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 months ended March 31, 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 April 26, 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.

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

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

3 months ended March 31	**2010**	2009
Availability (%)	**91.4**	86.4
Production (GWh)	**12,914**	12,173
Revenue	**726**	756
Gross margin(1)	**404**	381
Operating income(1)	**134**	85
Net earnings	**67**	42
Net earnings per share, basic and diluted	**0.31**	0.21
Comparable earnings per share(1)	**0.31**	0.18
Earnings before interest, taxes, depreciation, and amortization ("EBITDA")(1)	**249**	212
Cash flow from operating activities	**174**	83
Cash flow from operating activities per share(1)	**0.79**	0.42
Free cash flow (deficiency)(1)	**56**	(64)
Cash dividends declared per share	**0.29**	0.29

	As at March 31, 2010	As at Dec. 31, 2009
Total assets	**9,707**	9,762
Total long-term financial liabilities	**5,417**	5,512

AVAILABILITY & PRODUCTION

Availability for the three months ended March 31, 2010 increased compared to the same period in 2009 due to lower planned outages at the Keephills and Sundance plants, and lower unplanned outages at the Sundance and Wabamun plants, partially offset by higher unplanned outages at the Centralia Thermal and Sheerness plants.

Production for the three months ended March 31, 2010 increased 741 gigawatt hours (“GWh”) compared to the same period in 2009 due to lower planned outages at the Keephills and Sundance plants, lower unplanned outages at the Sundance and Wabamun plants, and higher wind volumes, partially offset by the expiration of the long-term contract at Saranac and market conditions at Sarnia.

(1) Gross margin, operating income, comparable earnings per share, EBITDA, cash flow from operating activities per share, and free cash flow 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 and cash flow from operating activities.

NET EARNINGS

The primary factors contributing to the change in net earnings for the three months ended March 31, 2010 are presented below:

	3 months ended March 31
Net earnings, 2009	42
Increase in Generation gross margins	24
Decrease in Energy Trading gross margins	(1)
Decrease in operations, maintenance, and administration costs	14
Decrease in depreciation expense	13
Increase in net interest expense	(15)
Decrease in other income	(7)
Decrease in non-controlling interest	9
Increase in income tax expense	(13)
Other	1
Net earnings, 2010	**67**

Generation gross margins increased for the three months ended March 31, 2010 compared to the same period in 2009 as a result of higher wind volumes due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro"), lower planned outages at the Keephills and Sundance plants, lower unplanned outages at the Sundance and Wabamun plants, 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, unfavourable foreign exchange rates, and unfavourable pricing.

For the three months ended March 31, 2010, Energy Trading gross margins decreased relative to the same period in 2009 as a result of reduced opportunities in the western region due to changes in the California market, and reduced customer demand due to lower market prices, partially offset by favourable positions on natural gas pricing in the eastern region.

Operations, maintenance, and administration ("OM&A") costs for the three months ended March 31, 2010 decreased compared to the same period in 2009 primarily 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 March 31, 2010 decreased compared to the same period in 2009 due to a reduction in the estimate of the costs associated with decommissioning our Wabamun plant, a change in estimated useful lives of certain coal generating facilities and mining assets, and lower production at Saranac, which is depreciated on a unit of production basis, partially offset by an increased asset base.

Net interest expense increased for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to higher debt levels.

For the three months ended March 31, 2010, non-controlling interest decreased compared to the same period in 2009 primarily due to lower earnings resulting from the expiration of the long-term contract at Saranac.

Income tax expense increased for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to higher pre-tax earnings.

CASH FLOW

Cash flow from operating activities for the three months ended March 31, 2010 increased $91 million compared to the same period in 2009 primarily due to more favourable movements in working capital.

Free cash flow for the three months ended March 31, 2010 increased $120 million compared to the same period in 2009 primarily due to more favourable movements in working capital.

SIGNIFICANT EVENTS

Three months ended March 31, 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 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 is in the process of conducting 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.

During the first quarter, management concluded its review of the coal fleet, as well as its mining assets, and has updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, in the current quarter, depreciation was reduced by $5 million versus the same period in 2009. The estimated annual impact of this change is $21 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.

SUBSEQUENT EVENTS

Centralia Thermal Memorandum of Understanding ("MOU")

On April 26, 2010, we announced that we have 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.

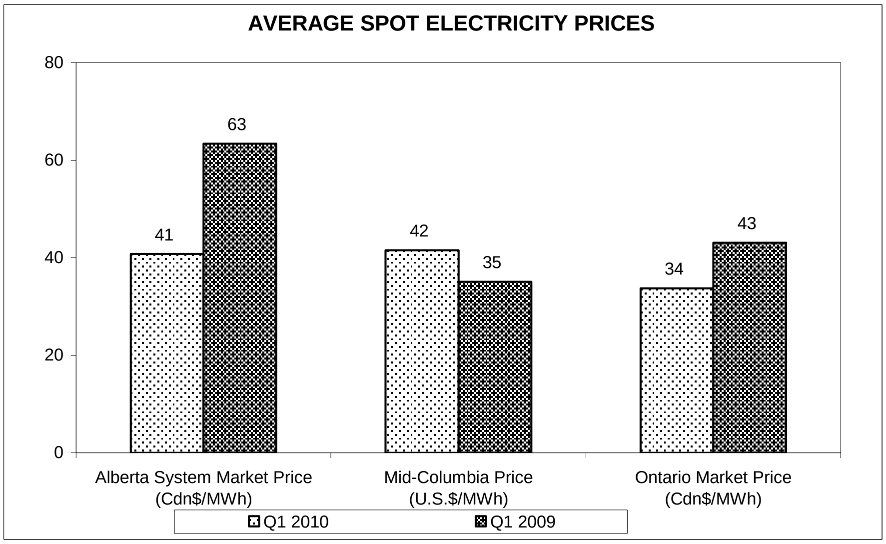
BUSINESS ENVIRONMENT

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

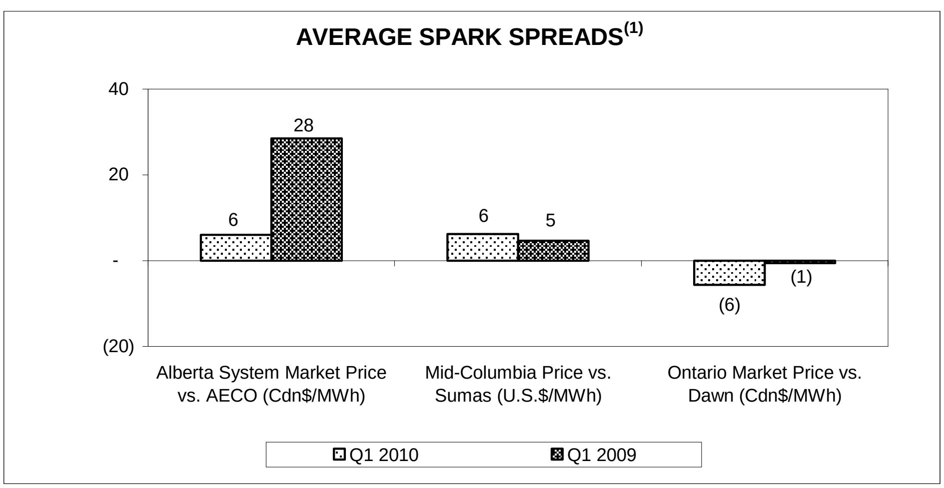
Please refer to the Business Environment section of the 2009 Annual Report for a full discussion of the spot electricity market and the impact of electricity prices upon our business and our strategy to hedge our risk on changes in those prices.

The average spot electricity prices and spark spreads for the three months ended March 31, 2010 and 2009 in our three major markets are shown in the following graphs.



For the three months ended March 31, 2010, average spot prices decreased in Alberta due to increased coal unit availability and additional supply that came into the market near the end of 2009. Prices in Ontario were lower due to lower regional natural gas prices and demand levels. Prices in the Pacific Northwest increased due to higher regional natural gas prices and low water conditions.

During the first quarter of 2010, our consolidated power portfolio was over 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/MWh in the Pacific Northwest. The use of these contracts reduced the impact of lower prices upon our consolidated financial results.



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

For the three months ended March 31, 2010, average spark spreads decreased in Alberta due to lower power prices. Ontario spark spreads were lower due to power prices falling more than gas prices. Spark spreads in the Pacific Northwest increased slightly due to low hydro conditions.

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 (see the detailed discussion of the four revenue streams in our 2009 Annual Report). 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. At March 31, 2010, Generation had 9,265 MW of gross generating capacity[(1)] in operation (8,841 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 March 31	**2010 Total**	**2010 Per installed MWh**	2009 Total	2009 Per installed MWh
Revenues	**712**	**35.58**	741	40.92
Fuel and purchased power	**322**	**16.09**	375	20.71
Gross margin	**390**	**19.49**	366	20.21
Operations, maintenance, and administration	**138**	**6.90**	146	8.06
Depreciation and amortization	**99**	**4.94**	111	6.13
Taxes, other than income taxes	**6**	**0.30**	5	0.28
Intersegment cost allocation	**1**	**0.05**	8	0.44
Operating expenses	**244**	**12.19**	270	14.91
Operating income	**146**	**7.30**	96	5.30
Installed capacity (GWh)	**20,010**		18,107	
Production (GWh)	**12,914**		12,173	
Availability (%)	**91.4**		86.4	

Production and Gross Margins

Generation's production volumes, electricity and steam production revenues, and fuel and purchased power costs based on geographical regions are presented below.

3 months ended March 31, 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	6,823	8,178	199	62	137	24.33	7.58	16.75
Gas	1,001	1,159	58	25	33	50.04	21.57	28.47
Renewables	605	2,744	32	2	30	11.66	0.73	10.93
Total Western Canada	**8,429**	**12,081**	**289**	**89**	**200**	**23.92**	**7.37**	**16.55**
Gas	797	1,620	112	61	51	69.14	37.65	31.49
Renewables	334	1,310	31	-	31	23.66	-	23.66
Total Eastern Canada	**1,131**	**2,930**	**143**	**61**	**82**	**48.81**	**20.82**	**27.99**
Coal	2,579	2,972	226	154	72	76.04	51.82	24.22
Gas	502	1,660	32	17	15	19.28	10.24	9.04
Renewables	273	367	22	1	21	59.95	2.72	57.23
Total International	**3,354**	**4,999**	**280**	**172**	**108**	**56.01**	**34.41**	**21.60**
	12,914	**20,010**	**712**	**322**	**390**	**35.58**	**16.09**	**19.49**

(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.

3 months ended March 31, 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	5,936	8,064	176	76	100	21.83	9.42	12.41
Gas	1,094	1,159	65	28	37	56.08	24.16	31.92
Renewables	500	2,057	32	1	31	15.56	0.49	15.07
Total Western Canada	7,530	11,280	273	105	168	24.20	9.31	14.89
Gas	938	1,620	114	73	41	70.37	45.06	25.31
Renewables	55	207	4	-	4	19.32	-	19.32
Total Eastern Canada	993	1,827	118	73	45	64.59	39.96	24.63
Coal	2,656	2,973	250	167	83	84.09	56.17	27.92
Gas	679	1,660	67	24	43	40.36	14.46	25.91
Renewables	315	367	33	6	27	89.92	16.35	73.57
Total International	3,650	5,000	350	197	153	70.00	39.40	30.60
	12,173	18,107	741	375	366	40.92	20.71	20.21

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 months ended March 31, 2010 are presented below:

	3 months ended March 31 (GWh)
Production, 2009	7,530
Lower planned outages at Keephills	403
Lower unplanned outages at Sundance	274
Lower planned outages at Sundance	203
Lower unplanned outages at Wabamun	56
Higher merchant volumes due to Sundance 5 uprate	114
Higher wind volumes primarily due to the acquisition of Canadian Hydro	106
Higher biomass volumes	32
Lower production at natural gas-fired facilities	(94)
Lower PPA customer demand	(89)
Higher unplanned outages at Sheerness	(50)
Lower hydro volumes	(35)
Other	(21)
Production, 2010	**8,429**

The primary factors contributing to the change in gross margin for the three months ended March 31, 2010 are presented below:

	3 months ended March 31
Gross margin, 2009	168
Lower planned outages at Keephills	25
Lower unplanned outages at Sundance	17
Lower planned outages at Sundance	13
Higher merchant volumes due to Sundance 5 uprate	5
Higher wind volumes primarily due to the acquisition of Canadian Hydro	3
Higher biomass volumes	3
Lower unplanned outages at Wabamun	2
Unfavourable pricing	(15)
Higher coal costs	(6)
Lower production at natural gas-fired facilities	(6)
Lower hydro volumes and prices	(5)
Higher unplanned outages at Sheerness	(4)
Gross margin, 2010	**200**

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 months ended March 31, 2010 increased 138 GWh primarily due to higher wind volumes as a result of the acquisition of Canadian Hydro, partially offset by market conditions at Sarnia.

For the three months ended March 31, 2010, gross margin increased $37 million 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 months ended March 31, 2010 are presented below:

	3 months ended March 31 (GWh)
Production, 2009	3,650
Expiration of Saranac contract	(143)
Higher unplanned outages at Centralia Thermal	(78)
Lower production at geothermal facilities	(40)
Lower production at natural gas-fired facilities	(34)
Other	(1)
Production, 2010	**3,354**

The primary factors contributing to the change in gross margin for the three months ended March 31, 2010 are presented below:

	3 months ended March 31
Gross margin, 2009	153
Expiration of Saranac contract	(23)
Unfavourable foreign exchange	(18)
Unfavourable pricing	(2)
Higher unplanned outages at Centralia Thermal	(2)
Gross margin, 2010	**108**

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 is depreciated on a unit of production basis, there is a corresponding $8 million decrease in depreciation expense from this lower level of production for the three months ended March 31, 2010. 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 $3 million for the three months ended March 31, 2010.

Operations, Maintenance and Administration Expense

OM&A costs for the three months ended March 31, 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

The primary factors contributing to the change in depreciation expense for the three months ended March 31, 2010 are presented below:

	3 months ended March 31
Depreciation and amortization expense, 2009	111
Reduction in decommissioning costs at Wabamun	(14)
Expiration of Saranac long-term contract	(8)
Favourable foreign exchange	(6)
Change in useful lives	(5)
Increased asset base	20
Other	1
Depreciation and amortization expense, 2010	**99**

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

Energy Trading is responsible for the management of commercial activities for our current generating assets. Energy Trading also manages available 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 March 31	**2010**	2009
Gross margin	**14**	15
Operations, maintenance, and administration	**4**	6
Depreciation and amortization	**-**	1
Intersegment cost recovery	**(1)**	(8)
Operating expenses	**3**	(1)
Operating income	**11**	16

For the three months ended March 31, 2010, gross margin decreased relative to the same period in 2009 as a result of reduced opportunities in the western region due to changes in the California market, and reduced customer demand due to lower market prices, partially offset by correct directional positions on natural gas pricing in the eastern region.

For the three months ended March 31, 2010, OM&A costs were consistent with the same period in 2009.

The intersegment cost recovery decreased for the three months ended March 31, 2010 as a result of support costs previously recovered through the intersegment fee being directly allocated to the Generation segment in 2010.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

3 months ended March 31	**2010**	2009
Interest on debt	**57**	43
Interest income	**-**	(2)
Capitalized interest	**(9)**	(8)
Net interest expense	**48**	33

The change in net interest expense for the three months ended March 31, 2010, compared to the same period in 2009 is shown below:

	3 months ended March 31
Net interest expense, 2009	33
Higher debt levels	21
Lower interest income	2
Favourable foreign exchange	(5)
Lower interest rates	(2)
Higher capitalized interest	(1)
Net interest expense, 2010	**48**

OTHER INCOME

During the first quarter of 2009, we settled an outstanding commercial issue related to our previously held Mexican equity investment and recorded a pre-tax gain of $7 million in other income.

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three months ended March 31, 2010 decreased $9 million 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 tax expense and effective tax rates is presented below:

3 months ended March 31	**2010**	2009
Earnings before income taxes	**84**	46
Other income	**-**	7
Earnings before income taxes and other income	**84**	39
Income tax expense	**17**	4
Effective tax rate on earnings before income taxes and other income (%)	**20**	10

Income tax expense increased for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to higher pre-tax earnings.

The effective tax rate on earnings before income taxes and other income increased for the three months ended March 31, 2010 compared to the same period in 2009 primarily due to certain deductions that do not fluctuate with earnings.

FINANCIAL POSITION

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

	Increase/ (Decrease)	Primary factors explaining change
Accounts receivable	(110)	Timing of customer receipts and lower revenues
Risk management assets (current and long-term)	151	Price movements
Property, plant, and equipment, net	(42)	Depreciation expense and foreign exchange, partially offset by capital additions
Accounts payable and accrued liabilities	(132)	Timing of payments, combined with lower operational and capital expenditures
Collateral received	76	Collateral collected from counterparties associated with their obligations as a result of a change in forward prices
Long-term debt (including current portion)	(94)	Repayment of long-term debt and favourable foreign exchange rates
Asset retirement obligation (including current portion)	(26)	Revised cost estimate of the decommissioning of our Wabamun plant and foreign exchange
Net future income tax liabilities (including current portions)	67	Tax effect on the increase in net risk management assets
Shareholders' equity	101	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 the interim consolidated financial statements as at and for the three months ended March 31, 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 March 31, 2010, Level III financial instruments had a net liability carrying value of $17 million (Dec. 31, 2009 – $26 million).

STATEMENTS OF CASH FLOWS

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the three months ended March 31, 2010 compared to the three months ended March 31, 2009:

3 months ended March 31	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**82**	50	
Provided by (used in):			
Operating activities	**174**	83	Favourable movements in working capital of $92 million.
Investing activities	**(53)**	63	Decrease in the amount of collateral received from counterparties of $112 million.
Financing activities	**(118)**	(148)	Proceeds from the issuance of senior notes of $301 million, partially offset by an increase in the repayment of credit facilities of $251 million and an increase in realized losses on financial instruments of $17 million.
Translation of foreign currency cash	**(1)**	1	
Cash and cash equivalents, end of period	**84**	49	

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

Debt

Recourse and non-recourse debt totalled $4.3 billion at March 31, 2010 compared to $4.4 billion at Dec. 31, 2009. Total debt decreased from Dec. 31, 2009 primarily due to the repayment of our credit facilities and favourable foreign exchange rates.

Credit Facilities

We have a total of $2.1 billion of committed credit facilities of which $1.1 billion is available as of March 31, 2010, subject to customary borrowing conditions. The $1.0 billion of credit utilized under these facilities is comprised of actual drawings of $0.7 billion and of letters of credit of $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 2011 and 2013. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Share Capital

On April 26, 2010, we had 218.8 million common shares outstanding.

At March 31, 2010, we had 218.6 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended March 31, 2010, 0.2 million (March 31, 2009 – 0.2 million) common shares were issued for proceeds of $1 million (March 31, 2009 – nil).

During the three months ended March 31, 2010 and 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid program.

We employ a variety of stock-based compensation to align employee and corporate objectives. At March 31, 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 March 31, 2010, a nominal number of options also expired, or were exercised or cancelled (March 31, 2009 – 0.1 million expired).

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties including those related to potential environmental obligations, energy trading activities, hedging activities, and purchase obligations. At March 31, 2010, we provided letters of credit totalling $341 million (Dec. 31, 2009 – $334 million) and cash collateral of $32 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 Jan. 31, 2010, the Government of Canada announced its national goal of a 17 per cent GHG reduction from a 2005 baseline by 2020. However, the federal government has not yet implemented a framework or regulations to achieve those goals. At this point, it appears that the details and schedule of the Canadian program will depend on the development and direction of the U.S. approach.

Separately, the Government of Canada has announced its intent to develop new Canadian air pollutant requirements for sulphur dioxide, nitrogen oxide, and mercury. Stakeholder consultations involving industry, provincial and federal governments, and environmental organizations are underway. There is currently no defined date for the finalization and implementation of any recommendations.

United States

In the U.S., there have been continuing efforts over the last year to draft climate change legislation in the Senate. To date, none of these legislative efforts have been successful in moving forward and the prospect of legislation being passed in 2010 appears to be lessening.

Meanwhile, the U.S. Environmental Protection Agency (“EPA”) is pursuing a separate path to regulate GHGs under the Clean Air

Act. On March 29, 2010, the EPA stated its intent to have a regulatory mechanism and permitting requirements for GHGs for large stationary sources in place by January 2011. It is not clear whether or not existing power facilities will require emission reductions at this time.

In Washington State, Governor Gregoire signed an Executive Order in 2009 that outlines the state’s plan for addressing climate change related emissions. In the Executive Order, the Governor included a directive to the State Department of Ecology to work with us to apply the state's GHG performance standard for power generation to the Centralia Thermal plant no later than 2025. That standard would require emissions reductions of approximately 0.5 tonnes/MWh, or about half of what is currently emitted at Centralia Thermal. As a result of the Executive Order, we signed an MOU with Governor Gregoire on April 26, 2010.

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 low 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 remain at or slightly above 2009 levels due to the influence of low natural gas prices and minimal demand growth. In the Alberta market, the longer-term fundamentals of the market remain strong and the recovery of the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices will be the main driver behind the recovery of power prices. Natural gas prices are expected to remain low until 2011.

Environmental Legislation

The state of development of emissions regulations in both Canada and the U.S. remains fluid. Canada has expressed its intention to coordinate the timing and structure of its regulatory framework with the U.S. In the U.S., it is not clear if climate change legislation will prevail or if instead regulation will 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 Power Purchase Agreements (“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 decrease for the remainder of 2010 due to the decommissioning of our Wabamun plant, partially offset by 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. While wind volumes were 30 per cent lower than what was expected during the first quarter, but we expect to recover some of this shortage over the balance of the year. 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 approximately 90 per cent.

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 first quarter, approximately 90 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 megawatt hour ("MWh") in Alberta, and from U.S.$50-$55/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.

In 2010, approximately 20 per cent of our fuel at our natural gas-fired facilities and seven per cent of our fuel at our coal-fired facilities is exposed to market fluctuations in energy commodity prices. 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 remain flat compared to 2009 as costs related to Canadian Hydro are expected to be 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 maximize earnings while still maintaining an acceptable risk profile. Our 2010 objective is for Energy Trading to contribute between $50 million and $70 million in gross margin.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the U.S. dollar 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 earnings.

Net Interest Expense

Net interest expense for 2010 is expected to be higher 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 do not anticipate significant changes to these estimates as a result of the current economic environment, market fluctuations could impact, among other things, future commodity prices, foreign exchange rates, and interest rates, which could, in turn, impact future earnings and the unrealized gains or losses associated with our risk management assets and liabilities. The unrealized gains or losses related to our risk management assets and liabilities are not expected to impact our expected cash flows as they are generally settled at the contracted prices.

Income Taxes

The effective tax rate for 2010 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			
Project	**Estimated spend**	**Incurred to date(1)**	**Estimated spend**	**Incurred to date(1)**	**Target completion date**	**Details**
Keephills 3	988	768	225 - 245	61	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	116	15 - 25	10	Commercial operations began Q1 2010	A 66 MW expansion of our Summerview wind farm in southern Alberta
Keephills Unit 1 uprate	34	2	5 - 10	1	Q4 2011	A 23 MW efficiency uprate at our Keephills facility
Keephills Unit 2 uprate	34	2	0 - 5	1	Q4 2012	A 23 MW efficiency uprate at our Keephills facility
Ardenville	135	29	95 - 105	2	Q1 2011	A 69 MW wind farm in southern Alberta
Bone Creek	48	6	40 - 45	2	Q1 2011	An 18 MW hydro facility in British Columbia
Kent Hills 2	100	18	80 - 85	-	Q4 2010	A 54 MW expansion of our wind farm in New Brunswick
Total growth	**1,462**	**941**	**460 - 520**	**77**		

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

(1) Represents amounts incurred as of March 31, 2010.

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	24
Productivity capital	Projects to improve power production efficiency	10 - 15	3
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	25 - 30	-
Planned maintenance	Regularly scheduled major maintenance	140 - 155	18
Total sustaining expenditures		**295 - 340**	45

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

	Coal	Gas	Renewables	Expected cost	Incurred to date[1]
Capitalized	70 - 75	45 - 50	25 - 30	**140 - 155**	18
Expensed	60 - 65	0 - 5	-	**60 - 70**	9
	130 - 140	45 - 55	25 - 30	**200 - 225**	27

	Coal	Gas	Renewables	Total	Incurred to date [1]
GWh lost	1,770 - 1,780	360 - 370	-	**2,130 - 2,150**	121

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 solid financial position, and the amount of capital available to us under existing committed credit facilities.

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 March 31, 2010, TAGP had received $55 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.

(1) Represents amounts incurred as of March 31, 2010.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The total value of these contracts are U.S.$3 million for the year ending Dec. 31, 2010 (Dec. 31, 2009 – U.S.$3 million).

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.

Based on the work to date, our view is that 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. The majority of differences for us are expected to arise in respect to:

- Additional disclosure reconciling the changes in individual classes of property, plant, and equipment and accumulated amortization,
- Costs related to major inspection activities currently being expensed will be recognized as part of the carrying value of property, plant, and equipment and depreciated over the period until the next major inspection,
- Allowing an entity to recognize as at Jan. 1, 2010, all experience and transitional gains and losses related to employee future benefits to retained earnings with subsequent experience gains and losses being recorded in other comprehensive income, and
- Certain long-term contracts being deemed finance leases resulting in the associated property, plant, and equipment being 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. Payments received under the contract are recorded in revenue and interest income, dependent upon the interest rate and duration of the contract.

As we implement our 2010 dual reporting, we continue to evaluate the transitional options available under IFRS 1, *First-Time Adoption of International Financial Reporting Standards* as well as the most appropriate long-term accounting policies available under IFRS.

In 2010, the International Accounting Standards Board ("IASB") is expected to issue new guidance on the accounting for joint ventures. Under the issued exposure draft, certain joint ventures cannot be proportionately consolidated and must instead be accounted for as an equity investment on the balance sheet with the associated net income or loss from these joint ventures being recorded as equity earnings on the statement of earnings.

At this time, it is not anticipated that any other material new standards or amendments relating to these projects will be effective on convergence in 2011. However, the progress and recommendations of other 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 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 Reconciliation

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

3 months ended March 31	**2010**	2009
Revenues	**726**	756
Fuel and purchased power	**322**	375
Gross margin	**404**	381
Operations, maintenance, and administration	**160**	174
Depreciation and amortization	**104**	117
Taxes, other than income taxes	**6**	5
Operating expenses	**270**	296
Operating income	**134**	85
Foreign exchange gain	**3**	1
Net interest expense	**(48)**	(33)
Other income	**-**	7
Earnings before non-controlling interests and income taxes	**89**	60
Non-controlling interests	**5**	14
Earnings before income taxes	**84**	46
Income tax expense	**17**	4
Net earnings	**67**	42

Earnings 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 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 March 31	**2010**	2009
Net earnings	**67**	42
Settlement of commercial issue, net of tax	**-**	(7)
Change in life of Centralia parts, net of tax	**-**	1
Earnings on a comparable basis	**67**	36
Weighted average common shares outstanding in the period	**219**	198
Earnings on a comparable basis per share	**0.31**	0.18

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 March 31	**2010**	2009
Operating income	**134**	85
Asset retirement obligation per the Consolidated Statements of Cash Flows	**5**	6
Depreciation and amortization per the Consolidated Statements of Cash Flows[1]	**110**	121
EBITDA	**249**	212

Cash Flow from Operating Activities per Share

Presenting cash flow per share from period to period provides management and investors with a proxy for the amount of cash generated from operating activities 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 March 31	**2010**	2009
Cash flow from operating activities	**174**	83
Weighted average common shares outstanding during the period	**219**	198
Cash flow from operating activities per share	**0.79**	0.42

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 March 31, 2010, represents total additions to property, plant, and equipment per the Consolidated Statements of Cash Flows less $81 million ($77 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2009, we invested $62 million ($57 million net of joint venture contributions) in growth projects.

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

3 months ended March 31	**2010**	2009
Cash flow from operating activities	**174**	83
Add (Deduct):		
Sustaining capital expenditures	**(45)**	(69)
Dividends paid on common shares	**(59)**	(54)
Distributions paid to subsidiaries' non-controlling interests	**(14)**	(16)
Non-recourse debt repayments[2]	**-**	(1)
Other income	**-**	(7)
Free cash flow (deficiency)	**56**	(64)

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

(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 and Retained Earnings.
(2) 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.

SELECTED QUARTERLY INFORMATION

	Q2 2009	Q3 2009	Q4 2009	**Q1 2010**
Revenue	585	666	763	**726**
Net earnings (loss)	(6)	66	79	**67**
Basic and diluted earnings (loss) per common share	(0.03)	0.34	0.37	**0.31**
Comparable earnings (loss) per common share	(0.03)	0.34	0.40	**0.31**
	Q2 2008	Q3 2008	Q4 2008	Q1 2009
Revenue	708	791	808	756
Net earnings	47	61	94	42
Basic and diluted earnings per common share	0.24	0.31	0.47	0.21
Comparable earnings per common share	0.25	0.32	0.40	0.18

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

DISCLOSURE CONTROLS AND PROCEDURES

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

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 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; 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; expected governmental regulatory regimes and legislation; our trading strategy and the risk involved in these strategies; 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 AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	3 months ended March 31	
Unaudited	**2010**	2009
Revenues	**726**	756
Fuel and purchased power	**322**	375
	404	381
Operations, maintenance, and administration	**160**	174
Depreciation and amortization *(Note 20)*	**104**	117
Taxes, other than income taxes	**6**	5
	270	296
	134	85
Foreign exchange gain	**3**	1
Net interest expense *(Note 10)*	**(48)**	(33)
Other income *(Note 3)*	**-**	7
Earnings before non-controlling interests and income taxes	**89**	60
Non-controlling interests *(Note 4)*	**5**	14
Earnings before income taxes	**84**	46
Income tax expense *(Note 5)*	**17**	4
Net earnings	**67**	42
Retained earnings		
Opening balance	**634**	688
Common share dividends	**63**	57
Closing balance	**638**	673
Weighted average number of common shares outstanding in the period	**219**	198
Net earnings per share, basic and diluted	**0.31**	0.21

See accompanying notes.

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

Unaudited	**March 31, 2010**	Dec. 31, 2009
Cash and cash equivalents *(Note 6)*	**84**	82
Accounts receivable *(Notes 6 and 18)*	**311**	421
Collateral paid *(Notes 6 and 7)*	**32**	27
Prepaid expenses	**27**	18
Risk management assets *(Notes 6 and 7)*	**217**	144
Future income tax assets	**17**	17
Income taxes receivable	**37**	39
Inventory *(Note 8)*	**76**	90
	801	838
Long-term receivables	**49**	49
Property, plant, and equipment		
Cost	**11,754**	11,721
Accumulated depreciation	**(4,218)**	(4,143)
	7,536	7,578
Goodwill *(Note 20)*	**431**	434
Intangible assets	**321**	333
Future income tax assets	**158**	204
Risk management assets *(Notes 6 and 7)*	**302**	224
Other assets *(Note 9)*	**109**	102
Total assets	**9,707**	9,762
Accounts payable and accrued liabilities *(Note 6)*	**389**	521
Collateral received *(Notes 6 and 7)*	**162**	86
Risk management liabilities *(Notes 6 and 7)*	**46**	45
Income taxes payable	**12**	10
Future income tax liabilities	**55**	57
Dividends payable	**65**	61
Current portion of long-term debt - recourse *(Notes 6 and 10)*	**9**	7
Current portion of long-term debt - non-recourse *(Notes 6 and 10)*	**23**	24
Current portion of asset retirement obligation *(Note 11)*	**30**	32
	791	843
Long-term debt - recourse *(Notes 6 and 10)*	**3,767**	3,857
Long-term debt - non-recourse *(Notes 6 and 10)*	**549**	554
Asset retirement obligation *(Note 11)*	**226**	250
Deferred credits and other long-term liabilities	**143**	136
Future income tax liabilities	**660**	637
Risk management liabilities *(Notes 6 and 7)*	**72**	78
Non-controlling interests *(Note 4)*	**469**	478
Shareholders' equity		
Common shares *(Notes 12 and 13)*	**2,174**	2,169
Retained earnings *(Note 13)*	**638**	634
Accumulated other comprehensive income *(Note 13)*	**218**	126
Total shareholders' equity	**3,030**	2,929
Total liabilities and shareholders' equity	**9,707**	9,762

Contingencies *(Notes 16 and 18)*
Commitments *(Notes 6 and 17)*
Subsequent events *(Note 23)*

See accompanying notes.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2010**	2009
Net earnings	**67**	42
Other comprehensive income		
(Losses) gains on translating net assets of self-sustaining foreign operations	**(50)**	62
Gains (losses) on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1)	**36**	(43)
Gains on derivatives designated as cash flow hedges, net of tax(2)	**116**	189
Reclassification of derivatives designated as cash flow hedges to balance sheet, net of tax(3)	**17**	(3)
Reclassification of derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(27)**	(24)
Other comprehensive income	**92**	181
Comprehensive income	**159**	223

(1) Net of income tax expense of 5 million for the three months ended March 31, 2010 (2009 - 7 million recovery).

(2) Net of income tax expense of 59 million for the three months ended March 31, 2010 (2009 - 92 million expense).

(3) Net of income tax expense of 6 million for the three months ended March 31, 2010 (2009 - 1 million recovery).

(4) Net of income tax recovery of 12 million for the three months ended March 31, 2010 (2009 - 14 million recovery).

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended March 31	
Unaudited	**2010**	2009
Operating activities		
Net earnings	**67**	42
Depreciation and amortization *(Note 20)*	**110**	121
Non-controlling interests	**5**	14
Asset retirement obligation accretion *(Note 11)*	**5**	6
Asset retirement costs settled *(Note 11)*	**(5)**	(8)
Future income taxes	**11**	19
Unrealized foreign exchange gain	**(3)**	(3)
Unrealized gain from risk management activities	**(3)**	-
Other non-cash items	**3**	-
	190	191
Change in non-cash operating working capital balances *(Note 21)*	**(16)**	(108)
Cash flow from operating activities	**174**	83
Investing activities		
Additions to property, plant, and equipment	**(126)**	(131)
Proceeds on sale of property, plant, and equipment	**2**	1
Restricted cash	**-**	(1)
Realized losses on financial instruments	**(7)**	(6)
Net increase in collateral received from counterparties	**80**	192
Net (increase) decrease in collateral paid to counterparties	**(6)**	9
Settlement of adjustments on sale of Mexican equity investment *(Note 3)*	**-**	(7)
Other	**4**	6
Cash flow (used in) from investing activities	**(53)**	63
Financing activities		
Net decrease in credit facilities	**(327)**	(76)
Repayment of long-term debt	**(2)**	(2)
Issuance of long-term debt *(Note 10)*	**301**	-
Dividends paid on common shares	**(59)**	(54)
Net proceeds on issuance of common shares *(Note 12)*	**1**	-
Realized losses on financial instruments	**(17)**	-
Distributions paid to subsidiaries' non-controlling interests	**(14)**	(16)
Other	**(1)**	-
Cash flow used in financing activities	**(118)**	(148)
Cash flow used in operating, investing, and financing activities	**3**	(2)
Effect of translation on foreign currency cash	**(1)**	1
Increase (decrease) in cash and cash equivalents	**2**	(1)
Cash and cash equivalents, beginning of period	**82**	50
Cash and cash equivalents, end of period	**84**	49
Cash taxes paid	**7**	23
Cash interest paid	**17**	15

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

Change in Estimate - Useful Lives

Management is in the process of conducting 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.

During the first quarter, management concluded its review of the coal fleet, as well as its mining assets, and has updated the estimated useful lives of these assets to reflect their current expected economic lives. As a result, in the current quarter, depreciation was reduced by $5 million versus the same period in 2009. The estimated annual impact of this change is $21 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 first 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.

3. OTHER INCOME

In 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	(14)
Non-controlling interests portion of net earnings	5
Balance, March 31, 2010	**469**

5. INCOME TAX EXPENSE

The components of income tax expense are as follows:

	3 months ended March 31	
	2010	2009
Current tax expense (recovery)	**6**	(15)
Future income tax expense	**11**	19
Income tax expense	**17**	4

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 March 31, 2010

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	84	-	84
Accounts receivable	-	-	311	-	311
Collateral paid	-	-	32	-	32
Risk management assets					
Current	197	20	-	-	217
Long-term	297	5	-	-	302
Financial liabilities			.		
Accounts payable and accrued liabilities	-	-	-	389	389
Collateral received	-	-	-	162	162
Risk management liabilities					
Current	27	19	-	-	46
Long-term	70	2	-	-	72
Long-term debt - recourse(1)	-	-	-	3,776	3,776
Long-term debt - non-recourse(1)	-	-	-	572	572

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.

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[1] *The Energy Trading segment was referred to as "Commercial Operations and Development" in prior periods.*

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 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 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 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 three months ended March 31, 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:									
Commodity price changes	-	158	12	4	2	(1)	4	160	11
New contracts entered	-	22	-	(4)	1	-	(4)	23	-
Contracts settled	-	(30)	(2)	-	1	-	-	(29)	(2)
Change in foreign exchange rates	-	(6)	-	-	-	-	-	(6)	-
Transfers in/out of Level III	-	-	-	-	-	-	-	-	-
Net risk management assets (liabilities) at March 31, 2010	-	**441**	**(17)**	-	**4**	-	-	**445**	**(17)**
Additional Level III gain (loss) information:									
Change in fair value included in OCI			10			(1)			9
Realized gain (loss) included in earnings before income taxes			2						2
Unrealized gain (loss) included in earnings before income taxes relating to those net assets held at March 31, 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 March 31, 2010 is estimated to be +/- $20 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 March 31, 2010, that was recognized in pre-tax earnings for the three months ended March 31, 2010 was nil (March 31, 2009 - $1 million gain).

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	136	164	118	24	(1)	-	**441**
	Level III	4	6	2	-	1	(30)	**(17)**
Non-hedges	Level I	-	-	-	-	-	-	**-**
	Level II	6	(3)	-	1	-	-	**4**
	Level III	-	-	-	-	-	-	**-**
Total by level	Level I	-	-	-	-	-	-	**-**
	Level II	142	161	118	25	(1)	-	**445**
	Level III	4	6	2	-	1	(30)	**(17)**
Total net assets (liabilities)		**146**	**167**	**120**	**25**	**-**	**(30)**	**428**

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 three months ended March 31, 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	-	(8)	-	-	-	-	-	(8)	-
New contracts entered	-	(7)	-	-	-	-	-	(7)	-
Contracts settled	-	12	-	-	2	-	-	14	-
Net risk management liabilities at March 31, 2010	**-**	**(27)**	**-**	**-**	**-**	**-**	**-**	**(27)**	**-**

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	(14)	6	(2)	(3)	-	(14)	**(27)**
	Level III	-	-	-	-	-	-	**-**
Total net (liabilities) assets		**(14)**	**6**	**(2)**	**(3)**	**-**	**(14)**	**(27)**

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

	Fair value(1)				Total carrying
As at March 31, 2010	**Level I**	**Level II**	**Level III**	**Total**	**value**
Financial assets and liabilities measured at other than fair value					
Long-term debt - March 31, 2010(2)	-	4,478	-	4,478	4,348
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 Energy Trading 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	**March 31, 2010**	March 31, 2009
Unamortized (loss) gain at beginning of period	**(1)**	2
New transactions	**(1)**	1
Amortization recorded in net earnings during the period	**1**	(2)
Unamortized (loss) gain at beginning of period	**(1)**	1

7. RISK MANAGEMENT ACTIVITIES

A. Risk Management Assets and Liabilities

Aggregate risk management assets and liabilities are as follows:

As at	March 31, 2010					Dec. 31, 2009
	Net Investment Hedges	**Cash Flow Hedges**	**Fair Value Hedges**	**Not Designated as a Hedge**	**Total**	Total
Risk management assets						
Current - Energy Trading	-	196	-	17	213	144
Long-term - Energy Trading	-	281	-	5	286	207
Total Energy Trading risk management assets	-	477	-	22	499	351
Current - other	1	-	-	3	4	-
Long-term - other	-	-	16	-	16	17
Total other risk management assets	1	-	16	3	20	17
Risk management liabilities						
Current - Energy Trading	-	12	-	16	28	30
Long-term - Energy Trading	-	41	-	2	43	50
Total Energy Trading risk management liabilities	-	53	-	18	71	80
Current - other	5	10	-	3	18	15
Long-term - other	-	29	-	-	29	28
Total other risk management liabilities	5	39	-	3	47	43
Net Energy Trading risk management assets	**-**	**424**	**-**	**4**	**428**	271
Net other risk management (liabilities) assets	**(4)**	**(39)**	**16**	**-**	**(27)**	(26)
Net total risk management (liabilities) assets	**(4)**	**385**	**16**	**4**	**401**	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.$800 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:

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

Foreign Currency Contracts

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

March 31, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
AUD125	**-**	**2010**	AUD120	(2)	2010
U.S.(8)	**(2)**	**2010**	U.S.(182)	(1)	2010

ii. Effect on Consolidated Statements of Comprehensive Income

For the three months ended March 31, 2010, a net after-tax loss of $14 million (March 31, 2009 – gain of $19 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").

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 for the three months ended March 31, 2010 and 2009:

Derivatives in net investment hedging relationships	**Pre-tax gain (loss) recognized in OCI for the 3 months ended March 31, 2010**	Pre-tax loss recognized in OCI for the 3 months ended March 31, 2009
Long-term debt	**48**	(50)
Foreign exchange	**(7)**	-
OCI impact	**41**	(50)

b. Cash flow hedges

i. Energy Trading Risk Management

The Corporation's outstanding Energy Trading derivative instruments designated as hedging instruments at March 31, 2010, were as follows:

	March 31, 2010		Dec. 31, 2009	
Type	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**67,301**	**-**	175,756	-
Natural gas (GJ)	**1,933**	**1,808**	2,163	360
Oil (gallons)	**-**	**21,042**	-	25,074

ii. Foreign Currency Rate Risk Management

Foreign Exchange Forward Contracts on Foreign Denominated Exposures

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

March 31, 2010				Dec. 31, 2009			
Amount sold	**Amount purchased**	**Fair value liability**	**Maturity**	Amount sold	Amount purchased	Fair value liability	Maturity
79	**U.S.68**	**(10)**	**2010**	91	U.S.78	(8)	2010
U.S.10	**11**	**-**	**2010**	U.S.14	15	-	2010
AUD2	**U.S.2**	**-**	**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:

March 31, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
U.S.300	**(2)**	**2012**	-	-	-
U.S.300	**(3)**	**2013**	-	-	-

Cross-Currency Swap

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

March 31, 2010			Dec. 31, 2009		
Notional amount	**Fair value liability**	**Maturity**	Notional amount	Fair value liability	Maturity
U.S.500	**(24)**	**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 quarter and the resulting losses have been included in AOCI and will be recognized over the term of the senior notes.

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

iv. Effect on Consolidated Statements of Comprehensive Income

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, Consolidated Statements of Earnings, and the Consolidated Balance Sheets for the three months ended March 31, 2010 and 2009:

3 months ended March 31, 2010

Effective 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**
Commodity	**201**	Revenue	**(39)**
Foreign exchange	**(7)**	Foreign exchange gain (loss)	**-**
Cross-currency swaps	**(10)**	Property, plant, and equipment	**23**
Interest rate	**(9)**	Interest expense	**-**
OCI impact	**175**	**OCI impact**	**(16)**

3 months ended March 31, 2009

Effective portion

Derivatives in cash flow hedging relationships	Pre-tax gain recognized in OCI	Location of loss reclassified from OCI	Pre-tax loss reclassified from OCI
Commodity	280	Revenue	(38)
Foreign exchange	1	Foreign exchange gain (loss)	-
Cross-currency swaps	-	Property, plant, and equipment	(4)
Interest rate	-	Interest expense	-
OCI impact	281	OCI impact	(42)

Over the next 12 months, the Corporation estimates that $118 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 6.65 per cent, to floating rate debt through interest rate swaps as shown below:

March 31, 2010			Dec. 31, 2009		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset (liability)	Maturity
100	**6**	**2011**	100	7	2011
U.S.100	**-**	**2013**	U.S.50	(1)	2013
U.S.400	**10**	**2018**	U.S.150	7	2018

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

ii. Effect on Consolidated Statements of Comprehensive Income

No ineffective portion of fair value hedges was recorded for the three months ended March 31, 2010 and 2009.

The following table summarizes the impact and location of fair value hedges on the Consolidated Statements of Earnings for the three months ended March 31, 2010 and 2009:

Derivatives in fair value hedging relationships	**Location of gain (loss) on statements of earnings**	**3 months ended March 31, 2010**	3 months ended March 31, 2009
Interest rate contracts	Interest expense	**2**	2
Long-term debt	Interest expense	**(2)**	(2)
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 March 31, 2010, were as follows:

	March 31, 2010		Dec. 31, 2009	
Type	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	22,193	20,385	14,107	14,844
Natural gas (GJ)	435,014	435,692	323,793	309,764
Transmission (MWh)	-	4,114	-	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:

March 31, 2010			Dec. 31, 2009		
Notional amount	Fair value liability	Maturity	Notional amount	Fair value liability	Maturity
AUD13	(2)	2010	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 sales (purchases) are as follows:

March 31, 2010			Dec. 31, 2009		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value liability	Maturity
AUD19	-	2010	-	-	-
U.S.46	2	2010	U.S.13	-	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 Consolidated Statements of Comprehensive Income

The table 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 March 31					
	2010			2009		
	Net unrealized gains	**Net realized gains**	**Total**	Net unrealized gains	Net realized gains (losses)	Total
Commodity	**5**	**10**	**15**	1	10	11
Interest	**-**	**-**	**-**	1	(1)	-
Foreign exchange	**1**	**1**	**2**	1	(6)	(5)
Other	**-**	**-**	**-**	-	(3)	(3)

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 March 31, 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 March 31, 2010 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $33 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 March 31, 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.

	3 months ended March 31			
	2010		2009	
	Net earnings increase(1)	**OCI loss(1)**	Net earnings increase(1)	OCI loss(1)
50 basis point change	2	-	1	(2)

(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.

	3 months ended March 31			
	2010		2009	
Currency	**Net earnings decrease(1)**	**OCI gain(1,2)**	Net earnings decrease(1)	OCI gain(1,2)
Euro	-	-	-	3
U.S.	(3)	2	(3)	2
AUD	(2)	-	(2)	-
Total	**(5)**	**2**	(5)	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 March 31, 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 March 31, 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 March 31, 2010 was $54 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 March 31, 2010:

	Investment grade %	**Non-investment grade %**	**Total %**
Accounts receivable	94	6	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	March 31, 2010	Dec. 31, 2009
Allowance at beginning of period	**49**	57
Change in foreign exchange rates	**(2)**	(8)
Allowance at end of period	**47**	49

At March 31, 2010, the Corporation did not have any significant past due trade receivables except as disclosed in Note 18.

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	389	-	-	-	-	-	389
Collateral received	162	-	-	-	-	-	162
Debt(1)	29	253	755	640	231	2,476	4,384
Energy Trading risk management (assets) liabilities(2)	(146)	(167)	(120)	(25)	-	30	(428)
Other risk management liabilities (assets)(2)	14	(6)	2	3	-	14	27
Interest on long-term debt	236	255	233	211	179	1,136	2,250
Total	**684**	**335**	**870**	**829**	**410**	**3,656**	**6,784**

(1) Excludes impact of hedge accounting and includes 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 March 31, 2010, $42 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 March 31, 2010, the Corporation provided $32 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 March 31, 2010, the Corporation received $162 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 March 31, 2010 the Corporation had posted collateral of $19 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 March 31, 2010, the Corporation would be required to post an additional $25 million of collateral to its counterparties.

8. INVENTORY

Inventory includes coal, natural gas, and emission credits which are valued at the lower of cost and net realizable value. The classifications are as follows:

As at	**March 31, 2010**	Dec. 31, 2009
Coal	**71**	86
Natural gas	**5**	4
Total	**76**	90

The decrease in coal inventory at March 31, 2010 compared to Dec. 31, 2009 is primarily due to higher production at the Alberta Thermal plants.

The change in inventory is outlined below:

Balance, Dec. 31, 2009	90
Consumed	(13)
Change in foreign exchange rates	(1)
Balance, March 31, 2010	**76**

No inventory is pledged as security for liabilities.

For the three months ended March 31, 2009, no inventory was written down from its carrying value nor were any writedowns recorded in previous periods reversed back into net earnings.

9. OTHER ASSETS

The components of other assets are as follows:

As at	**March 31, 2010**	Dec. 31, 2009
Deferred license fees	**22**	22
Accrued pension benefit asset	**19**	18
Project development costs	**47**	45
Keephills 3 transmission deposit	**8**	8
Other	**13**	9
Total other assets	**109**	102

10. LONG-TERM DEBT AND NET INTEREST EXPENSE

The amounts outstanding are as follows:

As at	**March 31, 2010**			Dec. 31, 2009		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**726**	**726**	**1.0%**	1,063	1,063	1.0%
Debentures, due 2011 to 2030	**1,052**	**1,076**	**6.7%**	1,055	1,076	6.7%
Senior notes[3]	**1,941**	**1,936**	**6.0%**	1,687	1,684	5.9%
Non-recourse	**572**	**589**	**6.6%**	578	581	6.3%
Other	**57**	**57**	**6.7%**	59	59	6.7%
	4,348	**4,384**		4,442	4,463	
Less: current portion	**32**	**32**		31	31	
Total long-term debt	**4,316**	**4,352**		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 March 31	
	2010	2009
Interest on debt	**57**	43
Interest income	**-**	(2)
Capitalized interest	**(9)**	(8)
Net interest expense	**48**	33

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

11. 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	(5)
Accretion expense	5
Revisions in estimated cash flows[1]	(24)
Change in foreign exchange rates	(3)
	256
Less: current portion	30
Balance, March 31, 2010	**226**

(1) Revisions are primarily due to changes in the estimates and timing of cash flows of the decommissioning plan of the Wabamun plant as a result of ongoing detailed costing. This plant was shut down on March 31, 2010.

12. 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 March 31, 2010, the Corporation had 218.6 million (Dec. 31, 2009 – 218.4 million) common shares issued and outstanding. During the three months ended March 31, 2010, 0.2 million (March 31, 2009 – 0.2 million) common shares were issued for proceeds of $1 million (March 31, 2009 – nil).

During the three months ended March 31, 2010 and 2009, no shares were acquired or cancelled under the Normal Course Issuer Bid (“NCIB”) program.

B. Stock options

At March 31, 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 March 31, 2010, a nominal number of options also expired, or were exercised or cancelled (March 31, 2009 – 0.1 million expired).

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 months ended March 31, 2010, stock based compensation expense related to stock options recorded in operations, maintenance, and administration expense was $0.5 million (March 31, 2009 – $0.7 million).

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. Shares purchased under the DRASP plan are acquired in the open market at 100 per cent of the average purchase price of common shares acquired on the Toronto Stock Exchange on the investment dates.

13. 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	-	67	-	67
Common shares issued	5	-	-	5
Dividends declared	-	(63)	-	(63)
Losses on translating net assets of self-sustaining foreign operations, net of hedges and of tax	-	-	(14)	(14)
Gains on derivatives designated as cash flow hedges, net of tax	-	-	116	116
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	-	-	(10)	(10)
Balance, March 31, 2010	**2,174**	**638**	**218**	**3,030**

The components of AOCI are presented below:

As at	March 31, 2010	Dec. 31, 2009
Cumulative unrealized losses on translating self-sustaining foreign operations, net of hedges and of tax	**(76)**	(63)
Cumulative unrealized gains on cash flow hedges, net of tax	**294**	189
Total accumulated other comprehensive income	**218**	126

Normal Course Issuer Bid Program

No purchases were made under the NCIB program through March 31, 2010.

14. CAPITAL

TransAlta's capital is comprised of the following:

As at	March 31, 2010	Dec. 31, 2009	Increase/ (decrease)
Current portion of long-term debt	**32**	31	1
Less: cash and cash equivalents	**(84)**	(82)	(2)
	(52)	(51)	(1)
Long-term debt			
Recourse	**3,767**	3,857	(90)
Non-recourse	**549**	554	(5)
Non-controlling interests	**469**	478	(9)
Shareholders' equity			
Common shares	**2,174**	2,169	5
Retained earnings	**638**	634	4
AOCI	**218**	126	92
	7,815	7,818	(3)
Total capital	**7,763**	7,767	(4)

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:

	March 31, 2010	Dec. 31, 2009	Target
Cash flow to interest coverage (times)(1)	**4.6**	4.9	4 to 5 times
Cash flow to debt (%)(1)	**20.4**	20.1	20 to 25 per cent
Debt to invested capital (%)	**54.9**	56.1	55 to 60 per cent

(1) Last 12 months.

For the three months ended March 31, 2010 and 2009, net cash outflows from operating activities, after dividends and capital asset additions, are summarized below:

	3 months ended March 31		
	2010	2009	Increase/ (Decrease)
Cash flow from operating activities	**174**	83	91
Dividends paid	**(59)**	(54)	(5)
Capital asset expenditures	**(126)**	(131)	5
Net cash outflow	**(11)**	(102)	91

For the three months ended March 31, 2010, the increase in the total net cash flows relative to the first quarter of 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.

15. 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 March 31, 2010, TAGP had received $55 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.

CE Gen has entered into contracts with related parties to provide administrative and maintenance services. The total value of these contracts are U.S.$3 million for the year ending Dec. 31, 2010 (Dec. 31, 2009 – U.S.$3 million).

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.

16. 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.

17. 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 Technologies Inc. will have the option to purchase up to a 17 per cent interest in the new operating facility upon completion.

18. 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.

19. 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 March 31, 2010 totalled $341 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 $1.1 billion (Dec. 31, 2009 – $0.7 billion) is not drawn, and is available as of March 31, 2010, subject to customary borrowing conditions.

20. SEGMENTED DISCLOSURES

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

3 months ended March 31, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**712**	**14**	**-**	**726**
Fuel and purchased power	**322**	**-**	**-**	**322**
	390	**14**	**-**	**404**
Operations, maintenance, and administration	**138**	**4**	**18**	**160**
Depreciation and amortization	**99**	**-**	**5**	**104**
Taxes, other than income taxes	**6**	**-**	**-**	**6**
Intersegment cost allocation (recovery)	**1**	**(1)**	**-**	**-**
	244	**3**	**23**	**270**
	146	**11**	**(23)**	**134**
Foreign exchange gain				**3**
Net interest expense *(Note 10)*				**(48)**
Earnings before non-controlling interests and income taxes				**89**

3 months ended March 31, 2009	Generation	Energy Trading	Corporate	Total
Revenues	741	15	-	756
Fuel and purchased power	375	-	-	375
	366	15	-	381
Operations, maintenance, and administration	146	6	22	174
Depreciation and amortization	111	1	5	117
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation (recovery)	8	(8)	-	-
	270	(1)	27	296
	96	16	(27)	85
Foreign exchange gain				1
Net interest expense *(Note 10)*				(33)
Other income *(Note 3)*				7
Earnings before non-controlling interests and income taxes				60

Included above in Generation is $5 million (March 31, 2009 - $2 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind and hydro projects.

The intersegment cost allocation (recovery) decreased for the three months ended March 31, 2010 as a result of support costs previously recovered through the intersegment fee being directly allocated to the Generation segment in 2010.

B. Selected Consolidated Balance Sheets information

As at March 31, 2010	Generation	Energy Trading	Corporate	Total
Goodwill	**401**	**30**	**-**	**431**
Total segment assets	**9,135**	**130**	**442**	**9,707**

As at Dec. 31, 2009				
Goodwill	404	30	-	434
Total segment assets	9,133	148	481	9,762

A change in foreign exchange rates has resulted in a $3 million decrease in goodwill in a self-sustaining foreign operation.

C. Selected Consolidated Cash Flow information

3 months ended March 31, 2010	Generation	Energy Trading	Corporate	Total
Capital expenditures	**119**	**-**	**7**	**126**

3 months ended March 31, 2009				
Capital expenditures	127	-	4	131

D. Depreciation and amortization on Consolidated Statements of Cash Flows

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

3 months ended March 31	2010	2009
Depreciation and amortization expense on Consolidated Statements of Earnings	**104**	117
Depreciation included in fuel and purchased power	**11**	10
Accretion expense included in depreciation and amortization expense	**(5)**	(6)
Depreciation and amortization on Consolidated Statements of Cash Flows	**110**	121

21. CHANGES IN NON-CASH OPERATING WORKING CAPITAL

3 months ended March 31	2010	2009
Source (use):		
Accounts receivable	**100**	180
Prepaid expenses	**(8)**	(10)
Income taxes receivable	**2**	(36)
Inventory	**12**	(5)
Accounts payable and accrued liabilities	**(119)**	(234)
Income taxes payable	**(3)**	(3)
Change in non-cash operating working capital	**(16)**	(108)

22. EMPLOYEE FUTURE BENEFITS

Costs recognized in the period are presented below:

3 months ended March 31, 2010	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**-**	**1**	**-**	**1**
Interest cost	**5**	**1**	**1**	**7**
Actual return on plan assets	**(5)**	**-**	**-**	**(5)**
Actuarial loss	**1**	**-**	**-**	**1**
Amortization of net transition asset	**(2)**	**-**	**-**	**(2)**
Defined benefit (income) expense	**(1)**	**2**	**1**	**2**
Defined contribution option expense of registered pension plan	**6**	**-**	**-**	**6**
Net expense	**5**	**2**	**1**	**8**

3 months ended March 31, 2009	Registered	Supplemental	Other	Total
Current service cost	1	-	-	1
Interest cost	5	1	1	7
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	7	-	-	7
Net expense	7	1	1	9

23. SUBSEQUENT EVENTS

TransAlta has evaluated events subsequent to March 31, 2010 through to April 26, 2010, which represents the date the financial statements were issued.

Centralia Thermal Memorandum of Understanding (“MOU”)

On April 26, 2010, TransAlta announced that it have 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 TransAlta’s shareholders. Details on the results of these discussions will be provided as they become available.

SUPPLEMENTAL INFORMATION

		March 31, 2010	Dec. 31, 2009
Closing market price (TSX) ($)		**22.47**	23.48
Price range for the last 12 months (TSX) ($)	High	**23.98**	25.30
	Low	**18.38**	18.11
Debt to invested capital including non recourse debt (%)		**54.9**	56.1
Debt to invested capital excluding non recourse debt (%)		**51.3**	52.6
Return on shareholders' equity (%)		**7.8**	6.9
Comparable return on shareholders' equity[(1), (2)] (%)		**8.0**	6.9
Return on capital employed[(1)] (%)		**6.4**	5.7
Comparable return on capital employed[(1), (2)] (%)		**6.6**	5.8
Cash dividends per share[(1)] ($)		**1.16**	1.16
Price/earnings ratio[(1)] (times)		**22.5**	26.1
Earnings coverage[(1)] (times)		**2.0**	1.9
Dividend payout ratio based on net earnings[(1)] (%)		**117.0**	129.8
Dividend payout ratio based on comparable earnings[(1), (2)] (%)		**114.2**	129.8
Dividend coverage[(1)] (times)		**2.8**	2.5
Dividend yield[(1)] (%)		**5.2**	4.9
Cash flow to debt[(1)] (%)		**20.4**	20.1
Cash flow to interest coverage[(1)] (times)		**4.6**	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.

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

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

Price/earnings ratio = current period's close price / basic earnings per share

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

Dividend payout ratio = dividends / net earnings or comparable earnings

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 Agreement (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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