TransAlta announces strong fourth quarter results and full year 2010 earnings growth; files year end disclosure documents

- Fourth quarter comparable earnings per share[1] of $0.40; the same as last year
- Fourth quarter fleet availability of 91.4 per cent compared to 87.0 per cent in 2009
- 2010 comparable earnings per share increased nine per cent to $0.98 versus $0.90 in 2009
- Cash flow from operations increased by $231 million to $811 million for the year
- Fully commissioned the 69 megawatt ("MW") Ardenville wind farm and the 54 MW Kent Hills wind farm expansion, ahead of schedule and on budget

CALGARY, Alberta (Feb. 24, 2011) – TransAlta Corporation ("TransAlta") (TSX: TA; NYSE: TAC) today reported fourth quarter 2010 comparable earnings[1] of $88 million ($0.40 per share) versus $84 million ($0.40 per share) in 2009. Reported net earnings applicable to common shares for the fourth quarter were $62 million ($0.28 per common share) compared to $79 million ($0.37 per common share) in 2009.

Comparable results for the quarter were primarily driven by strong availability across the fleet, increased Energy Trading gross margins, and lower depreciation expense. These results were partially offset by weak electricity prices and lost production from the decommissioning of TransAlta's Wabamun 4 unit. Net earnings in the quarter were lower due to asset impairment charges of $54 million related to certain coal and natural gas-fired facilities, partially offset by an increase in mark-to-market gains of $28 million on power hedges.

"Power markets remain challenging and we are doing all we can to offset these conditions through strong operational improvements in terms of availability and cost control. Our Energy Trading business finished the year with a very strong quarter. Additionally, all of our growth projects were completed on time and on budget," said Steve Snyder, TransAlta President and CEO. "The strong close to 2010 provides good momentum for 2011 where we hope to see some market improvement."

Cash flow from operations for the quarter was $309 million versus $246 million in the fourth quarter of 2009. Cash flow was higher in the quarter due to favourable movements in working capital as a result of lower operational expenditures and the timing of related payments.

Fleet availability for the fourth quarter increased to 91.4 per cent compared to 87.0 per cent in the fourth quarter of 2009 due to lower planned and unplanned outages at our Sundance plant and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Genesse 3.

Also in the quarter, TransAlta began commercial operations of its 69 MW, $135 million Ardenville Wind farm on Nov. 10, 2010, followed by commercial operations of its 54 MW, $100 million expansion of the Kent Hills wind farm on Nov. 21, 2010. Both projects began commercial operations on budget and ahead of schedule.

(1) Comparable earnings and comparable earnings per share are not defined under Canadian Generally Accepted Accounting Principles ("Canadian GAAP"). Presenting these measures from period to period helps management and shareholders evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Non-GAAP Measures section of the extended news release for further discussion of these items, including a reconciliation to net earnings.

Results for the twelve months ended December 31, 2010

For the twelve months ended Dec. 31, 2010, comparable earnings were $214 million ($0.98 per share) compared to $181 million ($0.90 per share) for the twelve months ended Dec. 31, 2009. Net earnings applicable to common shares were $218 million ($1.00 per common share) compared to $181 million ($0.90 per common share) in 2009. Comparable earnings increased in 2010 primarily due to increased availability and production, higher generation gross margins, lower operations maintenance and administration costs, and lower depreciation expense. Net earnings were also higher due to the same factors, and as a result of an income tax recovery and mark-to-market gains, largely offset by asset impairment charges.

Cash flow from operations for the twelve months ended Dec. 31, 2010 was $811 million, compared to $580 million for the twelve months ended Dec. 31, 2009. The increase in cash flow from operations in 2010 was driven by higher cash earnings and favourable movements in working capital compared to last year.

Fleet availability for the year was 88.9 per cent compared to 85.1 per cent in 2009. The increase in availability is attributed to lower planned outages at the Keephills plant, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal.

Subsequent Events

TransAlta Board designates new Chair

The board of directors of TransAlta Corporation today announced that Ambassador Gordon D. Giffin has been designated the next Chair of the TransAlta board. Mr. Giffin will succeed Donna Soble Kaufman whose consecutive three-year term limits as Chair expire on April 28, 2011. Mrs. Kaufman has been a director of TransAlta's board since 1989.

Mr. Giffin's appointment is subject to his re-election as a director by TransAlta's shareholders at the annual general meeting of shareholders to be held on April 28, 2011.

TransAlta files year end disclosure documents

TransAlta also announced today it has filed its Annual Information Form, Audited Consolidated Financial Statements and accompanying notes, as well as the Management's Discussion and Analysis ("MD&A"). These documents are available through TransAlta's website at www.transalta.com or through Sedar at www.sedar.com.

TransAlta has also filed its 40-F with the U.S. Securities and Exchange Commission. The form is available through their website at www.sec.gov/edgar.shtml. Paper copies of all documents are available to shareholders free of charge upon request.

TransAlta will hold a conference call and web cast at 9 a.m. MT (11 a.m. ET) today to discuss results. The call will begin with a short address by Steve Snyder, President and CEO, and Brett Gellner, Chief Financial Officer, followed by a question and answer period for investment analysts, investors, and other interested parties. A question and answer period for the media will immediately follow.

Please contact the conference operator five minutes prior to the call, noting "TransAlta Corporation" as the company and "Jess Nieukerk" as moderator.

Dial-in numbers:
For local Toronto participants – 1-416-340-2216
Toll-free North American participants – 1-866-226-1792

A link to the live webcast will be available via TransAlta's website, www.transalta.com, under Web Casts in the Investor Relations section. If you are unable to participate in the call, the instant replay is accessible at 1-800-408-3053 with TransAlta pass code 5257384. A transcript of the broadcast will be posted on TransAlta's website once it becomes available.

Note: If using a hands-free phone, lift the handset and press one to ask a question.

TransAlta is a power generation and wholesale marketing company focused on creating long-term shareholder value. TransAlta maintains a low-to-moderate risk profile by operating a highly contracted portfolio of assets in Canada, the United States and Australia. TransAlta's focus is to efficiently operate our biomass, geothermal, wind, hydro, natural gas and coal facilities in order to provide our customers with a reliable, low-cost source of power. For 100 years, TransAlta has been a responsible operator and a proud contributor to the communities where we work and live. TransAlta is recognized for its leadership on sustainability by the Dow Jones Sustainability North America Index, the FTSE4Good Index and the Jantzi Social Index. TransAlta is Canada's largest investor-owned renewable energy provider.

This news release may contain forward looking statements, including statements regarding the business and anticipated financial performance of TransAlta Corporation. These statements are based on TransAlta Corporation's belief and assumptions based on information available at the time the assumption was made. These statements are subject to a number of risks and uncertainties that may cause actual results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause such differences include legislative or regulatory developments, competition, global capital markets activity, changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where TransAlta Corporation operates.

Note: All financial figures are in Canadian dollars unless noted otherwise.

For more information:

Media Inquiries:

Bob Klager

Director, Public Affairs

Phone: (403) 267-7330

Email: robert_klager@transalta.com

Investor Inquiries:

Jess Nieukerk

Director, Investor Relations

Phone: 1 800-387-3598

Email: investor_relations@transalta.com

BASIS OF PRESENTATION

This news release should be read in conjunction with our 2010 audited consolidated financial statements and 2010 Annual Management's Discussion and Analysis ("MD&A"). In this news release, unless the context otherwise requires, 'we', 'our', 'us', the 'Corporation' and 'TransAlta' refers to TransAlta Corporation and our 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.

RESULTS OF OPERATIONS

Our results of operations are presented on a consolidated basis and by business segment. We have three business segments: Generation, Energy Trading[1] and Corporate. In this news release, the impact of foreign exchange fluctuations on foreign currency denominated transactions and balances is discussed with the relevant items from the Consolidated Statements of Earnings and Consolidated Balance Sheets. While individual line items on the Consolidated Balance Sheets 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.

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Availability (%)	**91.4**	87.0	**88.9**	85.1
Production (GWh)	**12,757**	12,297	**48,614**	45,736
Revenues	**811**	763	**2,819**	2,770
Gross margin[1]	**480**	435	**1,617**	1,542
Operating income[1]	**210**	159	**497**	378
Net earnings applicable to common shares	**62**	79	**218**	181
Net earnings per common share, basic and diluted	**0.28**	0.37	**1.00**	0.90
Comparable earnings per share[1]	**0.40**	0.40	**0.98**	0.90
Comparable EBITDA[1]	**301**	300	**965**	888
Funds from operations[1]	**225**	266	**783**	729
Cash flow from operating activities	**309**	246	**811**	580
Cash flow from operating activities per share[1]	**1.40**	1.17	**3.70**	2.89
Free cash flow (deficiency)[1]	**130**	78	**204**	(117)
Dividends paid per common share	**0.29**	0.29	**1.16**	1.16

	As at Dec. 31, 2010	As at Dec. 31, 2009
Total assets	**9,893**	9,786
Total long-term liabilities	**5,108**	5,548

(1) Our Energy Trading segment was referred to as "Commercial Operations and Development" in 2009.
(2) Gross margin, operating income, comparable earnings per share, comparable Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"), funds from operations, cash flow from operating activities per share, and free cash flow (deficiency) are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this news release for further discussion of these items, including, where applicable, a reconciliation to net earnings and cash flow from operating activities.

AVAILABILITY & PRODUCTION

Availability for the three months ended Dec. 31, 2010 increased compared to the same period in 2009 primarily due to lower planned and unplanned outages at our Sundance plant and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Genesee 3 and higher unplanned outages at Meridian.

Availability for the year ended Dec. 31, 2010 increased primarily due to lower planned outages at our Keephills plant, lower planned and unplanned outages at our Sundance plant, and lower unplanned outages at Centralia Thermal, partially offset by higher planned outages at Centralia Thermal.

Production for the three months ended Dec. 31, 2010 increased 460 gigawatt hours ("GWh") compared to the same period in 2009 due to lower planned and unplanned outages at our Sundance plant, lower unplanned outages at Centralia Thermal, and higher wind and hydro volumes due to the acquisition of Canadian Hydro Developers, Inc. ("Canadian Hydro") and the commissioning of Ardenville and Kent Hills 2, partially offset by the decommissioning of Wabamun, higher economic dispatching at Centralia Thermal, and higher planned outages at Genesee 3.

Production for the year ended Dec. 31, 2010 increased 2,878 GWh as a result of higher wind and hydro volumes primarily due to the acquisition of Canadian Hydro, lower planned and unplanned outages at our Sundance plant, lower unplanned outages at Centralia Thermal, lower planned outages at our Keephills plant, and lower economic dispatching at Centralia Thermal, partially offset by the decommissioning of Wabamun, higher planned outages at Centralia Thermal and Genesee 3, and the expiration of the long-term contract at Saranac.

REPORTED EARNINGS

The primary factors contributing to the change in net earnings applicable to common shares for the three months and year ended Dec. 31, 2010 are presented below:

	3 months ended Dec. 31	Year ended Dec. 31
Net earnings applicable to common shares, 2009	79	181
(Decrease) increase in Generation gross margins	(15)	36
Mark-to-market movements - Generation	46	45
Increase (decrease) in Energy Trading gross margins	14	(6)
(Increase) decrease in OM&A costs	(11)	33
Decrease in depreciation expense	18	16
Asset impairment charges	(73)	(73)
Increase in net interest expense	(6)	(34)
Decrease in other income	-	(8)
Decrease in non-controlling interests	11	18
(Increase) decrease in income tax expense	(1)	14
Other	-	(4)
Net earnings applicable to common shares, 2010	**62**	**218**

Generation gross margins, excluding the impact of mark-to-market movements, decreased for the three months ended Dec. 31, 2010 compared to the same period in 2009 due to unfavourable pricing, the decommissioning of Wabamun, and higher planned outages at Genesee 3, partially offset by higher wind and hydro volumes due to the acquisition of Canadian Hydro and the commissioning of Ardenville and Kent Hills 2, and lower planned and unplanned outages at our Sundance plant.

For the year ended Dec. 31, 2010, Generation gross margins, excluding the impact of mark-to-market movements, increased due to higher wind and hydro volumes primarily as a result of the acquisition of Canadian Hydro, lower planned and unplanned outages at our Sundance plant, and lower planned outages at our Keephills plant, partially offset by unfavourable pricing, the expiration of the long-term contract at Saranac, the decommissioning of Wabamun, and unfavourable foreign exchange rates.

Mark-to-market movements increased for the three months and year ended Dec. 31, 2010 primarily due to the recognition of unrealized gains resulting from certain power hedging relationships being deemed ineffective for accounting purposes.

Energy Trading gross margins for the three months ended Dec. 31, 2010 increased compared to the same period in 2009 due to increased margins in both the eastern and western regions. In the eastern region, increased margins were captured on regional spread strategies. Western region strategies were positively impacted by power positions held in the Alberta market.

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

Operations, Maintenance, and Administration ("OM&A") costs for the three months ended Dec. 31, 2010 increased compared to the same period in 2009 due to higher compensation costs, increased spend related to productivity initiatives, and higher planned maintenance.

For the year ended Dec. 31, 2010, OM&A costs decreased due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by the acquisition of Canadian Hydro.

Depreciation expense for the three months ended Dec. 31, 2010 decreased compared to the same period in 2009 due to the retirement of certain assets during planned maintenance activities in 2009 and a change in the estimated useful lives of certain coal generation facilities and mining assets.

For the year ended Dec. 31, 2010, depreciation expense decreased due to a change in the estimated useful lives of certain coal generation facilities and mining assets, a reduction in the estimated costs associated with decommissioning our Wabamun plant, lower depreciation at Saranac following the expiration of its long-term contract, and favourable foreign exchange rates, partially offset by an increased asset base primarily due to the acquisition of Canadian Hydro.

During the fourth quarter of 2010, we recorded pre-tax asset impairment charges of $89 million related to certain coal and natural gas facilities. Refer to the Asset Impairment Charges section of this news release for further details.

In 2006, we ceased mining activities at the Centralia mine but continued to develop the option to mine the Westfield site, a coal reserve located adjacent to Centralia Thermal. With the successful modifications of the boilers at Centralia Thermal and longer-term contracts in place to supply coal, the project to develop the Westfield site was placed on hold indefinitely and in 2009, the costs that had been capitalized were expensed.

Net interest expense increased for the three months ended Dec. 31, 2010 compared to the same period in 2009 due to higher debt levels, partially offset by higher capitalized interest.

For the year ended Dec. 31, 2010, net interest expense increased due to higher debt levels, partially offset by interest income related to the resolution of certain outstanding tax matters, higher capitalized interest, favourable foreign exchange, and lower interest rates.

In 2009, we settled an outstanding commercial issue that was recorded as a pre-tax gain of $7 million in other income as it related to our previously held Mexican equity investment. We also recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm. The sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

Non-controlling interests decreased for the three months ended Dec. 31, 2010 compared to the same period in 2009 primarily due to an asset impairment charge recorded related to the pending sale of our Meridian facility.

For the year ended Dec. 31, 2010, non-controlling interests decreased due to lower earnings resulting from the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TransAlta Cogeneration, L.P. (“TA Cogen”).

Income tax expense for the three months ended Dec. 31, 2010 was comparable to the same period in 2009.

For the year ended Dec. 31, 2010, income tax expense decreased as a result of the resolution of certain outstanding tax matters, partially offset by higher pre-tax earnings.

CASH FLOW

Cash flow from operating activities for the three months ended Dec. 31, 2010 increased $63 million compared to the same period in 2009 due to favourable movements in working capital primarily as a result of lower operational expenditures and the timing of related payments, partially offset by lower cash earnings.

Cash flow from operating activities for the year ended Dec. 31, 2010 increased $231 million as a result of higher cash earnings and favourable movements in working capital primarily due to the timing of operational payments, favourable inventory movements, and the timing of certain tax related recoveries.

Free cash flow for the three months ended Dec. 31, 2010 increased $52 million compared to the same period in 2009 primarily due to favourable movements in working capital, partially offset by higher sustaining capital expenditures.

For the year ended Dec. 31, 2010, free cash flow increased $321 million primarily due to higher cash earnings, favourable movements in working capital, and lower sustaining capital expenditures.

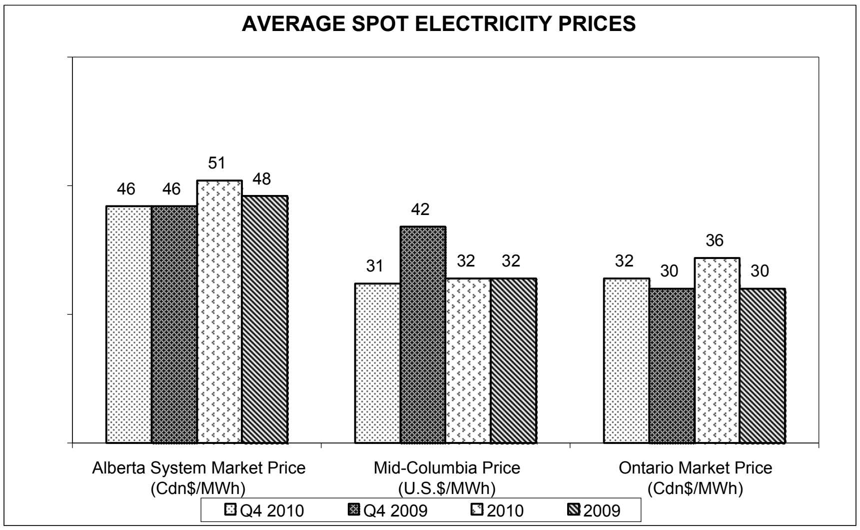
BUSINESS ENVIRONMENT

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 2010 Annual MD&A.

Electricity Prices

Please refer to the Business Environment section of the 2010 Annual MD&A for a full discussion of the spot electricity market and the impact of electricity prices upon our business, as well as our strategy to hedge our risk on changes in those prices.

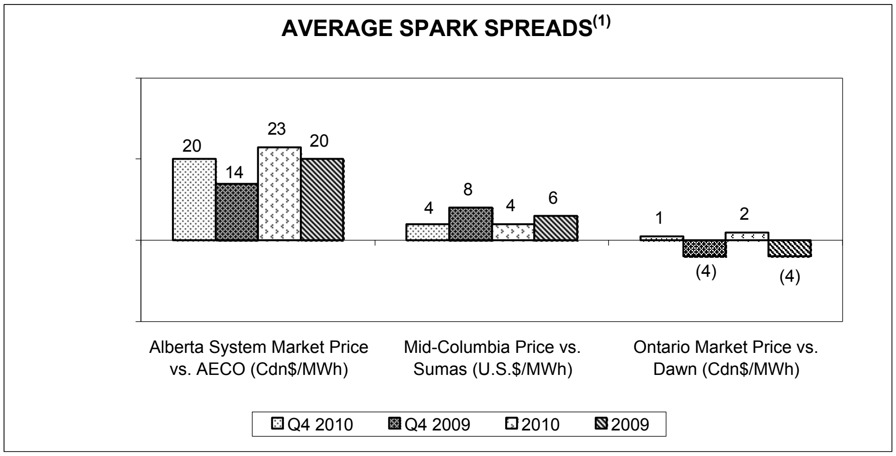
The average spot electricity prices and spark spreads for the three months and year ended Dec. 31, 2010 and 2009 in our three major markets are shown in the following graphs.



For the three months ended Dec. 31, 2010, average spot prices were comparable in Alberta, decreased in the Pacific Northwest, and increased in Ontario compared to the same periods in 2009. In Alberta and Ontario, stronger demand offset lower natural gas prices. In the Pacific Northwest, lower natural gas prices, seasonal demand, and robust supply resulted in lower power prices.

For the year ended Dec. 31, 2010, average spot prices increased in both Alberta and Ontario, and were comparable in the Pacific Northwest compared to the same periods in 2009. In Alberta, demand growth and high prices during the second quarter resulted in a higher annual price. In Ontario, prices increased due to demand recovery. In the Pacific Northwest, marginally higher gas prices were offset by lower weather-related demand.

During the fourth quarter of 2010, our consolidated power portfolio was 95 per cent contracted through the use of Power Purchase Arrangement ("PPAs") and other long-term contracts. We also enter into short-term physical and financial contracts for the remaining volumes, which are primarily for periods of up to five years, with the average price of these contracts in 2010 ranging from $60-$65 per megawatt hour ("MWh") in Alberta, and from U.S.$50-$55 per MWh in the Pacific Northwest.



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

For the three months and year ended Dec. 31, 2010, average spark spreads increased in Alberta and Ontario compared to the same periods in 2009 due to demand growth.

For the three months and year ended Dec. 31, 2010, average spark spreads decreased in the Pacific Northwest compared to the same periods in 2009 due to lower weather-related demand during the third and fourth quarters, as well as increased generation from hydro and wind in the region.

DISCUSSION OF SEGMENTED RESULTS

TransAlta's operating results by segment are presented below:

3 months ended Dec. 31, 2010	Generation	Energy Trading	Corporate	Total
Revenues	787	24	-	811
Fuel and purchased power	331	-	-	331
	456	24	-	480
Operations, maintenance and administration	130	5	18	153
Depreciation and amortization	105	1	5	111
Taxes, other than income taxes	6	-	-	6
Intersegment cost allocation	1	(1)	-	-
	242	5	23	270
	214	19	(23)	210
Foreign exchange gain				6
Asset impairment charges				(89)
Net interest expense				(48)
Earnings before non-controlling interests and income taxes				79

3 months ended Dec. 31, 2009	Generation	Energy Trading	Corporate	Total
Revenues	753	10	-	763
Fuel and purchased power	328	-	-	328
	425	10	-	435
Operations, maintenance and administration	116	6	20	142
Depreciation and amortization	123	2	4	129
Taxes, other than income taxes	5	-	-	5
Intersegment cost allocation	8	(8)	-	-
	252	-	24	276
	173	10	(24)	159
Foreign exchange loss				4
Asset impairment charges				(16)
Net interest expense				(42)
Earnings before non-controlling interests and income taxes				105

Year ended Dec. 31, 2010	**Generation**	**Energy Trading**	**Corporate**	**Total**
Revenues	**2,778**	**41**	**-**	**2,819**
Fuel and purchased power	**1,202**	**-**	**-**	**1,202**
	1,576	**41**	**-**	**1,617**
Operations, maintenance and administration	**549**	**17**	**68**	**634**
Depreciation and amortization	**438**	**2**	**19**	**459**
Taxes, other than income taxes	**27**	**-**	**-**	**27**
Intersegment cost allocation	**5**	**(5)**	**-**	**-**
	1,019	**14**	**87**	**1,120**
	557	**27**	**(87)**	**497**
Foreign exchange gain				**10**
Asset impairment charges				**(89)**
Net interest expense				**(178)**
Earnings before non-controlling interests and income taxes				**240**

Year ended Dec. 31, 2009	Generation	Energy Trading	Corporate	Total
Revenues	2,723	47	-	2,770
Fuel and purchased power	1,228	-	-	1,228
	1,495	47	-	1,542
Operations, maintenance and administration	550	31	86	667
Depreciation and amortization	453	4	18	475
Taxes, other than income taxes	22	-	-	22
Intersegment cost allocation	32	(32)	-	-
	1,057	3	104	1,164
	438	44	(104)	378
Foreign exchange loss				8
Asset impairment charges				(16)
Net interest expense				(144)
Other income				8
Earnings before non-controlling interests and income taxes				234

GENERATION: *Owns and operates hydro, wind, geothermal, biomass, natural gas- and coal-fired facilities, and related mining operations in Canada, the U.S., and Australia. Generation's revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. During the fourth quarter of 2010, we began commercial operations at Ardenville, a 69 megawatt ("MW") wind farm in southern Alberta, and Kent Hills 2, a 54 MW expansion of our wind farm in New Brunswick. At Dec. 31, 2010, Generation had 9,109 MW of gross generating capacity*[1] *in operation (8,676 MW net ownership interest) and 305 MW (net ownership interest) 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 2010 Annual MD&A.*

The results of the Generation segment are as follows:

3 months ended Dec. 31	**2010 Total**	**2010 Per installed MWh**	2009 Total	2009 Per installed MWh
Revenues	**787**	**39.13**	753	37.79
Fuel and purchased power	**331**	**16.46**	328	16.46
Gross margin	**456**	**22.67**	425	21.33
Operations, maintenance and administration	**130**	**6.46**	116	5.82
Depreciation and amortization	**105**	**5.22**	123	6.18
Taxes, other than income taxes	**6**	**0.30**	5	0.25
Intersegment cost allocation	**1**	**0.05**	8	0.40
Operating expenses	**242**	**12.03**	252	12.65
Operating income	**214**	**10.64**	173	8.68
Installed capacity (GWh)	**20,113**		19,928	
Production (GWh)	**12,757**		12,297	
Availability (%)	**91.4**		87.0	

Year ended Dec. 31	**2010 Total**	**2010 Per installed MWh**	2009 Total	2009 Per installed MWh
Revenues	**2,778**	**34.90**	2,723	36.37
Fuel and purchased power	**1,202**	**15.10**	1,228	16.40
Gross margin	**1,576**	**19.80**	1,495	19.97
Operations, maintenance and administration	**549**	**6.90**	550	7.35
Depreciation and amortization	**438**	**5.50**	453	6.05
Taxes, other than income taxes	**27**	**0.34**	22	0.29
Intersegment cost allocation	**5**	**0.06**	32	0.43
Operating expenses	**1,019**	**12.80**	1,057	14.12
Operating income	**557**	**7.00**	438	5.85
Installed capacity (GWh)	**79,591**		74,866	
Production (GWh)	**48,614**		45,736	
Availability (%)	**88.9**		85.1	

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

Production and Gross Margins

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

3 months ended Dec. 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	6,418	7,744	221	97	124	28.54	12.53	16.01
Gas	1,018	1,240	63	19	44	50.81	15.32	35.49
Renewables	705	2,904	45	3	42	15.50	1.03	14.47
Total Western Canada	**8,141**	**11,888**	**329**	**119**	**210**	**27.67**	**10.01**	**17.66**
Gas	946	1,656	111	60	51	67.03	36.23	30.80
Renewables	424	1,459	40	2	38	27.42	1.37	26.05
Total Eastern Canada	**1,370**	**3,115**	**151**	**62**	**89**	**48.48**	**19.90**	**28.58**
Coal	2,442	3,038	248	136	112	81.63	44.77	36.86
Gas	450	1,698	33	13	20	19.43	7.66	11.77
Renewables	354	374	26	1	25	69.52	2.67	66.85
Total International	**3,246**	**5,110**	**307**	**150**	**157**	**60.08**	**29.35**	**30.73**
	12,757	**20,113**	**787**	**331**	**456**	**39.13**	**16.46**	**22.67**

3 months ended Dec. 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	6,571	8,361	241	96	145	28.82	11.48	17.34
Gas	1,052	1,227	67	21	46	54.60	17.11	37.49
Renewables	593	2,517	33	2	31	13.11	0.79	12.32
Total Western Canada	8,216	12,105	341	119	222	28.17	9.83	18.34
Gas	826	1,656	106	53	53	64.01	32.00	32.01
Renewables	302	1,057	28	1	27	26.49	0.95	25.54
Total Eastern Canada	1,128	2,713	134	54	80	49.39	19.90	29.49
Coal	2,172	3,038	217	141	76	71.43	46.41	25.02
Gas	419	1,698	34	14	20	20.02	8.24	11.78
Renewables	362	374	27	-	27	72.19	-	72.19
Total International	2,953	5,110	278	155	123	54.40	30.33	24.07
	12,297	19,928	753	328	425	37.79	16.46	21.33

Year ended Dec. 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	25,025	31,325	813	335	478	25.95	10.69	15.26
Gas	3,981	4,866	232	76	156	47.68	15.62	32.06
Renewables	2,506	11,120	142	10	132	12.77	0.90	11.87
Total Western Canada	**31,512**	**47,311**	**1,187**	**421**	**766**	**25.09**	**8.90**	**16.19**
Gas	3,816	6,570	435	243	192	66.21	36.99	29.22
Renewables	1,330	5,435	126	7	119	23.18	1.29	21.89
Total Eastern Canada	**5,146**	**12,005**	**561**	**250**	**311**	**46.73**	**20.82**	**25.91**
Coal	8,594	12,053	773	470	303	64.13	38.99	25.14
Gas	2,063	6,736	140	56	84	20.78	8.31	12.47
Renewables	1,299	1,486	117	5	112	78.73	3.36	75.37
Total International	**11,956**	**20,275**	**1,030**	**531**	**499**	**50.80**	**26.19**	**24.61**
	48,614	**79,591**	**2,778**	**1,202**	**1,576**	**34.90**	**15.10**	**19.80**

Year ended Dec. 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	24,517	32,833	838	349	489	25.52	10.63	14.89
Gas	4,035	4,744	228	79	149	48.06	16.65	31.41
Renewables	1,891	8,757	116	7	109	13.25	0.80	12.45
Total Western Canada	30,443	46,334	1,182	435	747	25.51	9.39	16.12
Gas	3,377	6,570	388	224	164	59.06	34.09	24.97
Renewables	452	1,686	40	1	39	23.72	0.59	23.13
Total Eastern Canada	3,829	8,256	428	225	203	51.84	27.25	24.59
Coal	7,450	12,053	767	476	291	63.63	39.49	24.14
Gas	2,637	6,736	213	82	131	31.62	12.17	19.45
Renewables	1,377	1,486	133	10	123	89.50	6.73	82.77
Total International	11,464	20,275	1,113	568	545	54.89	28.01	26.88
	45,736	74,865	2,723	1,228	1,495	36.37	16.40	19.97

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 2010 Annual MD&A for further details on our Western Canada operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2010 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2009	8,216	30,443
Lower planned outages at Keephills	-	865
Lower planned outages at Sundance	343	613
Lower unplanned outages at Sundance	225	460
Higher merchant volumes due to Sundance 5 uprate	43	390
Higher wind volumes primarily due to the acquisition of Canadian Hydro	44	344
Higher hydro volumes primarily due to the acquisition of Canadian Hydro	68	270
Higher PPA customer demand	87	140
Decommissioning of Wabamun	(451)	(1,424)
Higher planned outages at Genesee 3	(219)	(219)
Lower production at natural gas-fired facilities	(38)	(153)
Higher unplanned outages at Keephills	(61)	(61)
Higher unplanned outages at Sheerness	(15)	(75)
Other	(101)	(81)
Production, 2010	**8,141**	**31,512**

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

	3 months ended Dec. 31	Year ended Dec. 31
Gross margin, 2009	222	747
Lower planned outages at Keephills	-	36
Lower planned outages at Sundance	13	30
Lower unplanned outages at Sundance	17	25
Higher wind volumes primarily due to the acquisition of Canadian Hydro	11	25
Higher hydro volumes primarily due to the acquisition of Canadian Hydro	3	20
Higher merchant volumes due to Sundance 5 uprate	1	12
Unfavourable pricing	(30)	(72)
Decommissioning of Wabamun	(16)	(42)
Higher planned outages at Genesse 3	(7)	(7)
Higher unplanned outages at Sheerness	-	(5)
Higher unplanned outages at Keephills	(2)	(2)
Other	(2)	(1)
Gross margin, 2010	**210**	**766**

Eastern Canada

Our Eastern Canada assets consist of natural gas, hydro, and wind facilities. Refer to the Discussion of Segmented Results section of our 2010 Annual MD&A for further details on our Eastern Canada operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2010 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2009	1,128	3,829
Higher wind and hydro volumes	127	894
Market conditions at natural gas-fired facilities	113	307
Lower planned outages at natural gas-fired facilities	2	116
Production, 2010	1,370	5,146

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

	3 months ended Dec. 31	Year ended Dec. 31
Gross margin, 2009	80	203
Higher wind and hydro volumes	10	80
Market conditions at natural gas-fired facilities	3	23
Other	(4)	5
Gross margin, 2010	89	311

On Sept. 30, 2009, we entered into a new agreement with the Ontario Power Authority (“OPA”) for our Sarnia regional cogeneration power plant. While the specific terms and conditions of the new agreement are confidential, the OPA has indicated that it is in line with other similar agreements issued by the OPA. The impact of this new agreement with the OPA has been reflected in the gross margin analysis presented above.

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 2010 Annual MD&A for further details on our International operations.

The primary factors contributing to the change in production for the three months and year ended Dec. 31, 2010 are presented below:

	3 months ended Dec. 31 (GWh)	Year ended Dec. 31 (GWh)
Production, 2009	2,953	11,464
Lower unplanned outages at Centralia Thermal	544	958
Economic dispatching at Centralia Thermal	(274)	596
Higher planned outages at Centralia Thermal	-	(410)
Expiration of long-term contract at Saranac	-	(357)
Higher (lower) production at natural gas-fired facilities	32	(179)
Lower production at geothermal facilities	(7)	(100)
Other	(2)	(16)
Production, 2010	**3,246**	**11,956**

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

	3 months ended Dec. 31	Year ended Dec. 31
Gross margin, 2009	123	545
Expiration of long-term contract at Saranac	-	(42)
Unfavourable foreign exchange	(6)	(41)
Lower production at natural gas-fired facilities	-	(6)
Economic dispatching at Centralia Thermal	-	(5)
Higher coal costs	(3)	(5)
Favourable mark-to-market movements	42	37
Favourable pricing primarily related to purchased power	1	18
Lower outages at Centralia Thermal	3	8
Other	(3)	(10)
Gross margin, 2010	**157**	**499**

During the fourth quarter of 2010, unrealized pre-tax gains of $43 million were recorded in earnings due to certain power hedging relationships being deemed ineffective for accounting purposes. These unrealized gains were calculated using current forward prices which will change between now and the time the underlying hedged transactions were expected to occur. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in the period that they settle, the majority of which will occur during the second quarter of 2011. While future reported earnings will be lower, the expected cash flows from these contracts will not change.

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, resulting in lower production and gross margin for year ended Dec. 31, 2010. 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 $10 million for the year ended Dec. 31, 2010.

Operations, Maintenance and Administration Expense

OM&A costs for the three months ended Dec. 31, 2010 increased compared to the same period in 2009 primarily due to higher planned outages at Genesee 3.

For the year ended Dec. 31, 2010, OM&A costs decreased due to lower planned outages, favourable foreign exchange rates, and targeted cost savings, partially offset by information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010 and the acquisition of Canadian Hydro.

Depreciation Expense

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

	3 months ended Dec. 31	Year ended Dec. 31
Depreciation and amortization expense, 2009	123	453
Change in useful lives	(7)	(26)
Reduction in decommissioning costs at Wabamun	-	(14)
Expiration of long-term contract at Saranac	-	(13)
Favourable foreign exchange	(1)	(13)
Asset retirements	(11)	(4)
Increased asset base primarily due to the acquisition of Canadian Hydro	1	53
Other	-	2
Depreciation and amortization expense, 2010	**105**	**438**

During the fourth quarter of 2010, management updated the preliminary purchase price allocation related to our acquisition of Canadian Hydro to better reflect the value of the underlying assets and liabilities acquired. As a result, a $114 million adjustment was made to depreciable assets, producing a $4 million decrease in depreciation expense. The adjustment to depreciable assets was offset by adjustments to goodwill and future income taxes.

ASSET IMPAIRMENT CHARGES

During the fourth quarter of 2010, we completed our annual comprehensive impairment assessment based on fair value estimates derived from our long-range forecast and market values evidenced in the marketplace. As a result, we recorded pre-tax asset impairment charges of $89 million ($79 million after deducting the amount that is attributable to the non-controlling interest) on certain Generation assets, comprised of a $65 million charge against our natural gas fleet and a $24 million charge against our coal fleet. The natural gas fleet impairment reflects lower forecast pricing at one of our merchant facilities and the pending sale of our 50 per cent interest in our Meridian facility, which had no impact to consolidated earnings as the impairment was attributable to the non-controlling interest. The coal fleet impairment relates to Units 1 and 2 at our Sundance facility and primarily reflects our shift in 2010 to managing our coal-fired generation facilities on a unit pair basis, resulting in the impairment assessment now being performed on a unit pair basis.

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 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 and transmission capacity. Energy Trading is also responsible for recommending portfolio optimization decisions. The results of these activities are included in the Generation segment.

For a more in-depth discussion of our Energy Trading activities, refer to the Discussion of Segmented Results section of our 2010 Annual MD&A.

The results of the Energy Trading segment are as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Gross margin	**24**	10	**41**	47
Operations, maintenance and administration	**5**	6	**17**	31
Depreciation and amortization	**1**	2	**2**	4
Intersegment cost allocation	**(1)**	(8)	**(5)**	(32)
Operating expenses	**5**	-	**14**	3
Operating income	**19**	10	**27**	44

Energy Trading gross margins for the three months ended Dec. 31, 2010 increased compared to the same period in 2009 due to increased margins in both the eastern and western regions. In the eastern region, increased margins were captured on regional spread strategies. Western region strategies were positively impacted by power positions held in the Alberta market.

For the year ended Dec. 31, 2010, Energy Trading gross margins decreased primarily due to reduced margins resulting from reduced market demand and narrowing inter-season spreads in the western region.

OM&A costs and the inter-segment fee for the three months and year ended Dec. 31, 2010 decreased compared to the same periods in 2009 as a result of support costs previously borne by the Energy Trading segment and recovered through the intersegment fee being directly charged to the Generation segment in 2010.

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

The expenses incurred by the Corporate segment are as follows:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Operations, maintenance and administration	**18**	20	**68**	86
Depreciation and amortization	**5**	4	**19**	18
Operating expenses	**23**	24	**87**	104

OM&A costs for the year ended Dec. 31, 2010 decreased compared to the same period in 2009 primarily due to information system costs directly attributable to our operations previously borne by the Corporate segment now being directly charged to the Generation segment in 2010.

NET INTEREST EXPENSE

The components of net interest expense are shown below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Interest on debt	**62**	51	**243**	183
Capitalized interest	**(13)**	(9)	**(48)**	(36)
Interest income from the resolution of certain outstanding tax matters	**-**	-	**(14)**	-
Interest income	**(1)**	-	**(3)**	(6)
Other	**-**	-	**-**	3
Net interest expense	**48**	42	**178**	144

The change in net interest expense for the three months and year ended Dec. 31, 2010, compared to the same periods in 2009 is shown below:

	3 months ended Dec. 31	Year ended Dec. 31
Net interest expense, 2009	42	144
Higher debt levels	13	78
(Higher) lower interest income	(1)	3
Interest income from the resolution of certain outstanding tax matters	-	(14)
Higher capitalized interest	(4)	(12)
Favourable foreign exchange	(1)	(11)
Lower interest rates	(1)	(10)
Net interest expense, 2010	**48**	**178**

OTHER INCOME

In 2009, we settled an outstanding commercial issue that was recorded as a pre-tax gain of $7 million in other income as it related to our previously held Mexican equity investment. We also recorded a pre-tax gain of $1 million on the sale of a 17 per cent interest in our Kent Hills wind farm. The pre-tax gain recorded related to the sale of a 17 per cent interest in our Kent Hills 2 wind farm expansion project in 2010 did not have a significant impact on net earnings.

NON-CONTROLLING INTERESTS

The earnings attributable to non-controlling interests for the three months ended Dec. 31, 2010 decreased $11 million primarily due to an asset impairment charge recorded related to the pending sale of our Meridian facility.

For the year ended Dec. 31, 2010, non-controlling interests decreased $18 million due to lower earnings at CE Generation, LLC as a result of the expiration of the long-term contract at our Saranac facility and an asset impairment charge related to the pending sale of our Meridian facility, partially offset by higher earnings at TA Cogen.

INCOME TAXES

A reconciliation of income tax expense and effective tax rates is presented below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Earnings before income taxes	**79**	94	**220**	196
Asset impairment charges	**79**	-	**79**	16
Unrealized gains related to ineffectiveness in certain power hedging relationships	**(43)**	-	**(43)**	-
Settlement of commercial issue	**-**	-	**-**	(7)
Change in life of Centralia parts	**-**	-	**-**	2
Comparable earnings[1] before income taxes	**115**	94	**256**	207
Income tax expense	**16**	15	**1**	15
Income tax recovery related to asset impairment charges	**25**	**-**	**25**	**6**
Income tax expense related to ineffectiveness in certain power hedging relationships	**(15)**	**-**	**(15)**	**-**
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**30**	-
Income tax expense on settlement of commercial issue	**-**	-	**-**	(1)
Income tax recovery on life of Centralia parts	**-**	-	**-**	1
Income tax recovery related to change in future tax rates	**-**	5	**-**	5
Income tax expense excluding non-comparable items	**26**	20	**41**	26
Effective tax rate on comparable earnings before income taxes (%)	**23**	21	**16**	13

Income tax expense excluding non-comparable items increased for the three months and year ended Dec. 31, 2010 compared to the same periods in 2009 as a result of higher comparable earnings before income taxes.

The effective tax rate increased for the three months and year ended Dec. 31, 2010 compared to the same periods in 2009 primarily due to certain deductions that do not fluctuate with earnings and a change in the mix of jurisdictions where pre-tax income is earned.

(1) Comparable earnings are not defined under Canadian GAAP. Refer to the Non-GAAP Measures section of this news release for further discussion of this item, as well as a reconciliation to net earnings.

STATEMENTS OF CASH FLOWS

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

3 months ended Dec. 31	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of period	**80**	86	
Provided by (used in):			
Operating activities	**309**	246	Favourable changes in working capital of $104 million due to lower operational expenditures and the timing of related payments, partially offset by lower cash earnings of $41 million.
Investing activities	**(197)**	(1,036)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million in 2009 and a decrease in 2010 capital spending of $26 million, partially offset by a decrease in collateral received from counterparties of $21 million.
Financing activities	**(130)**	787	Proceeds of $919 million from the issuance of long-term debt and $398 million from the issuance of common shares in 2009, partially offset by proceeds of $291 million from the issuance of preferred shares in 2010 and a net decrease in the repayment of debt of $89 million.
Translation of foreign currency cash	**(4)**	(1)	
Cash and cash equivalents, end of period	**58**	82	

Year ended Dec. 31	**2010**	2009	Primary factors explaining change
Cash and cash equivalents, beginning of year	**82**	50	
Provided by (used in):			
Operating activities	**811**	580	Higher cash earnings of $54 million and favourable changes in working capital of $177 million due to the timing of operational payments, favourable inventory movements, and the timing of certain tax-related recoveries.
Investing activities	**(720)**	(1,598)	Acquisition of Canadian Hydro, net of cash acquired, for $766 million in 2009 and a decrease in 2010 capital spending of $114 million, partially offset by a decrease in collateral received from counterparties of $40 million.
Financing activities	**(113)**	1,053	Increase of $818 million in proceeds from the issuance of long-term debt and $397 million from the issuance of common shares in 2009, and a net increase in the repayment of debt of $255 million, partially offset by proceeds of $291 million from the issuance of preferred shares in 2010.
Translation of foreign currency cash	**(2)**	(3)	
Cash and cash equivalents, end of year	**58**	82	

LIQUIDITY AND CAPITAL RESOURCES

Share Capital

At Dec. 31, 2010, we had 220.3 million (2009 – 218.4 million) common shares issued and outstanding. During the three months ended Dec. 31, 2010, 0.8 million (2009 – 20.8 million) common shares were issued for $23 million (2009 – $408 million), of which $19 million (2009 – nil) was issued under the terms of the dividend reinvestment and share purchase ("DRASP") plan. During the year ended Dec. 31, 2010, 1.9 million (2009 – 20.8 million) common shares were issued for $42 million (2009 – $408 million), of which $37 million (2009 – nil) was issued under the terms of the DRASP plan.

During the three months ended and as at Dec. 31, 2010, 12.0 million (2009 – nil) first preferred shares were issued for $239 million (2009 – nil).

We employ a variety of stock-based compensation to align employee and corporate objectives. At Dec. 31, 2010, we had 2.2 million outstanding employee stock options (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 Dec. 31, 2010, a nominal number of options expired, or were exercised or cancelled (2009 – nil). During the year ended Dec. 31, 2010, 0.2 million options expired, or were exercised or cancelled (2009 – 0.2 million).

2011 OUTLOOK

In 2011, we anticipate modest comparable EPS growth based upon the factors that are discussed below.

Business Environment

Power Prices

In 2011, power prices are expected to remain at 2010 levels due to the influence of low natural gas prices. In the Alberta market, the longer-term fundamentals of the market remain positive and the recovery of the oil sands is expected to drive load growth. In the Pacific Northwest, the recovery of natural gas prices is the main driver behind any recovery of power prices. Natural gas prices are expected to remain low until 2012.

Environmental Legislation

The state of development of environmental regulations in both Canada and the U.S. remains fluid. Canada has expressed its plan to coordinate the timing and structure of its greenhouse gas regulatory framework with the U.S., although coal-fired power is being addressed separately and earlier. 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

The economic environment has shown signs of improvement in 2010 and we expect this trend to continue through 2011 at a slow to moderate pace.

We had no counterparty losses in 2010, and we continue to monitor counterparty credit risk and act in accordance with our established risk management policies. We do not anticipate any material change to our existing credit practices and continue to deal primarily with investment grade counterparties.

Operations

Capacity, Production, and Availability

Generating capacity is expected to increase in 2011 due to the start of commercial operations at Keephills 3 and Bone Creek. Overall production is expected to increase in 2011 due to the start of commercial operations at Keephills 3 and Bone Creek, lower planned and unplanned outages, and higher customer demand. Overall fleet availability is expected to be approximately 89 to 90 per cent in 2011 due to lower planned and unplanned outages.

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 65 per cent in the fourth year. As at the end of 2010, approximately 88 per cent of our 2011 capacity was contracted. The average price of our short-term physical and financial contracts in 2011 ranges from $65-$70 per MWh in Alberta, and from U.S.$55-$60 per MWh in the Pacific Northwest.

Fuel Costs

Mining coal in Alberta is subject to cost increases due to greater overburden removal, inflation, capital investments, and commodity prices. Seasonal variations in coal costs at our Alberta mines are minimized through the application of standard costing. Coal costs for 2011, on a standard cost basis, are expected to be consistent with 2010.

Fuel at Centralia Thermal is purchased from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel for 2011 is expected to be consistent with 2010.

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

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

Operations, Maintenance, and Administration Costs

OM&A costs for 2011 are expected to be lower as a result of certain planned maintenance costs that had been expensed under Canadian GAAP being capitalized under International Financial Reporting Standards ("IFRS") in 2011, and lower OM&A costs related to our Poplar Creek base plant. In 2011, we will no longer operate the Poplar Creek base plant resulting in reduced OM&A expenditures and associated cost recoveries. The impact of no longer operating the Poplar Creek base plant is not expected to be significant to net earnings.

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 2011 objective is for Energy Trading to contribute between $45 million and $65 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 revenues.

Net Interest Expense

Net interest expense for 2011 is expected to be higher than 2010 mainly due to higher debt balances, higher variable interest rates, lower capitalized interest, and lower interest income. 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 in the future. To mitigate this liquidity risk, we expect to maintain $2.0 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 this 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 cash flows as they are generally settled at the contracted prices.

Income Taxes

The effective tax rate for 2011 is expected to be approximately 17 to 22 per cent.

Capital Expenditures

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

Growth Capital Expenditures

In 2010, we spent a total of $470 million on growth capital expenditures, net of any joint venture contributions received. In 2010, we successfully commenced commercial operations at Summerview 2, Ardenville, and Kent Hills 2. We have five additional significant growth capital projects that are currently in progress with targeted completion dates between Q1 2011 and Q4 2012.

A summary of the significant projects that are in progress is outlined below:

	Total Project		2010	2011	Target	
Project	**Estimated spend**	**Spend to date(1)**	**Actual spend(1)**	**Estimated spend**	**completion date**	**Details**
Keephills 3	988	928	221	50 - 60	Q2 2011	A 450 MW (225 MW net ownership interest) supercritical coal-fired plant and associated mine capital in a partnership with Capital Power
Keephills Unit 1 uprate	34	4	3	10 - 20	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Keephills Unit 2 uprate	34	6	5	20 - 30	Q4 2012	A 23 MW efficiency uprate at our Keephills plant
Bone Creek	48	54	50	-	Q1 2011	A 19 MW hydro facility in British Columbia
Sundance Unit 3 uprate	27	3	3	10 - 15	Q4 2012	A 15 MW efficiency uprate at our Sundance plant
Total growth expenditures	**1,131**	**995**	**282**	**90 - 125**		

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

The total estimated spend for Bone Creek is less than the amount incurred to date due to the timing of project spend and estimated recoveries in 2011.

(1) Represents amounts spent as of Dec. 31, 2010. In 2010, we also spent a combined total of $188 million on Summerview 2, Ardenville, and Kent Hills 2.

Sustaining Capital Expenditures

Certain costs related to planned maintenance that have been expensed under Canadian GAAP in 2010 will be capitalized under IFRS in 2011. Our estimate for total sustaining capital expenditures in 2011, net of any contributions received, is allocated among the following:

Category	Description	Spend in 2010	Expected cost
Routine capital	Expenditures to maintain our existing generating capacity	147	120 - 135
Productivity capital	Projects to improve power production efficiency	9	10 - 20
Mining equipment and land purchases	Expenditures related to mining equipment and land purchases	25	25 - 30
Planned maintenance	Regularly scheduled major maintenance	127	180 - 210
Total sustaining expenditures		**308**	**335 - 395**

Details of the 2011 planned maintenance program are outlined as follows:

	Coal	Gas and Renewables	Expected cost
Capitalized	105 - 130	75 - 80	**180 - 210**
Expensed	-	0 - 5	**0 - 5**
	105 - 130	75 - 85	**175 - 200**

	Coal	Gas and Renewables	Total
GWh lost	1,480 - 1,490	630 - 640	**2,110 - 2,130**

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities, existing bank 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.

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 applicable to common shares below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Revenues	**811**	763	**2,819**	2,770
Fuel and purchased power	**331**	328	**1,202**	1,228
Gross margin	**480**	435	**1,617**	1,542
Operations, maintenance, and administration	**153**	142	**634**	667
Depreciation and amortization	**111**	129	**459**	475
Taxes, other than income taxes	**6**	5	**27**	22
Operating expenses	**270**	276	**1,120**	1,164
Operating income	**210**	159	**497**	378
Foreign exchange gain	**6**	4	**10**	8
Asset impairment charges	**(89)**	(16)	**(89)**	(16)
Net interest expense	**(48)**	(42)	**(178)**	(144)
Other income	**-**	**-**	**-**	8
Earnings before non-controlling interests and income taxes	**79**	105	**240**	234
Non-controlling interests	**-**	11	**20**	38
Earnings before income taxes	**79**	94	**220**	196
Income tax expense	**16**	15	**1**	15
Net earnings	**63**	79	**219**	181
Preferred share dividends	**1**	-	**1**	-
Net earnings applicable to common shares	**62**	79	**218**	181

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 2010, we excluded asset impairment charges, as well as unrealized gains related to certain power hedging relationships deemed ineffective for accounting purposes, as these transactions are unusual in nature and have not historically been a normal occurrence in the course of operating our business. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in comparable earnings in the period that they settle, the majority of which will settle during the second quarter of 2011. In addition, we excluded the impact of an income tax recovery related to the resolution of certain outstanding tax matters as they do not relate to the earnings in the period in which they have been reported.

In calculating comparable earnings for 2009, we have excluded asset impairment charges, the impact of a future tax rate change, and 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 the conversion of Centralia to consuming solely third-party supplied coal.

Earnings on a comparable basis are reconciled to net earnings applicable to common shares below:

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Net earnings applicable to common shares	**62**	79	**218**	181
Asset impairment charges, net of tax	**54**	10	**54**	10
Unrealized gains related to ineffectiveness in certain power hedging relationships, net of tax	**(28)**	-	**(28)**	-
Income tax recovery related to the resolution of certain outstanding tax matters	**-**	-	**(30)**	-
Settlement of commercial issue, net of tax	**-**	-	**-**	(6)
Change in life of Centralia parts, net of tax	**-**	-	**-**	1
Tax rate change	**-**	(5)	**-**	(5)
Earnings on a comparable basis	**88**	84	**214**	181
Weighted average number of common shares outstanding in the period	**220**	211	**219**	201
Earnings on a comparable basis per share	**0.40**	0.40	**0.98**	0.90

Comparable EBITDA

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Operating income	**210**	159	**497**	378
Asset retirement obligation accretion per the Consolidated Statements of Cash Flows	**6**	7	**21**	24
Depreciation and amortization per the Consolidated Statements of Cash Flows(1)	**128**	134	**490**	493
EBITDA	**344**	300	**1,008**	895
Unrealized gains related to ineffectiveness in certain power hedging relationships, pre-tax	**(43)**	-	**(43)**	-
Settlement of commercial issue, pre-tax	**-**	-	**-**	(7)
Comparable EBITDA	**301**	300	**965**	888

Funds from Operations and Cash Flow from Operating Activities per Share

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Funds from operations	**225**	266	**783**	729
Change in non-cash operating working capital balances	**84**	(20)	**28**	(149)
Cash flow from operating activities	**309**	246	**811**	580
Weighted average number of common shares outstanding in the period	**220**	211	**219**	201
Cash flow from operating activities per share	**1.40**	1.17	**3.70**	2.89

(1) To calculate comparable EBITDA, we use depreciation and amortization per the Consolidated Statements of Cash Flows because it takes into account depreciation related to mine assets, which is included in cost of sales on the Consolidated Statements of Earnings.

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 preferred share or common share dividends, or repurchase common shares.

Sustaining capital expenditures for the three months ended Dec. 31, 2010, represents total additions to PP&E per the Consolidated Statements of Cash Flows less $91 million ($86 million net of joint venture contributions) that we have invested in growth projects. For the same period in 2009, we invested $136 million ($132 million net of joint venture contributions) in growth projects. For the year ended Dec. 31, 2010 and 2009, we invested $482 million ($470 million net of joint venture contributions) and $524 million ($510 million net of joint venture contributions), respectively, in growth projects.

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

	3 months ended Dec. 31		Year ended Dec. 31	
	2010	2009	**2010**	2009
Cash flow from operating activities	**309**	246	**811**	580
Add (deduct):				
Sustaining capital expenditures	**(106)**	(87)	**(308)**	(380)
Cash dividends paid on common shares	**(47)**	(57)	**(216)**	(226)
Distributions paid to subsidiaries' non-controlling interests	**(18)**	(18)	**(62)**	(58)
Non-recourse debt repayments[(1)]	**(8)**	(6)	**(21)**	(25)
Other income	**-**	-	**-**	(8)
Free cash flow (deficiency)	**130**	78	**204**	(117)

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

SELECTED QUARTERLY INFORMATION

	Q1 2010	Q2 2010	Q3 2010	**Q4 2010**
Revenues	726	582	700	**811**
Net earnings applicable to common shares	67	51	38	**62**
Basic and diluted earnings per common share	0.31	0.23	0.17	**0.28**
Comparable earnings per common share	0.31	0.10	0.17	**0.40**

	Q1 2009	Q2 2009	Q3 2009	Q4 2009
Revenues	756	585	666	763
Net earnings (loss) applicable to common shares	42	(6)	66	79
Basic and diluted earnings (loss) per common share	0.21	(0.03)	0.34	0.37
Comparable earnings (loss) per common share	0.18	(0.03)	0.34	0.40

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

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

FORWARD LOOKING STATEMENTS

This news release, 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 that projected.

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

Factors that may adversely impact our forward looking statements include risks relating to: (i) fluctuations in market prices and availability of fuel supplies required to generate electricity and in the price of electricity; (ii) the regulatory and political environments in the jurisdictions in which we operate; (iii) environmental requirements and changes in, or liabilities under, these requirements; (iv) changes in general economic conditions including interest rates; (v) operational risks involving our facilities, including unplanned outages at such facilities; (vi) disruptions in the transmission and distribution of electricity; (vii) effects of weather; (viii) disruptions in the source of fuels, water, wind, or biomass required to operate our facilities; (ix) natural disasters; (x) equipment failure; (xi) 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 2010 Annual MD&A and under the heading "Risk Factors" in our 2010 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 Dec. 31		Year ended Dec. 31	
Unaudited	**2010**	2009	**2010**	2009
Revenues	**811**	763	**2,819**	2,770
Fuel and purchased power	**331**	328	**1,202**	1,228
	480	435	**1,617**	1,542
Operations, maintenance, and administration	**153**	142	**634**	667
Depreciation and amortization	**111**	129	**459**	475
Taxes, other than income taxes	**6**	5	**27**	22
	270	276	**1,120**	1,164
	210	159	**497**	378
Foreign exchange gain	**6**	4	**10**	8
Asset impairment charges	**(89)**	(16)	**(89)**	(16)
Net interest expense	**(48)**	(42)	**(178)**	(144)
Other income	**-**	-	**-**	8
Earnings before non-controlling interests and income taxes	**79**	105	**240**	234
Non-controlling interests	**-**	11	**20**	38
Earnings before income taxes	**79**	94	**220**	196
Income tax expense	**16**	15	**1**	15
Net earnings	**63**	79	**219**	181
Preferred share dividends	**1**	-	**1**	-
Net earnings applicable to common shares	**62**	79	**218**	181
Retained earnings				
Opening balance	**600**	618	**634**	688
Common share dividends	**(129)**	(63)	**(319)**	(235)
Closing balance	**533**	634	**533**	634
Weighted average number of common shares outstanding in the period	**220**	211	**219**	201
Net earnings per common share, basic and diluted	**0.28**	0.37	**1.00**	0.90

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

Unaudited	Dec. 31, 2010	Dec. 31, 2009[(1)]
Cash and cash equivalents	**58**	82
Accounts receivable	**428**	421
Collateral paid	**27**	27
Prepaid expenses	**10**	18
Risk management assets	**265**	144
Income taxes receivable	**19**	39
Inventory	**53**	90
	860	821
Long-term receivable	**-**	49
Property, plant, and equipment		
Cost	**11,706**	11,701
Accumulated depreciation	**(4,129)**	(4,142)
	7,577	7,559
Assets held for sale	**60**	-
Goodwill	**517**	434
Intangible assets	**304**	344
Future income tax assets	**240**	234
Risk management assets	**208**	224
Other assets	**127**	121
Total assets	**9,893**	9,786
Short-term debt	**1**	-
Accounts payable and accrued liabilities	**503**	521
Collateral received	**126**	86
Risk management liabilities	**35**	45
Income taxes payable	**8**	10
Future income tax liabilities	**77**	45
Dividends payable	**130**	61
Current portion of long-term debt - recourse	**235**	7
Current portion of long-term debt - non-recourse	**20**	24
Current portion of asset retirement obligation	**38**	32
	1,173	831
Long-term debt - recourse	**3,450**	3,857
Long-term debt - non-recourse	**529**	554
Asset retirement obligation	**204**	250
Liabilities held for sale	**3**	-
Deferred credits and other long-term liabilities	**169**	147
Future income tax liabilities	**630**	662
Risk management liabilities	**123**	78
Non-controlling interests	**435**	478
Shareholders' equity		
Common shares	**2,211**	2,169
Preferred shares	**293**	-
Retained earnings	**533**	634
Accumulated other comprehensive income	**140**	126
Total shareholders' equity	**3,177**	2,929
Total liabilities and shareholders' equity	**9,893**	9,786

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

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(in millions of Canadian dollars)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2010**	2009	**2010**	2009
Net earnings	**63**	79	**219**	181
Other comprehensive (loss) income				
(Losses) on translating net assets of self-sustaining foreign operations	**(38)**	(51)	**(60)**	(209)
Gains on financial instruments designated as hedges of self-sustaining foreign operations, net of tax(1)	**23**	37	**33**	140
(Losses) gains on derivatives designated as cash flow hedges, net of tax(2)	**(75)**	55	**164**	280
Reclassification of (gains) losses on derivatives designated as cash flow hedges to Consolidated Balance Sheets, net of tax(3)	**-**	(3)	**8**	(11)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(4)	**(46)**	(40)	**(129)**	(135)
Reclassification of gains on translation of self-sustaining foreign operations to net earnings, net of tax(5)	**(2)**	-	**(2)**	-
Other comprehensive (loss) income	**(138)**	(2)	**14**	65
Comprehensive (loss) income	**(75)**	77	**233**	246

(1) Net of income tax expense of 4 and 6 for the three months and year ended Dec. 31, 2010 (2009 - 5 expense and 26 expense), respectively.

(2) Net of income tax recovery of 37 and expense of 87 for the three months and year ended Dec. 31, 2010 (2009 - 24 expense and 120 expense), respectively.

(3) Net of income tax expense of nil and 3 for the three months and year ended Dec. 31, 2010 (2009 - 1 recovery and 4 recovery), respectively.

(4) Net of income tax expense of 22 and 65 for the three months and year ended Dec. 31, 2010 (2009 - 17 recovery and 69 recovery), respectively.

(5) Net of income tax expense of 3 for the three months and year ended Dec. 31, 2010, respectively.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	3 months ended Dec. 31		Year ended Dec. 31	
Unaudited	**2010**	2009	**2010**	2009
Operating activities				
Net earnings	**63**	79	**219**	181
Depreciation and amortization	**128**	134	**490**	493
Gain on sale of equipment	**(3)**	-	**(4)**	-
Non-controlling interests	**-**	11	**20**	38
Asset retirement obligation accretion	**6**	7	**21**	24
Asset retirement costs settled	**(10)**	(8)	**(37)**	(35)
Future income taxes	**9**	21	**28**	21
Unrealized (gain) loss from risk management activities	**(49)**	3	**(47)**	2
Unrealized foreign exchange (gain) loss	**(5)**	4	**(5)**	(11)
Asset impairment charges	**89**	16	**89**	16
Other non-cash items	**(3)**	(1)	**9**	-
	225	266	**783**	729
Change in non-cash operating working capital balances	**84**	(20)	**28**	(149)
Cash flow from operating activities	**309**	246	**811**	580
Investing activities				
Acquisition of Canadian Hydro Developers, Inc., net of cash acquired	**-**	(766)	**-**	(766)
Additions to property, plant, and equipment	**(197)**	(223)	**(790)**	(904)
Proceeds on sale of property, plant, and equipment	**3**	2	**6**	7
Proceeds on sale of minority interest in Kent Hills	**15**	-	**15**	29
Resolution of certain tax matters	**17**	(41)	**29**	(41)
Restricted cash	**7**	1	**-**	-
Realized losses on financial instruments	**(7)**	-	**(29)**	(16)
Net (decrease) increase in collateral received from counterparties	**(39)**	(18)	**47**	87
Net decrease (increase) in collateral paid to counterparties	**4**	(2)	**(2)**	7
Settlement of adjustments on sale of Mexican equity investment	**-**	-	**-**	(7)
Other	**-**	11	**4**	6
Cash flow used in investing activities	**(197)**	(1,036)	**(720)**	(1,598)
Financing activities				
Net (decrease) increase in borrowings under credit facilities	**(356)**	320	**(400)**	620
Repayment of long-term debt	**(11)**	(776)	**(31)**	(796)
Issuance of long-term debt	**-**	919	**301**	1,119
Dividends paid on common shares	**(47)**	(57)	**(216)**	(226)
Net proceeds on issuance of common shares	**-**	398	**1**	398
Net proceeds on issuance of preferred shares	**291**	-	**291**	-
Realized gains on financial instruments	**11**	-	**3**	-
Distributions paid to subsidiaries' non-controlling interests	**(18)**	(18)	**(62)**	(58)
Other	**-**	1	**-**	(4)
Cash flow (used in) from financing activities	**(130)**	787	**(113)**	1,053
Cash flow (used in) from operating, investing, and financing activities	**(18)**	(3)	**(22)**	35
Effect of translation on foreign currency cash	**(4)**	(1)	**(2)**	(3)
(Decrease) increase in cash and cash equivalents	**(22)**	(4)	**(24)**	32
Cash and cash equivalents, beginning of year	**80**	86	**82**	50
Cash and cash equivalents, end of year	**58**	82	**58**	82
Cash taxes (recovered) paid	**(28)**	8	**(49)**	43
Cash interest paid	**57**	71	**153**	149

SUPPLEMENTAL INFORMATION

		Dec. 31, 2010	Dec. 31, 2009
Closing market price (TSX) ($)		**21.15**	23.48
Price range for the last 12 months (TSX) ($)	High	**23.98**	25.30
	Low	**19.61**	18.11
Debt to invested capital including non recourse debt (%)		**53.6**	56.1
Debt to invested capital excluding non recourse debt (%)		**50.1**	52.6
Return on common shareholders' equity (%)		**7.9**	6.9
Comparable return on common shareholders' equity(1), (2) (%)		**7.7**	6.9
Return on capital employed(1) (%)		**5.5**	5.7
Comparable return on capital employed(1), (2) (%)		**6.1**	5.8
Cash dividends per share(1) ($)		**1.16**	1.16
Price/earnings ratio(1) (times)		**21.2**	26.1
Earnings coverage(1) (times)		**1.8**	1.9
Dividend payout ratio based on net earnings(1) (%)		**146.3**	129.8
Dividend payout ratio based on comparable earnings(1), (2) (%)		**149.1**	129.8
Dividend coverage(1) (times)		**3.8**	2.6
Dividend yield(1) (%)		**5.5**	4.9
Cash flow to debt(1) (%)		**18.3**	20.5
Cash flow to interest coverage(1) (times)		**4.3**	4.9

(1) Last 12 months

(2) These ratios incorporate items that are not defined under Canadian GAAP. None of these measurements are used to enhance the Corporation's reported financial performance or position. These ratios are useful complementary measurements for assessing the Corporation's financial performance, efficiency, and liquidity and are common in the reports of other companies but may differ by definition and application. For a reconciliation of the Non-GAAP measure used in this calculation, refer to the Non-GAAP Measures section of this news release.

RATIO FORMULAS

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

Return on common shareholders' equity = net earnings applicable to common shares or earnings on a comparable basis / average common 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 applicable to common shares + income taxes + net interest expense) / (interest on debt – interest income)

Dividend payout ratio = common share dividends / net earnings applicable to common shares or earnings on a comparable basis

Dividend coverage = cash flow from operating activities / cash dividends paid on common shares

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 – average cash and cash equivalents)

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

GLOSSARY OF KEY TERMS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TransAlta Corporation
Box 1900, Station “M”
110 - 12th Avenue S.W.
Calgary, Alberta Canada T2P 2M1
Phone
403.267.7110

Website
www.transalta.com

CIBC Mellon Trust Company
P.O. Box 7010 Adelaide Street Station
Toronto, Ontario Canada M5C 2W9
Phone
Toll-free in North America: 1.800.387.0825
Toronto or outside North America: 416.643.5500
Fax
416.643.5501
Website
www.cibcmellon.com

FOR MORE INFORMATION
Media inquiries
Bob Klager
Director, Public Affairs
Phone
403.267.7330
E-mail
robert_klager@transalta.com

Investor inquiries
Jess Nieukerk
Director, Investor Relations
Phone
1.800.387.3598 in Canada and United States
or 403.267.2520
Fax
403.267.2590
E-mail
investor_relations@transalta.com