting from an outstanding cross-currency swap is as follows:

June 30, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
-	**-**	**-**	AUD13	(2)	2010

c. Foreign Currency Contracts

The Corporation periodically enters into foreign exchange forwards to hedge future foreign denominated revenues and expenses for which hedge accounting is not pursued. These items are classified as held for trading, and changes in the fair values associated with these transactions are recognized in net earnings.

Outstanding notional amounts and fair values associated with these forward contracts are as follows:

June 30, 2010				Dec. 31, 2009			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
AUD14	**13**	**-**	**2010**	-	-	-	-
AUD8	**U.S.6**	**-**	**2010**	-	-	-	-
U.S.56	**58**	**(1)**	**2010**	U.S.13	14	-	2010

d. 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 chosen. 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.

e. Effect on the Consolidated Statements of Comprehensive Income (Loss)

The tables below summarizes the net realized and unrealized gains and losses included in net earnings that are associated with derivatives not designated as hedges:

	3 months ended June 30					
	2010			2009		
	Net unrealized (losses) gains	**Net realized (losses) gains**	**Total**	Net unrealized (losses) gains	Net realized gains	Total
Commodity	**(5)**	**(4)**	**(9)**	(1)	23	22
Interest	**-**	**-**	**-**	(1)	-	(1)
Foreign exchange	**3**	**-**	**3**	3	1	4
Other	**-**	**2**	**2**	-	2	2

	6 months ended June 30					
	2010			2009		
	Net unrealized gains	**Net realized gains**	**Total**	Net unrealized gains	Net realized gains (losses)	Total
Commodity	**-**	**6**	**6**	-	33	33
Interest	**-**	**-**	**-**	-	(1)	(1)
Foreign exchange	**4**	**1**	**5**	4	(5)	(1)
Other	**-**	**2**	**2**	-	(1)	(1)

B. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk – Proprietary Energy Trading

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. Value at Risk ("VaR") at June 30, 2010 associated with the Corporation's proprietary energy trading activities was $4 million (Dec. 31, 2009 – $3 million).

b. Commodity Price Risk - Generation

VaR at June 30, 2010 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $44 million (Dec. 31, 2009 – $45 million).

The Corporation's policy on asset-backed transactions is to seek normal purchase / normal sale ("NPNS") contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or short-term optimization transactions, such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at June 30, 2010 associated with the Corporation's commodity derivative instruments used in the generation segment, but which are not designated as hedges, was nil (Dec. 31, 2009 – nil).

c. Interest Rate Risk

The possible effect on net earnings and OCI, due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, and held for trading and hedging interest rate derivatives outstanding at the balance sheet date, 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.

	6 months ended June 30			
	2010		2009	
	Net earnings increase(1)	**OCI loss(1)**	Net earnings increase(1)	OCI loss(1)
50 basis point change	3	-	2	(5)

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

d. Currency Rate Risk

The foreign currency risk sensitivities outlined below are limited to the risks that arise on financial instruments denominated in currencies other than the functional currency.

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments outstanding at the balance sheet date, is outlined below. The sensitivity analysis has been prepared using management's assessment that a five cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

	6 months ended June 30			
	2010		2009	
Currency	**Net earnings decrease(1)**	**OCI gain(1,2)**	Net earnings decrease(1)	OCI gain(1,2)
Euro	-	-	-	1
U.S.	(5)	1	(2)	4
AUD	(1)	-	(2)	-
Total	**(6)**	**1**	(4)	5

(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 used as the hedging instruments in the net investment hedges have been excluded.

II. Credit Risk

At June 30, 2010, TransAlta had one counterparty whose net settlement position accounted for greater than 10 per cent of the total trade receivables outstanding at the end of the period.

The Corporation's maximum exposure to credit risk at June 30, 2010 and at Dec. 31, 2009, without taking into account collateral held, is represented by the current carrying amounts of accounts receivable and risk management assets as per the Consolidated Balance Sheets. 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 customer for commodity trading operations and hedging, excluding the California market receivables and including the fair value of open trading, net of any collateral held, at June 30, 2010 was $56 million (Dec. 31, 2009 – $63 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 counterparties. The following table outlines the distribution, by credit rating, of financial assets as at June 30, 2010:

	Investment grade %	Non-investment grade %	Total %
Accounts receivable	91	9	100
Risk management assets	100	-	100

The Corporation utilizes an allowance for doubtful accounts to record potential credit losses associated with trade receivables. A reconciliation of the account for the period is presented below:

As at	June 30, 2010	Dec. 31, 2009
Allowance at beginning of period	**49**	57
Change in foreign exchange rates	**-**	(8)
Allowance at end of period	**49**	49

At June 30, 2010, the Corporation did not have any significant past due trade receivables except as disclosed in Note 19.

III. Liquidity Risk

A maturity analysis for the Corporation's financial assets and liabilities is as follows:

	2010	2011	2012	2013	2014	2015 and thereafter	Total
Accounts payable and accrued liabilities	443	-	-	-	-	-	443
Collateral received	112	-	-	-	-	-	112
Debt(1)	14	254	1,064	661	232	2,523	4,748
Energy Trading risk management (assets) liabilities(2)	(70)	(159)	(111)	(24)	-	22	(342)
Other risk management liabilities (assets)(2)	1	(4)	(7)	(10)	-	(31)	(51)
Interest on long-term debt	130	266	240	216	183	1,158	2,193
Total	**630**	**357**	**1,186**	**843**	**415**	**3,672**	**7,103**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2012 and 2013.

(2) Net risk management assets and liabilities as above.

C. Collateral

I. Financial Instruments Provided as Collateral

At June 30, 2010, $32 million (Dec. 31, 2009 – $45 million) of financial assets, consisting of cash and accounts receivable, related to the Corporation's proportionate share of CE Generation, LLC ("CE Gen") have been pledged as collateral for certain CE Gen debt. Should any defaults occur the debt-holders would have first claim on these assets.

At June 30, 2010, the Corporation provided $28 million (Dec. 31, 2009 – $27 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At June 30, 2010, the Corporation received $112 million (Dec. 31, 2009 – $86 million) in cash collateral associated with counterparty obligations. Under the terms of the contract, the Corporation may be obligated to pay interest on the outstanding balance and to return the principal when the counterparty has met its contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

III. Contingent Features in Derivative Instruments

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

As at June 30, 2010 the Corporation had posted collateral of $17 million (Dec. 31, 2009 - $37 million) in the form of letters of credit, on derivative instruments in a net liability position. If the credit-risk-contingent features included in certain derivative agreements were triggered, based upon the value of derivatives as at June 30, 2010, the Corporation would be required to post an additional $31 million of collateral to its counterparties.

8. INVENTORY

Inventory held in the normal course of business which includes coal, emission credits, and natural gas are valued at the lower of cost and net realizable value. Inventory held for commodity trading, which also includes natural gas, is valued at fair value less costs to sell *(Note 2)*. The classifications are as follows:

As at	**June 30, 2010**	Dec. 31, 2009
Coal	**98**	86
Natural gas	**5**	4
Total	**103**	90

The increase in coal inventory at June 30, 2010 compared to Dec. 31, 2009 is primarily due to lower production at the Centralia Thermal plant and the Sundance facility.

The change in inventory is outlined below:

Balance, Dec. 31, 2009	90
Net additions	13
Balance, June 30, 2010	**103**

No inventory is pledged as security for liabilities.

For the three and six months ended June 30, 2010, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

9. LONG-TERM RECEIVABLE

In 2008, the Corporation was reassessed by taxation authorities in Canada related 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 and subsequent to the quarter end, a decision from Tax Court was received which allowed for the recovery of $38 million of the previously paid taxes and interest. TransAlta is reviewing the decision to determine if the Corporation will appeal the court ruling.

10. OTHER ASSETS

The components of other assets are as follows:

As at	**June 30, 2010**	Dec. 31, 2009
Deferred license fees	**21**	22
Accrued pension benefit asset	**21**	18
Project development costs	**49**	45
Keephills 3 transmission deposit	**8**	8
Other	**8**	9
Total other assets	**107**	102

11. LONG-TERM DEBT AND NET INTEREST EXPENSE

The amounts outstanding are as follows:

As at	June 30, 2010			Dec. 31, 2009		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**1,033**	**1,033**	**1.0%**	1,063	1,063	1.0%
Debentures, due 2011 to 2030	**1,057**	**1,076**	**6.7%**	1,055	1,076	6.7%
Senior notes(3)	**2,025**	**2,001**	**6.0%**	1,687	1,684	5.9%
Non-recourse	**566**	**582**	**6.5%**	578	581	6.3%
Other	**56**	**56**	**6.7%**	59	59	6.7%
	4,737	**4,748**		4,442	4,463	
Less: current portion	**254**	**254**		31	31	
Total long-term debt	**4,483**	**4,494**		4,411	4,432	

(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.

(3) 2010 - U.S.$1,900 million, 2009 - $1,600 million.

On March 12, 2010, the Corporation issued senior notes in the amount of U.S.$300 million, bearing interest at a rate of 6.5 per cent and maturing in 2040.

The components of net interest expense are as follows:

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Interest on debt	**61**	43	**118**	86
Interest income *(Note 5)*	**(15)**	(1)	**(15)**	(3)
Capitalized interest	**(13)**	(9)	**(22)**	(17)
Net interest expense	**33**	33	**81**	66

The Corporation capitalizes interest during the construction phase of growth capital projects.

12. ASSET RETIREMENT OBLIGATIONS

The change in the asset retirement obligation balances is summarized below:

Balance, Dec. 31, 2009	282
Liabilities incurred in period	1
Liabilities settled in period	(15)
Accretion expense	10
Revisions in estimated cash flows	(22)
Change in foreign exchange rates	-
	256
Less: current portion	37
Balance, June 30, 2010	**219**

Revisions in estimated cash flows are primarily due to changes in the estimates associated with the decommissioning of the Wabamun plant, which was shut down on March 31, 2010.

13. COMMON SHARES ISSUED AND OUTSTANDING

A. Issued and outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value. At June 30, 2010, the Corporation had 218.8 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended June 30, 2010, 0.2 million (June 30, 2009 – nil) common shares were issued for proceeds of $3 million (June 30, 2009 – nil). During the six months ended June 30, 2010, 0.4 million (June 30, 2009 – 0.2 million) common shares were issued for proceeds of $4 million (June 30, 2009 – nil).

During the three and six months ended June 30, 2010 and 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid ("NCIB") program prior its expiry on May 6, 2010.

B. Stock options

At June 30, 2010, the Corporation had 2.3 million outstanding employee stock options (Dec. 31, 2009 – 1.5 million), reflecting 0.9 million stock options granted on Feb. 1, 2010, at a strike price of $22.46, being the last sale price of board lots of the shares on the Toronto Stock Exchange the day prior to the day the options were granted for Canadian employees, and U.S.$20.75, being the closing sale price on the New York Stock Exchange on the same date for U.S. employees. These options will vest in equal installments over four years starting Feb. 1, 2011 and expire after 10 years. During the three months ended June 30, 2010, a nominal number of options also expired, or were exercised or cancelled (June 30, 2009 – 0.1 million cancelled). During the six months ended June 30, 2010, a nominal number of options also expired, or were exercised or cancelled (June 30, 2009 – 0.1 million expired, 0.1 million cancelled).

The estimated fair value of these options granted was determined using the Black-Scholes option-pricing model and the following assumptions, resulting in a fair value of $3.67 per option:

Risk free interest rate (%)	2.5
Expected life of the options (years)	4.9
Expected annual dividend yield (%)	5.1
Volatility in the price of the Corporation's shares (%)	29.7

For the three and six months ended June 30, 2010, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was nil (June 30, 2009 - nil), and $1 million (June 30, 2009 - $1 million), respectively.

C. Dividend Reinvestment and Share Purchase ("DRASP") Plan

Under the terms of the DRASP plan, participants are able to purchase additional common shares by reinvesting dividends or making an additional contribution of up to $5,000 per quarter. On April 29, 2010, in accordance with the terms of the DRASP plan, the Board of Directors approved the issuance of shares from Treasury at a three per cent discount from the weighted average price of the shares traded on the Toronto Stock Exchange on the last five days preceding the dividend payment date. During the quarter, the Corporation issued 0.2 million common shares for proceeds of $3 million. Under the terms of the DRASP plan, the Corporation reserves the right to alter the discount or return to purchasing the shares on the open market at any time.

14. SHAREHOLDERS' EQUITY

A reconciliation of shareholders' equity is as follows:

	Common shares	Retained earnings	Accumulated other comprehensive income	Total shareholders' equity
Balance, Dec. 31, 2009	2,169	634	126	2,929
Net earnings	-	118	-	118
Common shares issued	9	-	-	9
Dividends declared	-	(127)	-	(127)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	-	-	(6)	(6)
Gains on derivatives designated as cash flow hedges, net of tax	-	-	117	117
Derivatives designated as cash flow hedges in prior periods transferred to the Consolidated Balance Sheets and net earnings in the current period, net of tax	-	-	(65)	(65)
Balance, June 30, 2010	**2,178**	**625**	**172**	**2,975**

The components of AOCI are presented below:

As at	June 30, 2010	Dec. 31, 2009
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and of tax	**(69)**	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	**241**	189
Total accumulated other comprehensive income	**172**	126

15. CAPITAL

TransAlta's capital is comprised of the following:

As at	June 30, 2010	Dec. 31, 2009	Increase/ (decrease)
Current portion of long-term debt	**254**	31	223
Less: cash and cash equivalents	**(43)**	(82)	39
	211	(51)	262
Long-term debt			
Recourse	**3,939**	3,857	82
Non-recourse	**544**	554	(10)
Non-controlling interests	**461**	478	(17)
Shareholders' equity			
Common shares	**2,178**	2,169	9
Retained earnings	**625**	634	(9)
AOCI	**172**	126	46
	7,919	7,818	101
Total capital	**8,130**	7,767	363

TransAlta's overall capital management strategy has remained unchanged from Dec. 31, 2009.

TransAlta monitors key credit ratios similar to those used by key rating agencies. While these ratios are not publicly available from credit agencies, TransAlta's management has defined these ratios and seeks to manage the Corporation's capital in line with the following targets:

	June 30, 2010	Dec. 31, 2009	Target
Cash flow to interest coverage (times)(1)	**5.0**	4.9	4 to 5 times
Cash flow to debt (%)(1)	**21.1**	20.1	20 to 25 per cent
Debt to invested capital (%)	**57.7**	56.1	55 to 60 per cent

(1) Last 12 months.

For the three and six months ended June 30, 2010 and 2009, net cash outflows from operating activities, after dividends and capital asset additions, are summarized below:

	3 months ended June 30			**6 months ended June 30**		
	2010	2009	Increase/ (Decrease)	**2010**	2009	Increase/ (Decrease)
Cash flow from operating activities	**98**	57	41	**272**	140	132
Dividends paid	**(64)**	(57)	(7)	**(123)**	(111)	(12)
Capital asset expenditures	**(283)**	(281)	(2)	**(409)**	(412)	3
Net cash outflow	**(249)**	(281)	32	**(260)**	(383)	123

For the three months ended June 30, 2010, the increase in the net cash flows relative to the second quarter of 2009 resulted primarily from higher cash flow from operating activities. For the six months ended June 30, 2010, the increase in the net cash flows relative to the same period in 2009 resulted primarily from higher cash flow from operating activities. TransAlta seeks to maintain sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business.

The financial terms and conditions of the Corporation's credit facilities remain unchanged from Dec. 31, 2009.

TransAlta's formal dividend policy has remained unchanged from Dec. 31, 2009.

16. RELATED PARTY TRANSACTIONS

On Dec.16, 2006, predecessors of TransAlta Generation Partnership ("TAGP"), a firm owned by the Corporation and one of its subsidiaries, entered into an agreement with the partners of the Keephills 3 joint venture project to supply coal for the coal-fired plant. The joint venture project is held in a partnership owned by Keephills 3 Limited Partnership ("K3LP"), a wholly owned subsidiary of the Corporation, and Capital Power Corporation. TAGP will supply coal until the earlier of the permanent closure of the Keephills 3 facility or the early termination of the agreement by TAGP and the partners of the joint venture. As at June 30, 2010, TAGP had received $57 million from K3LP for future coal deliveries. Commercial operation of the Keephills plant is scheduled to commence in the second quarter of 2011. Payments received prior to that date for future coal deliveries are recorded in deferred revenues and will be amortized into revenue over the life of the coal supply agreement when TAGP starts delivering coal for commissioning activities.

For the period November 2002 to November 2012, one of TransAlta's subsidiaries, TransAlta Cogeneration, L.P. ("TA Cogen"), entered into various transportation swap transactions with TAGP. TAGP operates and maintains TA Cogen's three combined-cycle power plants in Ontario and a plant in Fort Saskatchewan, Alberta. TAGP also provides management services to the Sheerness thermal plant, which is operated by Canadian Utilities Limited. The business purpose of these transportation swaps is to provide TA Cogen with the delivery of fixed price gas without being exposed to escalating costs of pipeline transportation for two of its plants over the period of the swap. The notional gas volume in the swap transactions is equal to the total delivered fuel for each of the facilities. Exchange amounts are based on the market value of the contract. TransAlta entered into an offsetting contract and therefore has no risk other than counterparty risk.

17. CONTINGENCIES

TransAlta is occasionally named as a party in various claims and legal proceedings which 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. Although there can be no assurance that any particular claim will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of any claims or potential claims of which it is currently aware, when taken as a whole, will have a material adverse effect on the Corporation.

18. COMMITMENTS

On Jan. 11, 2010, TransAlta announced that it had been awarded a 25-year contract to provide an additional 54 megawatts ("MW") of wind power to New Brunswick Power. Under the agreement, TransAlta will expand the existing 96 MW Kent Hills wind facility to a total of 150 MW. The total capital cost of the project is estimated to be $100 million and is expected to begin commercial operations by the end of 2010. Natural Forces will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

19. PRIOR PERIOD REGULATORY DECISION

With respect to refunds owing by TransAlta for sales made by it in the organized markets of the California Power Exchange and the California Independent System Operator, the California Parties have sought rehearing of the Federal Energy Regulatory Commission's ("FERC") refusal and appealed the refusal to the U.S. Court of Appeals for the Ninth Circuit. In a decision issued Aug. 24, 2007, which denied rehearing remanded matters to FERC, the Ninth Circuit ruled that FERC had properly excluded both the Summer Transactions and the CERS Transactions from the complaint proceeding. FERC has yet to respond to the remand.

20. GUARANTEES – LETTERS OF CREDIT

Letters of credit are issued to counterparties under some contractual arrangements with 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 Balance Sheets. All letters of credit expire within one year and are expected to be renewed, as needed, through the normal course of business. The total outstanding letters of credit as at June 30, 2010 totalled $318 million (Dec. 31, 2009 - $334 million) with nil (Dec. 31, 2009 – nil) amounts exercised by third parties under these arrangements. TransAlta has a total of $2.1 billion (Dec. 31, 2009 – $2.1 billion) of committed credit facilities of which $0.8 billion (Dec. 31, 2009 – $0.7 billion) is not drawn, and is available as of June 30, 2010, subject to customary borrowing conditions.

21. SEGMENTED DISCLOSURES

A. Each business segment assumes responsibility for its operating results measured as operating income or loss.

3 months ended June 30, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**582**	**-**	**-**	**582**
Fuel and purchased power	**229**	**-**	**-**	**229**
	353	**-**	**-**	**353**
Operations, maintenance, and administration	**150**	**4**	**18**	**172**
Depreciation and amortization	**113**	**1**	**4**	**118**
Taxes, other than income taxes	**8**	**-**	**-**	**8**
Intersegment cost allocation (recovery)	**2**	**(2)**	**-**	**-**
	273	**3**	**22**	**298**
	80	**(3)**	**(22)**	**55**
Net interest expense *(Note 11)*				**(33)**
Earnings before non-controlling interests and income taxes				**22**

3 months ended June 30, 2009	Generation	Energy Trading	Corporate	Total
Revenues	570	15	-	585
Fuel and purchased power	239	-	-	239
	331	15	-	346
Operations, maintenance, and administration	172	10	25	207
Depreciation and amortization	113	-	5	118
Taxes, other than income taxes	7	-	-	7
Intersegment cost allocation (recovery)	8	(8)	-	-
	300	2	30	332
	31	13	(30)	14
Foreign exchange gain				2
Net interest expense *(Note 11)*				(33)
Other income *(Note 3)*				1
Loss before non-controlling interests and income taxes				(16)

6 months ended June 30, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**1,294**	**14**	**-**	**1,308**
Fuel and purchased power	**551**	**-**	**-**	**551**
	743	**14**	**-**	**757**
Operations, maintenance, and administration	**288**	**8**	**36**	**332**
Depreciation and amortization	**212**	**1**	**9**	**222**
Taxes, other than income taxes	**14**	**-**	**-**	**14**
Intersegment cost allocation (recovery)	**3**	**(3)**	**-**	**-**
	517	**6**	**45**	**568**
	226	**8**	**(45)**	**189**
Foreign exchange gain				**3**
Net interest expense *(Note 11)*				**(81)**
Earnings before non-controlling interests and income taxes				**111**

6 months ended June 30, 2009	Generation	Energy Trading	Corporate	Total
Revenues	1,311	30	-	1,341
Fuel and purchased power	614	-	-	614
	697	30	-	727
Operations, maintenance, and administration	318	16	47	381
Depreciation and amortization	224	1	10	235
Taxes, other than income taxes	12	-	-	12
Intersegment cost allocation (recovery)	16	(16)	-	-
	570	1	57	628
	127	29	(57)	99
Foreign exchange gain				3
Net interest expense *(Note 11)*				(66)
Other income *(Note 3)*				8
Earnings before non-controlling interests and income taxes				44

For the three months ended June 30, 2010 and 2009, included above in Generation is $4 million and $2 million of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects, respectively. For the six months ended June 30, 2010 and 2009, incentives of $9 million and $4 million, respectively, were included above in Generation.

The intersegment cost allocation (recovery) decreased for the three and six months ended June 30, 2010 as a result of support costs previously recovered through the intersegment fee being directly recorded in the Generation segment in 2010.

B. Selected Consolidated Balance Sheets information

As at June 30, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Goodwill	**404**	**30**	**-**	**434**
Total segment assets	**9,357**	**106**	**501**	**9,964**

As at Dec. 31, 2009				
Goodwill	404	30	-	434
Total segment assets	9,133	148	494	9,775

C. Selected Consolidated Cash Flow information

3 months ended June 30, 2010	Generation	Energy Trading	Corporate	Total
Capital expenditures	**276**	**-**	**7**	**283**

3 months ended June 30, 2009				
Capital expenditures	275	1	5	281

6 months ended June 30, 2010	Generation	Trading	Corporate	Total
Capital expenditures	**395**	**-**	**14**	**409**

6 months ended June 30, 2009				
Capital expenditures	402	1	9	412

D. Depreciation and amortization on the Consolidated Statements of Cash Flows

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

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**118**	118	**222**	235
Depreciation included in fuel and purchased power	**8**	10	**19**	20
Accretion expense included in depreciation and amortization expense	**(5)**	(6)	**(10)**	(12)
Other	**1**	-	**1**	-
Depreciation and amortization on the Consolidated Statements of Cash Flows	**122**	122	**232**	243

22. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

	3 months ended June 30		6 months ended June 30	
	2010	2009	**2010**	2009
Source (use):				
Accounts receivable	**(46)**	34	**54**	214
Prepaid expenses	**2**	2	**(6)**	(8)
Income taxes receivable	**(61)**	(3)	**(59)**	(39)
Inventory	**(21)**	(34)	**(9)**	(39)
Accounts payable and accrued liabilities	**41**	(28)	**(78)**	(262)
Income taxes payable	**(1)**	(8)	**(4)**	(11)
Change in non-cash operating working capital	**(86)**	(37)	**(102)**	(145)

23. EMPLOYEE FUTURE BENEFITS

Costs recognized in the period are presented below:

3 months ended June 30, 2010	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**1**	**-**	**1**	**2**
Interest cost	**5**	**1**	**-**	**6**
Actual return on plan assets	**(5)**	**-**	**-**	**(5)**
Actuarial loss	**1**	**-**	**-**	**1**
Amortization of net transition asset	**(2)**	**-**	**-**	**(2)**
Defined benefit expense	**-**	**1**	**1**	**2**
Defined contribution option expense of registered pension plan	**4**	**-**	**-**	**4**
Net expense	**4**	**1**	**1**	**6**

3 months ended June 30, 2009	Registered	Supplemental	Other	Total
Current service cost	1	1	-	2
Interest cost	6	1	-	7
Actual return on plan assets	(5)	-	-	(5)
Amortization of net transition asset	(2)	-	-	(2)
Defined benefit expense	-	2	-	2
Defined contribution option expense of registered pension plan	3	-	-	3
Net expense	3	2	-	5

6 months ended June 30, 2010	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**1**	**1**	**1**	**3**
Interest cost	**10**	**2**	**1**	**13**
Actual return on plan assets	**(10)**	**-**	**-**	**(10)**
Actuarial loss	**2**	**-**	**-**	**2**
Amortization of net transition asset	**(4)**	**-**	**-**	**(4)**
Defined benefit (income) expense	**(1)**	**3**	**2**	**4**
Defined contribution option expense of registered pension plan	**10**	**-**	**-**	**10**
Net expense	**9**	**3**	**2**	**14**

6 months ended June 30, 2009	Registered	Supplemental	Other	Total
Current service cost	2	1	-	3
Interest cost	11	2	1	14
Actual return on plan assets	(10)	-	-	(10)
Actuarial loss	1	-	-	1
Amortization of net transition asset	(4)	-	-	(4)
Defined benefit expense	-	3	1	4
Defined contribution option expense of registered pension plan	10	-	-	10
Net expense	10	3	1	14

24. SUBSEQUENT EVENTS

TransAlta has evaluated events subsequent to June 30, 2010 through to July 28, 2010, which represents the date the financial statements were issued, and identified no items warranting disclosure.

SUPPLEMENTAL INFORMATION

		June 30, 2010	Dec. 31, 2009
Closing market price (TSX) ($)		**19.72**	23.48
Price range for the last 12 months (TSX) ($)	High	**23.98**	25.30
	Low	**19.61**	18.11
Debt to invested capital including non recourse debt (%)		**57.7**	56.1
Debt to invested capital excluding non recourse debt (%)		**54.6**	52.6
Return on shareholders' equity (%)		**10.2**	6.9
Comparable return on shareholders' equity(1), (2) (%)		**9.2**	6.9
Return on capital employed(1) (%)		**6.7**	5.7
Comparable return on capital employed(1), (2) (%)		**6.9**	5.8
Cash dividends per share(1) ($)		**1.16**	1.16
Price/earnings ratio(1) (times)		**15.7**	26.1
Earnings coverage(1) (times)		**2.2**	1.9
Dividend payout ratio based on net earnings(1) (%)		**94.3**	129.8
Dividend payout ratio based on comparable earnings(1), (2) (%)		**104.2**	129.8
Dividend coverage(1) (times)		**2.9**	2.5
Dividend yield(1) (%)		**5.9**	4.9
Cash flow to debt(1) (%)		**21.1**	20.1
Cash flow to interest coverage(1) (times)		**5.0**	4.9

(1) Last 12 months

(2) These ratios incorporate items that are not defined under Canadian GAAP. None of these measurements are used to enhance the Corporation's reported financial performance or position. 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-GAAP measure used in this calculation, refer to the Non-GAAP Measures section of this MD&A.

RATIO FORMULAS

Debt to invested capital = (debt – cash and cash equivalents) / (debt + non-controlling interests + shareholders' equity – cash and cash equivalents)

Return on shareholders' equity = net earnings (loss) or earnings (loss) on a comparable basis / average shareholders' equity excluding Accumulated Other Comprehensive Income ("AOCI")

Return on capital employed = [earnings (loss) 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/earnings ratio = current period's close price / basic earnings (loss) per share

Earnings coverage = [net earnings (loss) + income taxes + net interest expense] / (interest on debt – interest income)

Dividend payout ratio = dividends / net earnings (loss) or earnings (loss) on a comparable basis

Dividend coverage = cash flow from operating activities / common share dividends

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

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

Cash flow to interest coverage = (cash flow from operating activities before changes in working capital + net interest expense) / (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.

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.

Carbon Capture and Storage (CCS) - An approach to mitigating the contribution of greenhouse gas emissions to global warming, which is based on capturing carbon dioxide emissions from industrial operations and permanently storing them in deep underground formations.

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.

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

Unplanned Outage - The shutdown 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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