TRANSALTA CORP
Form 6-K
October 18, 2002

FORM 6-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16
of the Securities Exchange Act of 1934

For the month of October, 2002

TRANSALTA CORPORATION

(Translation of registrant's name into English)

110-12th Avenue S.W., Box 1900, Station "M", Calgary, Alberta, T2P 2M1

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F____ Form 40-F X

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ..... No ..X...

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-________

Evaluation of Disclosure Controls and Procedures

TransAlta has designed disclosure controls and procedures to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to the Chief Executive Officer and Chief Financial Officer by others within the Company, including its consolidated subsidiaries, on a regular basis, in particular during the period in which its Current Reports on Form 6-K relating to quarterly financial results are being prepared. The Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as of a date within 90 days of the date of this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded, as of that evaluation date, that the Company's disclosure controls and procedures were effective to ensure that material information relating to the Company, including its consolidated subsidiaries, was made known to them by others within those entities during the period in which this report was being prepared. There have been no significant changes in the internal controls or in other factors that could significantly affect internal controls subsequent to the date of the most recent evaluation by the Chief Executive Officer and Chief

Financial Officer, including any corrective action with regard to significant deficiencies and material weaknesses.

EXHIBITS

Exhibit 1	Press Release dated October 17, 2002.
Exhibit 2	Quarterly report for the three-month period ended September 30, 2002, which includes Management's Discussion and Analysis and consolidated financials statements.

TransAlta reports higher third quarter earnings and strong operational performance

CALGARY, Alberta (Oct. 17, 2002) - TransAlta Corporation (TSX: TA; NYSE: TAC) today announced third quarter net earnings applicable to common shareholders of $67.9 million ($0.40 per share), up from $41.4 million ($0.25 per share) in the same quarter of 2001. As all discontinued operations were sold by June 30, 2002, third quarter earnings from continuing operations applicable to common shareholders were also $67.9 million, up from $33.4 million ($0.20 per share) in the same quarter of the previous year.

Financial results reflect continued strong operating performance of the overall fleet. Plant availability increased to 87.3 per cent from 84.9 per cent due to improved availability at the coal plants. Production was at the prior year's level, as the company continued to purchase power from spot markets to satisfy contracts when power prices were below the cost of running the plants. The improved results also reflect the recognition of certain previously unrecorded tax losses carried forward, lower operating costs and the impact last year of losses related to power purchased to offset unplanned outages at Centralia, partially offset by reduced Energy Marketing results.

"The market continues to be difficult for the electricity industry and we are continuing to focus our efforts on the fundamentals of cost and availability," said Steve Snyder, TransAlta's president and CEO. "With our strong balance sheet we expect to be able to take advantage of an increasing number of attractively priced acquisition opportunities to grow our capacity."

Cash used in operating activities including changes in working capital was $14.2 million, compared to cash provided from operating activities of $65.8 million in third quarter 2001. This decrease was mainly due to the settlement of a previously disputed ancillary services revenue issue with the Balancing Pool of Alberta that had no impact on earnings and to the timing of income tax payments.

TransAlta consolidated financial highlights

(In millions except per share amounts)	3 months ended September 30				9 months ended September 30			
	2002		2001		2002		2001	
	Amount	Per share	Amount	Per share	Amount	Per share	Amount	Per share
Revenue from continuing operations*	$ 450.3		$ 573.3		$ 1,206.3		$ 1,885.0	
Net earnings from continuing operations**	$ 67.9	$ 0.40	$ 33.4	$ 0.20	$ 121.4	$ 0.72	$ 136.3	$ 0.81
Discontinued operations	-	-	$ 8.0	$ 0.05	$ 12.8	$ 0.07	$ 31.8	$ 0.19
Gain on sale	-	-	-	-	$ 110.0	$ 0.65	-	-
Net earnings**	$ 67.9	$ 0.40	$ 41.4	$ 0.25	$ 244.2	$ 1.44	$ 168.1	$ 1.00
Cash flow from operating activities	$ (14.2)		$ 65.8		$ 248.2		$ 583.9	

* Trading revenues are now being reported on a net basis

** Applicable to common shareholders, net of preferred securities distributions

	3 months ended September 30		*9 months ended September 30*	
	2002	2001	2002	2001
Availability (%)	87.3	84.9	88.9	84.0
Production (GWh)	11,395	11,413	34,399	33,166
Electricity trading volumes (GWh)	33,985	5,579	76,900	12,497
Gas trading volumes (million GJ)	30.8	37.2	119.0	62.8

(more)

Discontinued operations in 2001 and 2002 include net earnings from the Transmission operation, which was sold in April 2002. Results for 2001 also include the Edmonton Composter operation, which was sold in June 2001.

In third quarter 2002, TransAlta:

Commissioned the Big Hanaford power plant - on time and below budget. The 248-megawatt natural gas combined-cycle facility is located on the site of TransAlta's 1,404-megawatt coal-fired facility in Centralia, Washington. The gas-fired plant will provide additional flexibility to the Centralia coal-fired plant.

Removed from service the 154-megawatt short-term leased Pierce Power Station located in Frederickson, Washington, as intended when commissioned in August 2001. TransAlta built the simple-cycle gas-fired power facility to help alleviate a short-term power shortage in the Pacific Northwest. The plant was fully depreciated on removal from service.

Spent $182 million on capital expenditures to maintain equipment and expand capacity.

Increased electricity trading volumes from 5,579 GWh to 33,985 GWh at a time when many other trading operations were losing money or shutting down. The increased trading activities specifically increased our volumes in short term markets.

Reverted to presenting revenues from energy trading activities on a net basis, to conform to new rules from the U.S. Financial Accounting Standards Board. TransAlta has always believed that method of presentation is appropriate.

Certified the financial results in accordance with the Sarbanes-Oxley Act requirements.

In fourth quarter 2000, TransAlta made a provision of US$29 million against US$58 million owing from the California Independent System Operator and the California Power Exchange. Subsequently, US$5 million has been collected. No change has been made to the provision.

TransAlta Corporation is Canada's largest non-regulated electric generation and marketing company, with more than $7 billion in assets and 9,000 megawatts of capacity either in operation or under construction. As one of North America's lowest-cost operators, our growth is focused on developing coal- and gas-fired generation in Canada, the U.S. and Mexico.

This news release may contain forward-looking statements, including statements regarding the business and anticipated financial performance of TransAlta Corporation. 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.

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TRANSALTA CORPORATION

Q3 2002

Management's Discussion and Analysis

This discussion and analysis should be read in conjunction with the unaudited consolidated financial statements of TransAlta Corporation (TransAlta or the corporation) as at and for the three and nine months ended Sept. 30, 2002 and 2001, and should also be read in conjunction with the audited consolidated financial statements and Management's Discussion and Analysis contained in TransAlta's annual report for the year ended Dec. 31, 2001. 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.

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of TransAlta. These statements involve known and unknown risks and relate to future events, future financial performance and projected business results. In some cases, forward-looking statements can be identified by terms such as 'may', 'will', 'believe', 'expect', 'potential', 'enable', 'continue' or other comparable terminology. These forward-looking statements are subject to a number of uncertainties that may cause actual results to differ materially from those contemplated in the forward-looking statements. Some of the factors that could cause such differences include legislative and regulatory developments that could affect revenues, costs, the speed and degree of competition entering the market, global capital markets activity, timing and extent of changes in prevailing interest rates, currency exchange rates, inflation levels, weather conditions and general economic conditions in geographic areas where TransAlta operates, including generation capacity and supply and demand for electricity and natural gas, results of financing efforts, changes in counterparty risk and the impact of accounting policies issued by Canadian and United States standard setters.

RESULTS OF OPERATIONS

The results of operations are organized by consolidated results and by business segment. TransAlta has two business segments: Generation and Energy Marketing. A third business segment, Independent Power Projects (IPP), was combined with the Generation segment effective Jan. 1, 2002, following changes to TransAlta's organizational structure. A fourth business segment, Transmission, was sold on April 29, 2002. Accordingly, prior period amounts have been reclassified. Corporate overheads that are not directly attributable to discontinued operations are allocated to the business segments. The corporate group provides finance, treasury, legal, human resources and other administrative support to the business segments.

The business segments assume responsibility for their operating results measured as earnings before interest, taxes and non-controlling interests (EBIT). EBIT should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with Canadian GAAP as an indicator of the corporation's performance or liquidity. TransAlta's EBIT is not necessarily comparable to a similarly titled measure of another company. EBIT can be determined from the consolidated statements of earnings by deducting earnings and gains from discontinued operations, other income and foreign exchange gains and adding net interest expense, prior period regulatory decisions, income taxes and non-controlling interests to net earnings.

HIGHLIGHTS

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

3 months ended Sept. 30	**2002**		2001	
Availability	**87.3%**		84.9%	
Production (GWh)	**11,395**		11,413	
Electricity trading volumes (GWh)[1]	**33,985**		5,579	
Gas trading volumes (million GJ)	**30.8**		37.2	
	Amount	**Per common share**	Amount	Per common share
Revenues[2]	**$ 450.3**		$ 573.3	
Net earnings from continuing operations[3]	**$ 67.9**	**$ 0.40**	$ 33.4	$ 0.20
Discontinued operations[4]	**-**	**-**	8.0	0.05
Net earnings applicable to common shareholders	**$ 67.9**	**$ 0.40**	$ 41.4	$ 0.25
Cash flow from (used in) operating activities	**$ (14.2)**		$ 65.8	

9 months ended Sept. 30	**2002**		2001	
Availability	**88.9%**		84.0%	
Production (GWh)	**34,399**		33,166	
Electricity trading volumes (GWh)[1]	**76,900**		12,497	
Gas trading volumes (million GJ)	**119.0**		62.8	
	Amount	**Per common share**	Amount	Per common share
Revenues[2]	**$ 1,206.3**		$ 1,885.0	
Net earnings from continuing operations[3]	**$ 121.4**	**$ 0.72**	$ 136.3	$ 0.81
Discontinued operations[4]	**12.8**	**0.07**	31.8	0.19
Gain on disposal of discontinued operations[4]	**110.0**	**0.65**	-	-
Net earnings applicable to common shareholders	**$ 244.2**	**$ 1.44**	$ 168.1	$ 1.00
Cash flow from operating activities	**$ 248.2**		$ 583.9	

[1] 2001 electricity trading volumes have been restated to conform with current reporting

practices and standards.

[2] From continuing operations. In accordance with changes to U.S. and Canadian GAAP, revenues from energy trading activities are now presented on a net basis. Prior period amounts have been reclassified to reflect this change.

[3] Continuing operations include the Generation and Energy Marketing segments plus corporate costs not directly attributable to discontinued operations, and are net of preferred securities distributions.

[4] Discontinued operations include the Transmission operation and the Edmonton Composter operation. The Transmission operation was sold on April 29, 2002 and the Edmonton Composter was sold on June 29, 2001.

Net earnings from continuing operations for the three months ended Sept. 30, 2002 compared to the same period of 2001 reflect improved plant availability and contracted prices, lower operating costs and the utilization and recognition of previously unrecognized tax losses, partially offset by reduced energy marketing results. Net earnings from continuing operations for the nine months ended Sept. 30, 2002 compared to 2001 were also influenced by the negative impact of the Wabamun unit four arbitration decision ($38.9 million plus interest of $2.7 million) and a prior period regulatory decision ($3.3 million) described below. Net earnings attributable to common shareholders include the $110.0 million ($0.65 per common share) after-tax gain on disposal of the Transmission operation, which was sold on April 29, 2002.

As a result of the issuance of EITF 02-3, *Recognition of Gains and Losses on Energy Trading Contracts*, by the Financial Accounting Standards Board in the U.S., revenues from energy trading activities are now presented on a net basis. Prior period amounts have been reclassified for this change. This standard has been adopted for Canadian GAAP as well.

Cash flow used in operating activities for the three months ended Sept. 30, 2002 was $14.2 million compared to cash flow provided by operating activities of $65.8 million in the comparable period of 2001 due primarily to the settlement of a disputed ancillary services revenue issue with the Balancing Pool of Alberta, which had no impact on earnings and the timing of income tax payments. For the nine months ended Sept. 30, 2002, cash flow from operating activities was $248.2 million compared to $583.9 million in 2001 for the reasons noted above, plus the favourable impact of the timing of accounts receivable relating to the Alberta Power Pool for Generation ($170.0 million) upon implementation of deregulation on Jan. 1, 2001, and the final instalment of 2001 income taxes paid in the first quarter of 2002 ($109.0 million).

The corporation's existing financial reporting procedures and practices have enabled the certification of TransAlta's third quarter report to shareholders in accordance with the requirements of the Sarbanes Oxley Act.

SIGNIFICANT ONE-TIME ITEMS

Gain on disposal of discontinued operations

On April 29, 2002, TransAlta's Transmission operation was sold for proceeds of $821.0 million, of which $3.0 million remains outstanding. The proceeds excluded $31.7 million in accounts receivable, which were retained and subsequently collected by TransAlta, and $4.4 million in accounts payable. The disposal resulted in a gain on sale of $110.0 million ($0.65 per common share), net of income taxes of $32.9 million. The gain on disposal reflects management's best estimate. The final gain on sale will be adjusted to reflect actual amounts, which are expected to be finalized by Dec. 31, 2002.

Wabamun arbitration decision

On May 23, 2002, the corporation received the arbitrators' decision with respect to the 10 month outage at Wabamun unit four, which resulted from fatigue cracks within the waterwall tubing of its boiler. The arbitrators confirmed in their ruling that the outage qualified as a *force majeure* event, but also ruled that the corporation should have returned the unit to service more quickly. As a result of this decision, the corporation was required to pay $38.9 million plus interest of $2.7 million.

Prior period regulatory decision

On April 16, 2002, the Alberta Energy and Utilities Board (EUB) rendered a negative decision of $3.3 million with respect to TransAlta's hydro bidding strategy in 2000. The impact of regulatory decisions is recorded when the effect of such decisions is known, without adjustment to the financial statements of prior periods. Consequently, the adjustment was recorded in the second quarter of 2002.

Refinancing of foreign operations

During the third quarter of 2002, TransAlta restructured the financing of certain of its foreign operations. As a result, the company was able to record the benefit of previously unrecognized foreign tax loss carryforward balances. This restructuring contributed $11.2 million to earnings in the current period.

Ancillary services revenue settlement

In July 2002, a dispute with the Balancing Pool of Alberta in respect of the allocation of hydro ancillary services revenue under the Hydro Power Purchase Arrangements was resolved. TransAlta repaid $49.9 million of revenue received in advance from the Balancing Pool, which was subject to resolution of the dispute. The settlement had no earnings impact as the corporation had not previously recognized the amount as revenue..

Pierce Power decision

In September 2001, TransAlta monetized its investment in the 154 MW Pierce Power plant as a result of weak economic conditions. Revenue hedges were realized resulting in the recognition of revenue of $121.8 million, a write-down in the carrying amount of property, plant and equipment of $66.5 million and $49.6 million recognized in anticipated future plant operating costs, included in operations, maintenance and administration expense (OM&A).

NEW ACCOUNTING STANDARDS

Effective Jan. 1, 2002, the corporation prospectively adopted the new Canadian Institute of Chartered Accountants (CICA) standard for goodwill and other intangibles. Under the new standard, goodwill and certain intangibles are no longer subject to amortization, but are instead tested for impairment at least annually. The adoption of this standard resulted in the reclassification of $29.3 million from acquired intangibles to goodwill, which will no longer be subject to amortization under the new standard. There was no impairment of goodwill upon adoption of this standard.

On Jan. 1, 2002, the corporation retroactively adopted the new CICA standard for stock-based compensation. The new standard requires that stock-based payments to non-employees, direct awards of stock and awards that call for settlement in cash or other assets be accounted for using the fair value method of accounting. The fair value method is encouraged for other stock-based compensation plans, but other methods of accounting, such as the intrinsic value method, are permitted. Under the fair value method, compensation expense is measured at the grant date and recognized over the service period. Under the intrinsic value method, compensation expense is determined as the difference between the market price of the underlying stock and the exercise price of the equity instrument granted. If the intrinsic value method is used, disclosure is made of earnings and per share amounts as if the fair value method had been used. The corporation has elected to use the intrinsic value method of accounting for its fixed stock option plans and its performance stock option plan. Accordingly, no compensation cost has been recognized for these plans. Had the fair value method been used, reported basic and diluted earnings per common share would have been reduced by $0.01 and $0.02 per common share for the three and nine months ended Sept. 30, 2002 (2001 - $nil and $0.01 per common share).

The CICA amended its standard on foreign currency translation effective Jan. 1, 2002. The changes require that translation gains and losses arising on long-term foreign currency denominated monetary items be included in income in the current period. Previously, these gains and losses were to be amortized over the life of the related item. As TransAlta designates long-term foreign currency denominated items as hedges of net investments in foreign operations, all gains and losses arising on the translation of these items are deferred and included in the cumulative translation adjustment account in shareholders' equity, therefore this amendment has no impact on TransAlta.

In June 2002, the Emerging Issues Task Force (EITF) in the U.S. reached a consensus in EITF 02-3 that all mark-to-market gains and losses on energy trading contracts should be shown net in the statement of earnings whether or not settled physically, effective for financial statements issued for periods ending after July 15, 2002, with reclassification of prior periods presented. An entity should also disclose the gross transaction volumes for those energy trading contracts that are physically settled. TransAlta has adopted this standard for Canadian GAAP as well. Commencing in the quarter ended Sept. 30, 2002, TransAlta has presented all energy trading and marketing activities on a net basis in the consolidated statements of earnings and retained earnings.

DISCUSSION OF SEGMENTED RESULTS

GENERATION: ***Owns and operates hydro- , gas- and coal- fired plants and related mining operations, with a total generating capacity of 7,528 MW.***

Effective Jan. 1, 2002, TransAlta's organizational structure changed to combine the Generation and IPP business segments into one Generation segment to improve the corporation's operational capability and reliability through the sharing of resources and best practices across all generating assets. Prior period amounts have been reclassified to reflect the combination of these segments.

	2002		2001	
3 months ended Sept. 30	Total	Per MWh	Total	Per MWh
Revenues	**$ 431.8**	**$ 37.89**	$ 527.8	$ 46.24
Fuel and purchased power	**(173.2)**	**(15.20)**	(250.5)	(21.94)
Gross margin (GM)	**258.6**	**22.69**	277.3	24.30
Operating expenses:				
Operations, maintenance and administration	**76.9**	**6.75**	126.2	11.06
Depreciation and amortization	**48.2**	**4.23**	97.1	8.51
Taxes, other than income taxes	**5.9**	**0.52**	4.1	0.36
EBIT before corporate allocations	**127.6**	**11.19**	49.9	4.37
Corporate allocations	**(18.7)**	**(1.64)**	(18.3)	(1.60)
EBIT	**$ 108.9**	**$ 9.55**	$ 31.6	$ 2.77

	2002		2001	
9 months ended Sept. 30	Total	Per MWh	Total	Per MWh
Revenues	**$ 1,175.2**	**$ 34.16**	$ 1,726.6	$ 52.06
Fuel and purchased power	**(476.7)**	**(13.86)**	(984.2)	(29.67)
Gross margin	**698.5**	**20.30**	742.4	22.39
Operating expenses:				
Operations, maintenance and administration	**231.0**	**6.71**	279.0	8.41
Depreciation and amortization	**138.9**	**4.04**	174.1	5.25
Taxes, other than income taxes	**19.7**	**0.57**	14.1	0.43
Prior period regulatory decision	**3.3**	**0.09**	-	-
EBIT before corporate allocations	**305.6**	**8.89**	275.2	8.29
Corporate allocations	**(52.5)**	**(1.53)**	(58.9)	(1.78)
EBIT	**$ 253.1**	**$ 7.36**	$ 216.3	$ 6.52

3 months ended Sept. 30	2002		2001	
	Revenue	GM	Revenue	GM
Contract	**$ 387.6**	**$ 245.8**	$ 344.6	$ 178.2
Merchant	**36.0**	**4.6**	147.3	63.2
Ancillary services and other	**8.2**	**8.2**	35.9	35.9
Wabamun arbitration decision	**-**	**-**	**-**	-
	$ 431.8	**$ 258.6**	$ 527.8	$ 277.3

9 months ended Sept. 30	2002		2001	
	Revenue	GM	Revenue	GM
Contract	**$ 1,042.9**	**$ 648.9**	$ 1,000.3	$ 360.6
Merchant	**116.2**	**33.5**	632.5	288.0
Ancillary services and other	**55.0**	**55.0**	93.8	93.8
Wabamun arbitration decision	**(38.9)**	**(38.9)**	-	-
	$ 1,175.2	**$ 698.5**	$ 1,726.6	$ 742.4

	Production (GWh)	Revenue	EBIT
3 months ended Sept. 30, 2001	11,413	$ 527.8	$ 31.6
Impact of the Pierce Power plant monetization in 2001	-	(121.8)	(5.7)
Higher contracted prices	-	25.8	25.8
Lower purchased power requirements, including hedge losses	-	-	67.9
Higher availability offset by decrease in production	(18)	(0.8)	(0.5)
Lower fuel costs per megawatt hour	-	-	10.1
Timing of scheduled maintenance and cost reductions	-	-	(0.3)
Increased depreciation	-	-	(17.6)
Higher property taxes	-	-	(1.8)
Other	-	0.8	(0.6)
3 months ended Sept. 30, 2002	11,395	**$ 431.8**	**$ 108.9**

	Production (GWh)	Revenue	EBIT
9 months ended Sept. 30, 2001	33,166	$ 1,726.6	$ 216.3
Wabamun arbitration decision	-	(38.9)	(38.9)
Prior period regulatory decision	-	-	(3.3)

Impact of the Pierce Power plant monetization in 2001	-	(121.8)	(5.7)
Lower market prices	-	(447.1)	(447.1)
Lower purchased power requirements, including hedge losses	-	-	487.4
Net improved availability and production	1,233	58.7	43.2
Lower fuel costs per megawatt hour	-	-	37.1
Increased operations, maintenance and administration expense	-	-	(1.7)
Increased depreciation	-	-	(31.2)
Higher property taxes	-	-	(4.6)
Other	-	(2.3)	1.6
9 months ended Sept. 30, 2002	34,399	**$ 1,175.2**	**$ 253.1**

RESULTS: Generation's revenues are derived from the production of electricity, of which, on an annualized basis, approximately 90 per cent are based upon contracted prices, including capacity payments, and approximately 10 per cent are subject to market pricing and from the provision of other ancillary services such as steam and system support. The percentage allocations are subject to seasonal variations. During the summer months, warmer temperatures result in reduced fuel conversion rates (heat rates) and increased hydro production from spring run-off results in lower electricity prices.

Availability for the third quarter of 2002 was 87.3 per cent compared to 84.9 per cent in 2001, reflecting improved operational performance at the thermal and gas plants. At certain times during the second and third quarters of 2002, when the market price of electricity was lower than the variable costs of production at certain plants, the corporation reduced production at these plants, and purchased electricity from the market to fulfill contractual obligations. During these periods of economic dispatch, the affected plants were available to generate the electricity if required. Availability for the first nine months of 2002 was 88.9 per cent compared to 84.0 per cent in 2001 for the same reasons discussed above.

Production arising from increased availability was partially offset by the economic dispatch decisions discussed above. During the three and nine months ended Sept. 30, 2002, production decreased by 523.6 GWh and 730.6 GWh respectively (2001 - nil) as a result of these decisions. In the three months ended Sept. 30, 2002, this was partially offset by improved production from the Alberta thermal plants and improved hydro production. During the nine months ended Sept. 30, 2002, production increased by 1,233 MWh, primarily as a result of the return to service of Wabamun unit four, partially offset by reduced production resulting from the economic dispatch

decisions discussed above.

Spot prices	Q3 2001	Q3 2002	YTD 2001

				YTD 2002
Alberta System Market Price (Cdn$)	$45.42	$ 34.59	$ 83.11	$ 38.06
Mid-Columbia Price (US$)	$ 38.66	$ 17.38	$ 164.87	$ 19.12

Spark spreads	Q3 2001	Q3 2002	YTD 2001	YTD 2002
Alberta System Market Price vs. AECO (Cdn$)	$ 23.57	$ 12.43	$ 40.11	$ 13.08
Mid-Columbia Price vs. Sumas (US$)	$ 22.04	$ 3.02	$ 134.62	$ 2.93

As shown in the above graphs, for the three and nine months ended Sept. 30, 2002, spot prices and spark spreads (sales price less cost of fuel) in both the Alberta and Pacific Northwest markets declined substantially compared to the same periods of 2001. Within these markets, prices were softer due to reduced demand as a result of lower economic activity, increased hydro production, additional generating capacity added to these markets and lower gas prices. In addition, the first quarter of 2002 was unseasonably warm, resulting in lower gas prices and consequently lower electricity prices.

As discussed previously, the arbitrators rendered their decision in 2002 with respect to the *force majeure* dispute concerning the outage at Wabamun unit four. The ruling confirmed that the outage qualified under the *force majeure* provision of the power purchase arrangement (PPA), but ruled that TransAlta should have returned the unit to service more quickly. As a result, TransAlta was required to pay $38.9 million plus interest of $2.7 million. The $38.9 million payment was recorded as a reduction of revenue.

In September 2001, TransAlta monetized its investment in the 154 MW Pierce Power plant as a result of weak economic conditions. Revenue hedges were realized resulting in the recognition of revenue of $121.8 million, a write-down in the carrying amount of property, plant and equipment of $66.5 million and $49.6 million recognized in anticipated future plant operating costs, included in OM&A.

As a result of the lower market prices discussed above, Generation's revenue for the third quarter of 2002 was $431.8 million ($37.89 per MWh) compared to $527.8 million ($46.24 per MWh) in the same period in 2001. Revenue for the first nine months of 2002 was $1,175.2 million ($34.16 per MWh) compared to $1,726.6 million ($52.06 per MWh). Excluding the Pierce Power decision discussed above, revenue for the three months ended Sept. 30, 2002 increased by $25.8 million compared to $406.0 million ($35.57 per MWh) in 2001, primarily as a result of higher contracted prices at the gas plants due to increased gas prices. For the nine months ended Sept. 30, revenue, adjusted for the Wabamun arbitration and Pierce Power decisions, was $1,214.1 million ($35.29 per MWh) in 2002 compared to $1,604.8 million ($48.39 per MWh) in 2001. The decline in revenue from 2001 reflects lower market prices for non-contracted production in 2002, partially offset by improved production and availability.

Revenues received under long-term contractual arrangements are not subject to major fluctuations in the spot price for electricity. These contracts covered approximately 90 per cent of production in the third quarter of 2002 (2001 - 94 per cent) at an average price of $34.27 per MWh (2001 - $32.70). The remaining ten per cent of production (2001 - six per cent) was subject to market pricing at an average price of $33.14 per MWh (2001 - $34.17). For the first nine months of the year, these contracts covered approximately 89 per cent of total production (2001 - 90 per cent) at an average price of $33.45 per MWh (2001 - $33.51). The remaining 11 per cent (2001 - 10 per cent) was subject to market pricing at an average price of $33.72 per MWh (2001 - $153.30). The fluctuations in contracted prices are due to higher gas prices during the quarter, which are recovered under the terms of certain contracts, and the seasonal nature of the corporation's operations, as discussed above. The existing contracts have remaining terms ranging from one to 23 years.

Fuel and purchased power decreased to $173.2 million ($15.20 per MWh) in the third quarter of 2002 compared to $250.5 million ($21.94 per MWh) in 2001. For the first nine months of 2002, fuel and purchased power decreased to $476.7 million ($13.86 per MWh) from $984.2 million ($29.67 per MWh) in 2001. Purchased power is the cost incurred to acquire electricity from the market to fulfill contracted commitments during planned and unplanned outages. Any electricity not required to fulfill these commitments is sold back into the market at spot prices.

In the third quarter and first nine months of 2002, improved availability and lower market prices resulted in a reduction in purchased power costs to $27.0 million and $35.6 million, respectively. The majority of the purchased power requirement in 2002 was due to the economic dispatch decisions discussed earlier. In the third quarter of 2001, lower availability at the Centralia plant resulted in the purchase of 492 GWh of electricity, totaling $94.9 million. For the first nine months of 2001, 1,513 GWh of electricity totaling $523.0 million was purchased. Pre-tax losses in the three and nine months ended Sept. 30, 2001 were US$49.7 million (approximately Cdn$77 million) as a result of these purchases.

Fuel costs, excluding purchased power, were $146.2 million ($12.83 per MWh) in the third quarter of 2002 compared to $155.6 million ($13.63 per MWh) for the same period in 2001. For the first nine months of 2002, fuel costs excluding purchased power totaled $441.1 million ($12.82 per MWh) compared to $461.2 million ($13.91 per MWh) in 2001. Lower production in the third quarter of 2002 was combined with lower coal production costs due to cost reduction initiatives implemented throughout 2002, offset by higher gas costs. For the first nine months of 2002 fuel costs decreased as a result of lower coal production costs, partially offset by increased production.

In the third quarter of 2002, OM&A expenses decreased to $76.9 million ($6.75 per MWh) from $126.2 million ($11.06 per MWh) in 2001. In the nine months ended Sept. 30, 2002, OM&A decreased to $231.0 million ($6.71 per MWh) from $279.0 million ($8.41 per MWh) in 2001. Excluding the impact of the Pierce Power decision described above, OM&A for the three months ended Sept. 30, 2001 was $76.6 million ($6.71 per MWh), which is comparable to the third quarter of 2002. Excluding this decision for the nine months ended Sept. 30, 2001, OM&A was $229.4 million ($6.92 per MWh), which, on a per MWh basis, is slightly higher than in 2002, reflecting the impact of the cost reduction initiatives.

Depreciation and amortization for the third quarter of 2002 decreased to $48.2 million ($4.23 per MWh) compared to $97.1 million ($8.51 per MWh) in 2001. For the first nine months of 2002, depreciation and amortization decreased to $138.9 million ($4.04 per MWh) from $174.1 million ($5.25 per MWh) in 2001. Excluding the impact of the Pierce Power decision, depreciation and amortization increased by $17.6 million in the third quarter of 2002 compared to $30.6 million ($2.68 per MWh) in the third quarter of 2001, and increased by $31.3 million in the nine months ended Sept. 30, 2002 compared to $107.6 million ($3.24 per MWh) in the same period of 2001. The increases were a result of the commissioning of the Big Hanaford plant in August 2002 and increased depreciation on capital expenditures incurred at the Wabamun and Centralia plants.

The increase in taxes other than income taxes in the three and nine months ended Sept. 30, 2002 relates to higher property tax assessments by local municipalities on the majority of the corporation's plants.

On April 16, 2002, the Alberta Energy and Utilities Board (EUB) rendered a negative decision of $3.3 million with respect to TransAlta's hydro bidding strategy in 2000. As the impact of regulatory decisions is recorded when the effect of such decisions is known without adjustment to the financial statements of prior periods, the adjustment was recorded in 2002 as a prior period regulatory decision.

ENERGY MARKETING: ***Derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. These activities also provide critical market knowledge to help identify growth opportunities and support corporate investment decisions.***

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Gross revenues	**$ 1,358.6**	$ 424.0	**$ 2,711.4**	$ 2,167.8
Trading purchases	**(1,340.1)**	(378.5)	**(2,680.3)**	(2,009.4)
Net revenues	**18.5**	45.5	**31.1**	158.4
Operations, maintenance and administration	**5.0**	7.5	**11.5**	34.6
Depreciation and amortization	**0.6**	2.9	**2.0**	7.0
Taxes, other than income taxes	**0.1**	-	**0.1**	-
EBIT before corporate allocations	**12.8**	35.1	**17.5**	116.8
Corporate allocations	**(2.1)**	(1.5)	**(6.0)**	(4.7)
EBIT	**$ 10.7**	$ 33.6	**$ 11.5**	$ 112.1

	Trading volumes			
	Electricity (GWh)	**Gas (million GJ)**	**Gross revenue**	**EBIT**
3 months ended Sept. 30, 2001	5,579	37.2	$ 424.0	$ 33.6
Increased electricity and gas volumes offset by decreased margins	28,406	(6.4)	934.6	(27.0)
Increased operating costs	-	-	-	(1.7)

Lower depreciation and amortization costs	- -	-		
One-time costs associated with MEGA acquisition in 2001	- -	-	4.1	
Higher corporate allocations	- -	-	(0.6)	
3 months ended Sept. 30, 2002	33,985	**30.8**	**$ 1,358.6**	**$ 10.7**

	Electricity (GWh)	**Gas (million GJ)**	**Gross revenue**	**EBIT**
9 months ended Sept. 30, 2001	12,497	62.8	$ 2,167.8	$ 112.1
Increased electricity and gas volumes offset by decreased pricing and margins	64,403	56.2	543.6	(127.3)
Decreased operating costs	- -	-	11.0	
Lower depreciation and amortization costs	- -	-	5.0	
One-time costs associated with MEGA acquisition in 2001	- -	-	12.0	
Higher corporate allocations	- -	-	(1.3)	
9 months ended Sept. 30, 2002	76,900	**119.0**	**$ 2,711.4**	**$ 11.5**

Gross physical and financial settled sales transactions are as follows:

	3 months ended Sept. 30		**9 months ended Sept. 30**	
Electricity (GWh)	2002	2001	**2002**	2001
Physical	**22,260**	3,180	**50,006**	8,748
Financial	**11,725**	2,399	**26,894**	3,749
	33,985	5,579	**76,900**	12,497

	3 months ended Sept. 30		9 months ended Sept. 30	
Gas (million GJ)	2002	2001	**2002**	2001
Physical	**29.1**	8.7	**74.8**	18.4
Financial	**1.7**	28.5	**44.2**	44.4
	30.8	37.2	**119.0**	62.8

The Energy Marketing group uses energy derivatives, including physical and financial swaps, forwards and options to gain market information and to earn trading revenues. Trading activities are accounted for at fair value in accordance with Canadian and U.S. GAAP. Similar products are used to hedge the corporation's exposure to changes in electricity and natural gas prices. Under Canadian GAAP, settlement accounting is used for hedging activities if certain criteria are met. Under U.S. GAAP, hedging activities are accounted for in accordance with FASB Statement 133, *Accounting for Derivative Instruments and Hedging Activities*.

Gross trading sales volumes during the third quarter of 2002 increased to 33,985 GWh of electricity compared to 5,579 GWh in 2001 and decreased to 30.8 million gigajoules (GJ) of gas in 2002 compared to 37.2 million GJ in 2001. In the first nine months of 2002, trading volumes were 76,900 GWh of electricity and 119.0 million GJ of gas compared to 12,497 GWh of electricity and 62.8 million GJ of gas in 2001. The increase in electricity trading volumes is a result of increased trading activities in the short-term market as wholesale customers re-entered the market to satisfy their physical and risk management requirements. TransAlta benefited from this increased activity as a result of its strong balance sheet and credit rating. The terms of transactions were shorter than previously experienced, resulting in an increased number of transactions and volumes traded. Liquidity in the medium- to long-term markets remained low and as a result, Energy Marketing continued to have a low level of activity in these markets.

Gross revenues increased to $1,358.6 million in the three months ended Sept. 30, 2002 from $424.0 million in the same period of 2001 and increased to $2,711.4 million in the nine months ended Sept. 30, 2002 from $2,167.8 million in the nine months ended Sept. 30, 2001. Increased electricity trading volumes in 2002 more than offset lower market prices and the decline in gas trading activities in the first and second quarters.

Net revenues decreased to $18.5 million for the three months ended Sept. 30, 2002 from $45.5 million for the same period in 2001 and decreased to $31.1 million for the first nine months of 2002 from $158.4 million in the first nine months of 2001. The decreases were due to significantly lower market prices, as shown in the graphs in the Generation discussion, particularly in the Pacific Northwest. The 2001 Pacific Northwest prices were influenced by the process of deregulation in California, exacerbated by a drought in the Pacific Northwest and historically high natural gas prices. In addition, the price spread between purchases and sales declined as volumes increased.

OM&A expense for the third quarter of 2002 decreased to $5.0 million from $7.5 million in the same period of 2001 and decreased to $11.5 million for the nine months ended Sept. 30, 2002 from $34.6 million in the same period of 2001. The decreases were due primarily to lower incentive compensation and one-time costs associated with the acquisition of the remaining 50 per cent of Merchant Energy Group of the Americas, Inc. (MEGA) in June 2001.

Depreciation and amortization for the third quarter decreased to $0.6 million from $2.9 million in 2001, and decreased to $2.0 million from $7.0 million in the first nine months of the year, as goodwill arising from previous acquisitions, previously recorded as acquired intangibles, is no longer being amortized. This treatment is in accordance with the new accounting standard issued by the CICA. There was no impairment of goodwill upon adoption of the standard on Jan. 1, 2002.

Energy Marketing's price risk management assets and liabilities represent the fair value of unsettled (unrealized) trading transactions. With the exception of transmission contracts, the fair value of all energy trading activities is based on quoted market prices. The fair value of transmission contracts is based on quoted market prices and a spread option valuation model.

The following table illustrates movements in the fair value of the corporation's price risk management assets during the nine months ended Sept. 30, 2002:

Fair value of net price risk management assets outstanding at Dec. 31, 2001		**$ 25.8**
Fair value of new contracts entered into during the period	**13.0**	
Contracts realized or settled during the period	**(32.8)**	
Changes in fair values attributable to changes in valuation techniques and assumptions		**-**
Changes in fair values attributable to market price and other market changes		**(5.0)**
Fair value of net price risk management assets outstanding at Sept. 30, 2002		**$ 1.0**

The source of the valuations of the above contracts and maturities over each of the next five calendar years and thereafter is as follows:

	2002	**2003**	**2004**	**2005**	**2006**	**2007 and thereafter**	**Total**
Prices actively quoted	$ 0.9	**$ (6.8)**	**$ 0.8**	**$ 0.7**	**$ 0.8**	**$ 0.4**	**$ (3.2)**
Prices based on models	0.1	**4.1**	**-**	**-**	**-**	**-**	**4.2**
Asset (liability)	$ 1.0	**$ (2.7)**	**$ 0.8**	**$ 0.7**	**$ 0.8**	**$ 0.4**	**$ 1.0**

In the second quarter of 2002, TransAlta responded to a number of inquiries regarding trading activities in California during 2000 and 2001. TransAlta has responded to all inquiries and believes it operated in accordance with all applicable laws, rules, regulations and tariffs. No significant developments occurred on these issues in the third quarter of 2002. In the third quarter of 2002, the U.S. Commodity Futures Trading Commission requested information on similar issues and TransAlta provided the requested information.

In the fourth quarter of 2000, TransAlta made a provision of US$28.8 million against US$58.0 million owing from the California Independent System Operator and the California Power Exchange. During the first quarter of 2001, US$5.0 million was collected. No change has been made to the provision due to the continuing uncertainty in California. The amount has been reclassified to long-term as collection is no longer expected in 2002, although ultimate collected is still expected.

NET INTEREST EXPENSE, FOREIGN EXCHANGE, OTHER EXPENSE, NON-CONTROLLING INTERESTS AND PREFERRED SECURITIES DISTRIBUTIONS

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Net interest expense	**$ 20.9**	$ 12.4	**$ 58.7**	$ 75.7
Other expense (income)	**1.5**	(0.4)	**0.9**	(0.3)
Foreign exchange loss (gain)	**1.0**	2.0	**(0.3)**	2.1
Non-controlling interests	**3.6**	3.7	**14.5**	15.6
Preferred securities distributions, net of tax	**5.5**	3.3	**16.2**	9.6
	$ 32.5	$ 21.0	**$ 90.0**	$ 102.7

Net interest expense (net of interest income, capitalized interest, and amounts allocated to discontinued operations) increased to $20.9 million in the three months ended Sept. 30, 2002 compared to $12.4 million in the same period of 2001. Net interest expense decreased to $58.7 million in the nine months ended Sept. 30, 2002 from $75.7 million in the same period of 2001. The three and nine months ended Sept. 30, 2001 include interest income of $15.5 million related to the deferred accounts receivable from the discontinued Alberta Distribution and Retail (D&R) operation for the period from October 2000 to September 30, 2001, which was recognized in the third quarter of 2001 following an EUB decision. Excluding this amount, net interest expense has declined due to an overall decline in debt levels and higher capitalized interest offset by a higher proportion of debt subject to long-term interest rates.

On June 20, 2002, the corporation issued US$300.0 million of senior notes under a US$1.0 billion shelf registration statement filed May 14, 2002. The proceeds of the issuance were used to repay short-term debt and U.S. denominated commercial paper. The notes bear interest at 6.75 per cent and mature on July 15, 2012.

The decreases in earnings attributable to non-controlling interests in the three and nine months ended Sept. 30, 2002 compared to the same periods of 2001 reflect the redemption of the preferred shares of TransAlta Utilities Corporation for $121.6 million in September 2001, resulting in lower subsidiary preferred share dividends, partially offset by increased earnings from the 49.99 per cent non-controlling interest in TransAlta Cogeneration, L.P. due to the addition of the Fort Saskatchewan plant in the third quarter of 2001.

The increases in preferred securities distributions, net of tax, reflect the issuance of $175.0 million of 7.75 per cent preferred securities in November 2001.

INCOME TAXES

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Income taxes	**$ 19.2**	$ 10.8	**$ 53.2**	$ 89.4
Effective tax rate	**20.0%**	21.1%	**25.9%**	35.6%

Income taxes increased to $19.2 million in the three months ended Sept. 30, 2002 from $10.8 million for the same period in 2001 and decreased to $53.2 million in the nine months ended Sept. 30, 2002 from $89.4 million for the same period of 2001. The effective income tax rate, expressed as a percentage of earnings from continuing operations before income taxes and non-controlling interests, decreased slightly to 20.0 per cent in the third quarter of 2002 from 21.1 per cent in the third quarter of 2001. The effective tax rate in 2002 reflects the benefit of previously unrecognized foreign loss carryforward balances which were recognized during the quarter as it became more likely than not that they would be utilized. Due to lower earnings in the three months ended Sept. 30, 2001, the 21.1 per cent effective rate reflects the impact of the financing arrangements of TransAlta's foreign operations. The benefits of these arrangements do not vary with earnings. For the nine months ended Sept. 30, 2002, the effective rate declined to 25.9 per cent from 35.6 per cent in the nine months ended Sept. 30, 2001. The decrease was due to the benefit of previously unrecognized loss carryforward balances discussed above.

DISCONTINUED OPERATIONS

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Transmission operation	**$ -**	$ 8.0	**$ 12.8**	$ 31.1
Gain on disposal of Transmission operation	**-**	**-**	**110.0**	**-**
Edmonton Composter operation	**-**	-	**-**	0.7
	$ -	$ 8.0	**$ 122.8**	$ 31.8

On April 29, 2002, TransAlta's Transmission operation was sold for proceeds of $821.0 million, of which $3.0 million remains outstanding. The proceeds excluded $31.7 million in accounts receivable, which were retained and subsequently collected by TransAlta, and $4.4 million in accounts payable. The disposal resulted in a gain on sale of $110.0 million ($0.65 per common share), net of income taxes of $32.9 million. The gain on disposal reflects management's best estimate. The final gain on sale will be adjusted to reflect actual amounts, which are expected to be finalized by Dec. 31, 2002.

On June 29, 2001, TransAlta sold its Edmonton Composter for proceeds of $97.0 million, which approximated its book value.

FINANCIAL POSITION

The following chart outlines significant changes in the consolidated balance sheet from Dec. 31, 2001 to Sept. 30, 2002:

	Increase/ (Decrease)	Explanation
Cash and cash equivalents	$ 58.6	*Refer to Consolidated Statements of Cash Flows.*
Accounts receivable and other	(224.7)	*Decrease primarily due to collection of receivable related to monetized Pierce Power hedges ($82 million) timing of PPA receivables ($73 million) and reclassification of California receivables to long-term.*
Income taxes receivable	71.1	*Final instalment of 2001 income taxes paid in the first quarter of 2002, offset by current year additional prepayments.*
Materials and supplies, at average cost	26.6	*Higher coal inventory balances as a result of second and third quarter economic dispatch decisions and increased production of coal.*
Long-term receivables	(103.0)	*Receipt of amount due from Aquila (formerly UtiliCorp) relating to the sale of the discontinued D&R operation, offset by increase in sulphur tax abatement and reclassification of California receivables to long-term.*
Property, plant and equipment, net of accumulated depreciation	(81.2)	*Capital expenditures and construction activity during the period, more than offset by depreciation and the sale of the Transmission operation.*
Other assets	22.9	*Financing costs related to US$300.0 million debt issuance and financings of Mexican projects.*
Short-term debt	(535.7)	*Repayment with a portion of the proceeds on disposal of the Transmission operation.*
Accounts payable and accrued liabilities	(116.1)	*Decrease due to the timing of expenditures.*
Price risk management liabilities (current and long-term)	34.9	*Decrease in margins on energy trading activities.*
Long-term debt (including current portion)	326.6	*US$300.0 million debt issuance, offset by net decrease in long-term commercial paper repaid with proceeds on disposal of the Transmission operation.*
Shareholders' equity	123.5	*Net earnings offset by dividends and net redemption of common shares.*

STATEMENTS OF CASH FLOWS:

3 months ended September 30	**2002**	*2001*	*Explanation*
Cash and cash equivalents, beginning of period	**$ 150.5**	*$ 42.1*	
Provided by (used in):			
Operating activities	**(14.2)**	65.8	*Lower cash operating earnings in addition to $49.9 million payment to Alberta Power Pool related to ancillary services revenue settlement and timing of income tax payments.*
Investing activities	**(47.3)**	(347.1)	*In 2002, collection of amounts receivable from Aquila (formerly UtiliCorp) related to sale of the discontinued Alberta D&R operation in 2000 ($180.3 million), offset by lower capital expenditures relating to the construction of the Sarnia, Big Hanaford, Campeche and Chihuahua plants.* *In 2001, capital expenditures also included the installation of the scrubber at the Centralia plant.*
Financing activities	**27.5**	303.8	*In 2002, the issuance of US$63.0 million of commercial paper as a hedge of U.S. operations, partially offset by the repurchase of $16.5 million in common shares and the payment of $28.3 million in common share dividends.* *In 2001, higher net debt issuances of $497.0 million were used to fund capital expenditures, offset by common share dividends of $40.4 million and rthe redemption of preferred shares for $122.1 million.*
Translation of foreign currency cash	**4.1**	(3.1)	
Cash and cash equivalents, end of period	**$ 120.6**	$ 61.5	

9 months ended September 30	**2002**	2001	Explanation
Cash and cash equivalents, beginning of period	**$ 62.0**	$ 53.8	
Provided by (used in):			
Operating activities	**248.2**	583.9	*Lower cash operating earnings as a result of the impact of the Wabamun arbitration and prior period regulatory decisions, timing of ancillary revenue settlement, timing of accounts receivable relating to the Alberta Power Pool for Generation due to deregulation on Jan. 1, 2001 ($170.0 million), the final instalment of 2001 income taxes paid in the first quarter of 2002 ($109.0 million) and the timing of income tax payments, offset by the collection of the Transmission receivables ($31.7 million).*
Investing activities	**224.8**	(710.8)	*In 2002, proceeds on the disposal of the Transmission operation and collection of amounts receivable from Aquila (formerly UtiliCorp) related to the sale of the discontinued Alberta D&R operation in 2000, offset by*

			capital expenditures relating to the construction of the Sarnia, Big Hanaford, Campeche and Chihuahua plants as well as installation of the scrubber at the Centralia plant during the second quarter. *In 2001, capital expenditures relating primarily to the installation of the scrubber at the Centralia plant and construction of the Sarnia and Campeche plants were offset by proceeds on the disposal of the Edmonton Composter and the Mildred Lake and Fort Nelson plants.*
Financing activities	**(417.6)**	137.8	*In 2002, the issuance of US$300.0 million in long-term bonds and the proceeds on the sale of the Transmission operation discussed above offset by the repayment of long-term commercial paper, short-term debt and the payment of common share and preferred securities distributions.* *In 2001, long-term borrowings were used primarily to repay short-term debt, fund capital expenditures and to finance the redemption of preferred shares for $122.1 million.*
Translation of foreign currency cash	**3.2**	(3.2)	
Cash and cash equivalents, end of period	**$ 120.6**	$ 61.5	

OUTLOOK

The key factors affecting the financial results for 2002 continue to be the availability of and production from generating assets, the pricing applicable to non-contracted production and the costs of production.

Availability and production for the remainder of the year is expected to be consistent with the first nine months of the year. The 248 MW gas-fired Big Hanaford plant will be available for production in the fourth quarter of 2002, however actual production will be dependent on a recovery in spark spreads. The 650 MW Sarnia, Ontario plant is scheduled to commence commercial operations in the first quarter of 2003.

Electricity spot prices and spark spreads are expected to continue at their current level for the fourth quarter and into 2003. Expected electricity demand compared to levels of supply is expected to prevent prices from materially increasing over the medium term. TransAlta is continuing its focus on reducing fuel and OM&A expenses. The areas for reductions were identified in the fourth quarter of 2001, and have been and continue to be implemented. The benefits of these initiatives are beginning to be realized, and are expected to become fully apparent in 2003 and beyond.

Energy Marketing anticipates that short-term markets will continue to be active. Liquidity in the medium- and longer-term markets has decreased, however there is a need for the types of products offered in these markets and we expect that additional creditworthy counterparties will begin to emerge and thereby increase liquidity.

Assets under construction at Sept. 30, 2002 totalled $1,125.3 million and consisted primarily of the Sarnia plant discussed above and the 252 MW Campeche and 259 MW Chihuahua plants in Mexico, which are scheduled to commence commercial operations in the first and third quarter of 2003, respectively.

In February 2002, the EUB approved the previously announced 900 MW expansion of the Keephills plant. TransAlta is now updating its feasibility study, factoring in the impact of Alberta's transmission constraints, environmental conditions placed on the approval by the EUB and market conditions. The corporation expects to announce its decision by the end of 2002.

In May 2002, TransAlta and EPCOR Utilities Inc. (EPCOR) entered into a preliminary Memorandum of Understanding to jointly develop the Keephills project and negotiate the purchase of a 50 per cent interest in EPCOR's Genesee 3 project. The negotiations will also include an option for EPCOR to purchase a 50 per cent interest in TransAlta's Sarnia plant and the purchase of output from a recent capacity expansion at the Sundance generation facility. Negotiations are expected to be completed by the end of 2002.

TransAlta will continue to focus on exploring strategic acquisitions. The corporation believes its strong balance sheet will enable the corporation to take advantage of an increasing number of attractively priced asset acquisition opportunities to grow capacity.

The Canadian government has indicated its intention to ratify the Kyoto Protocol. TransAlta is not able to estimate the full impact the ratification will have on its business, as the government has not yet established an implementation plan. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change in Law' provisions which provide an opportunity to recover compliance costs from the PPA customers. As a member of the Canadian Clean Power Coalition, TransAlta, along with its peers, is exploring other means to reduce greenhouse gas emissions. TransAlta has an internal target to reduce net Canadian emissions to zero by 2024.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

(in millions of Canadian dollars except per share amounts)

	Unaudited		**Unaudited**	
	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Revenues	**$450.3**	$573.3	**$1,206.3**	$ 1,885.0
Fuel and purchased power	**(173.2)**	(250.5)	**(476.7)**	(984.2)
Gross margin	**277.1**	322.8	**729.6**	900.8

Operating expenses				
Operations, maintenance and administration	**98.4**	147.8	**285.4**	359.9
Depreciation and amortization	**53.1**	105.7	**156.5**	198.4
Taxes, other than income taxes	**6.0**	4.1	**19.8**	14.1
	157.5	257.6	**461.7**	572.4
Operating income	**119.6**	65.2	**267.9**	328.4
Other income (expense)	**(1.5)**	0.4	**(0.9)**	0.3
Foreign exchange gain (loss)	**(1.0)**	(2.0)	**0.3**	(2.1)
Net interest expense	**(20.9)**	(12.4)	**(58.7)**	(75.7)
Earnings from continuing operations before regulatory decisions,				
income taxes and non-controlling interests	**96.2**	51.2	**208.6**	250.9
Prior period regulatory decisions *(Note 8)*	**-**	-	**(3.3)**	-
Earnings from continuing operations before income taxes				
and non-controlling interests	**96.2**	51.2	**205.3**	250.9
Income taxes	**19.2**	10.8	**53.2**	89.4
Non-controlling interests	**3.6**	3.7	**14.5**	15.6
Earnings from continuing operations	**73.4**	36.7	**137.6**	145.9
Earnings from discontinued operations *(Note 2)*	**-**	8.0	**12.8**	31.8
Gain on disposal of discontinued operations *(Note 2)*	**-**	-	**110.0**	-
Net earnings	**73.4**	44.7	**260.4**	177.7
Preferred securities distributions, net of tax	**5.5**	3.3	**16.2**	9.6
Net earnings applicable to common shareholders	**$ 67.9**	$ 41.4	**$ 244.2**	$ 168.1
Common share dividends	**(42.1)**	(41.8)	**(126.7)**	(126.7)
Adjustment arising from normal course issuer bid	**(4.1)**	(9.9)	**(27.0)**	(20.7)
Retained earnings				
Opening balance	**907.1**	857.9	**838.3**	826.9
Closing balance	**$ 928.8**	$ 847.6	**$ 928.8**	$ 847.6
Weighted average common shares outstanding in the period	**169.2**	168.8	**169.5**	168.8
Basic earnings per share				
Continuing operations	**$ 0.40**	$ 0.20	**$ 0.72**	$ 0.81

Earnings from discontinued operations	**-**	0.05	**0.07**	0.19
Net earnings from operations	**0.40**	0.25	**0.79**	1.00
Net gain on disposal of discontinued operations	**-**	-	**0.65**	-
Net earnings	**$ 0.40**	$ 0.25	**$ 1.44**	$ 1.00
Diluted earnings per share				
Earnings from continuing operations	**$ 0.40**	$ 0.20	**$ 0.72**	$ 0.79
Earnings from discontinued operations	**-**	0.05	**0.07**	0.19
Net earnings from operations	**0.40**	0.25	**0.79**	0.98
Net gain on disposal of discontinued operations	**-**	-	**0.65**	-
Net earnings	**$ 0.40**	$ 0.25	**$ 1.44**	$ 0.98

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of Canadian dollars)

	Unaudited		Unaudited	
	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Operating activities				
Net earnings	**$ 73.4**	$ 44.7	**$ 260.4**	$ 177.7
Depreciation and amortization	**73.2**	135.6	**235.1**	296.2
Non-controlling interests	**3.6**	3.7	**14.5**	15.6
Loss (gain) on sale of assets	**0.3**	(8.5)	**3.3**	(7.5)
Site restoration costs incurred	**(9.0)**	(6.3)	**(12.1)**	(10.2)
Future income taxes (recovery)	**(34.4)**	15.3	**(16.6)**	6.7
Unrealized (gain) loss from energy marketing activities	**0.3**	(25.6)	**5.0**	(12.3)
Gain on disposal of Transmission operation	**-**	-	**(110.0)**	-
Other non-cash items	**(4.5)**	8.6	**(7.6)**	10.2
	102.9	167.5	**372.0**	476.4
Change in non-cash operating working capital balances	**(117.1)**	(101.7)	**(123.8)**	107.5
Cash flow from (used in) operating activities	**(14.2)**	65.8	**248.2**	583.9
Investing activities				

Additions to capital assets	**(182.2)**	(357.7)	**(751.2)**	(827.5)
Acquisitions	**-**	-	**-**	(9.8)
Proceeds on sale of discontinued operations	**-**	44.1	**818.0**	201.4
Long-term receivables	**136.0**	(32.2)	**170.7**	(66.6)
Long-term investments	**(0.5)**	-	**(6.1)**	-
Other	**(0.6)**	(1.3)	**(6.6)**	(8.3)
Cash flow from (used in) investing activities	**(47.3)**	(347.1)	**224.8**	(710.8)
Financing activities				
Net increase (decrease) in short-term debt	**1.4**	425.4	**(536.4)**	69.7
Issuance of long-term debt	**92.1**	91.7	**612.5**	664.9
Repayment of long-term debt	**(3.5)**	(20.1)	**(306.3)**	(291.9)
Redemption of preferred shares of a subsidiary	**-**	(122.1)	**-**	(122.1)
Issuance of common shares	**0.2**	2.0	**1.8**	14.0
Redemption of common shares	**(16.5)**	(16.2)	**(49.9)**	(30.2)
Distributions on preferred securities	**(9.1)**	(5.5)	**(26.7)**	(17.2)
Dividends on common shares	**(28.3)**	(40.4)	**(86.0)**	(120.9)
Deferred financing charges	**(2.3)**	-	**(7.6)**	-
Dividends to subsidiary's non-controlling preferred shareholders	**-**	(3.3)	**-**	(8.3)
Distributions to subsidiary's non-controlling limited partner	**(6.5)**	(7.7)	**(19.0)**	(20.3)
Other	**-**	-	**-**	0.1
Cash flow from (used in) financing activities	**27.5**	303.8	**(417.6)**	137.8
Cash flow from (used in) operating, investing and financing activities	**(34.0)**	22.5	**55.4**	10.9
Effect of translation on foreign currency cash	4.1	(3.1)	**3.2**	(3.2)
Increase (decrease) in cash and cash equivalents	**(29.9)**	19.4	**58.6**	7.7
Cash and cash equivalents, beginning of period	**150.5**	42.1	**62.0**	53.8
Cash and cash equivalents, end of period	**$ 120.6**	$ 61.5	**$ 120.6**	$ 61.5

See accompanying notes.

TRANSALTA CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of Canadian dollars)	**Sept. 30 2002 (Unaudited)**	Dec. 31 2001 (Audited*)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 120.6**	$ 62.0
Accounts receivable and other	**400.6**	625.3
Price risk management assets *(Note 3)*	**139.2**	137.6
Future income tax assets	**18.1**	16.9
Income taxes receivable	**199.4**	128.3
Materials and supplies at average cost	**112.1**	85.5
	990.0	1,055.6
Investments *(Note 4)*	**44.9**	37.3
Long-term receivables *(Note 5)*	**118.4**	221.4
Property, plant and equipment *(Note 2)*		
Cost	**8,083.1**	8,766.7
Accumulated depreciation	**(2,069.5)**	(2,671.9)
	6,013.6	6,094.8
Goodwill	**29.3**	29.3
Future income tax assets	**51.4**	15.6
Price risk management assets *(Note 3)*	**79.8**	71.3
Other assets	**70.0**	47.1
Total assets	**$ 7,397.4**	$ 7,572.4
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term debt	**$ 1.5**	$ 537.2
Accounts payable and accrued liabilities	**511.4**	627.5
Price risk management liabilities *(Note 3)*	**135.7**	114.1
Future income tax liabilities	**0.4**	11.8
Dividends payable	**42.7**	42.8
Current portion of long-term debt	**105.2**	104.3
	796.9	1,437.7
Long-term debt *(Note 6)*	**2,732.5**	2,406.8
Deferred credits and other long-term liabilities	**553.0**	526.5

Future income tax liabilities	**390.3**	409.1
Price risk management liabilities *(Note 3)*	**82.3**	69.0
Non-controlling interests	**277.2**	281.0
Preferred securities	**452.0**	452.6
Common shareholders' equity		
Common shares *(Note 7)*	**1,201.9**	1,170.9
Retained earnings	**928.8**	838.3
Cumulative translation adjustment	**(17.5)**	(19.5)
	2,113.2	1,989.7
Total liabilities and shareholders' equity	**$ 7,397.4**	$ 7,572.4
Contingencies *(Note 9)*		

See accompanying notes.

* Derived from the audited Dec. 31, 2001 consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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

1. Accounting policies

These interim consolidated financial statements do not include all of the disclosures included in the corporation's annual consolidated financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the corporation's most recent annual consolidated financial statements.

The accounting policies used in the preparation of these interim consolidated financial statements conform with those used in the corporation's most recent annual consolidated financial statements, except for accounting for goodwill, stock-based compensation, exchange gains and losses on translation of long-term foreign currency denominated monetary items and the presentation of energy-trading activities.

Effective Jan. 1, 2002, the corporation prospectively adopted the new Canadian Institute of Chartered Accountants (CICA) standard for goodwill and other intangibles. Under the new standard, goodwill and certain intangibles are no longer subject to amortization, but are instead tested for impairment at least annually. The adoption of this standard resulted in the reclassification of $29.3 million from acquired intangibles to goodwill, which will no longer be subject to amortization under the new standard. There was no impairment of goodwill upon adoption of this standard.

Net income and earnings per share for the three and nine months ended Sept. 30, 2001 adjusted to exclude the amortization of the above amount are as follows:

	3 months ended Sept. 30, 2001	9 months ended Sept. 30, 2001
Reported net earnings applicable to common shareholders	$ 41.4	$ 168.1
Amortization of acquired intangibles	2.3	5.4
Adjusted net earnings applicable to common shareholders	$ 43.7	$ 173.5
Reported basic earnings per share	$ 0.25	$ 1.00
Amortization of acquired intangibles per share	0.01	0.03
Adjusted basic earnings per share	$ 0.26	$ 1.03
Reported diluted earnings per share	$ 0.25	$ 0.98
Amortization of acquired intangibles per share	0.01	0.03
Adjusted diluted earnings per share	$ 0.26	$ 1.01

On Jan. 1, 2002, the corporation retroactively adopted the new CICA standard for stock-based compensation. The new standard requires that stock-based payments to non-employees, direct awards of stock and awards that call for settlement in cash or other assets be accounted for using the fair value method of accounting. The fair value method is encouraged for other stock-based compensation plans, but other methods of accounting, such as the intrinsic value method, are permitted. Under the fair value method, compensation expense is measured at the grant date and recognized over the service period. Under the intrinsic value method, compensation expense is determined as the difference between the market price of the underlying stock and the exercise price of the equity instrument granted. If the intrinsic value method is used, disclosure is made of earnings and per share amounts as if the fair value method had been used. The corporation has elected to use the intrinsic value method of accounting for its fixed stock option plans and its performance stock option plan. Accordingly, no compensation cost has been recognized for these plans. The following table provides pro forma measures of net earnings and earnings per share had compensation expense been recognized based on the estimated fair value of the options on the grant date in accordance with the fair value method of accounting for stock-based compensation:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001

Reported net earnings applicable to common shareholders	**$ 67.9**	$ 41.4	**$ 244.2**	$ 168.1
Compensation expense	**1.0**	0.5	**2.7**	1.5
Pro forma net earnings applicable to common shareholders	**$ 66.9**	$ 40.9	**$ 241.5**	$ 166.6
Reported basic earnings per share	**$ 0.40**	$ 0.25	**$ 1.44**	$ 1.00
Compensation expense per share	**0.01**	-	**0.02**	0.01
Pro forma basic earnings per share	**$ 0.39**	$ 0.25	**$ 1.42**	$ 0.99
Reported diluted earnings per share	**$ 0.40**	$ 0.25	**$ 1.44**	$ 0.98
Compensation expense per share	**0.01**	-	**0.02**	0.01
Pro forma diluted earnings per share	**$ 0.39**	$ 0.25	**$ 1.42**	$ 0.97

Options were only granted in the first quarter of 2002. The estimated fair value of these stock options was determined using the binomial model using the following weighted average assumptions, resulting in a weighted-average fair value of $4.25 per option (2001 - $4.35):

	2002	2001
Risk-free interest rate	**5.9%**	5.4%
Expected hold period to exercise (years)	**7.0**	7.0
Volatility in the price of the corporation's shares	**28.3%**	28.2%

The accounting treatment for the corporation's performance share ownership plan remains unchanged from the year ended Dec. 31, 2001. Under this plan, compensation expense recognized in the three and nine months ended Sept. 30, 2002 was $2.1 million and $6.4 million, respectively (2001 - $1.2 million and $5.5 million, respectively).

The CICA amended its standard on foreign currency translation effective Jan. 1, 2002. The changes require that translation gains and losses arising on long-term foreign currency denominated monetary items be included in income in the current period. Previously, these gains and losses were to be amortized over the life of the related item. As TransAlta designates long-term foreign currency denominated items as hedges of net investments in foreign operations, all gains and losses arising on the translation of these items are deferred and included in the cumulative translation adjustment account in shareholders' equity, therefore this amendment has no impact on TransAlta.

In June 2002, the Emerging Issues Task Force (EITF) in the U.S. reached a consensus in EITF 02-3 that all mark-to-market gains and losses on energy trading contracts should be shown net in the statement of earnings whether or not settled physically, effective for financial statements issued for periods ending after July 15, 2002, with reclassification of prior periods presented. An entity should also disclose the gross transaction volumes for those energy trading contracts that are physically settled. TransAlta has adopted this standard for Canadian GAAP as well. Commencing in the quarter ended Sept. 30, 2002, TransAlta has presented all energy trading and marketing activities on a net basis in the consolidated statements of earnings and retained earnings.

TransAlta's results are seasonal in nature due to the nature of the electricity market and related fuel costs.

2. Discontinued operations

On July 4, 2001, the corporation signed a purchase and sale agreement for the disposal of its Transmission operation. Regulatory approval was received on March 28, 2002. On April 29, 2002, the Transmission operation was sold for proceeds of $821.0 million, of which $3.0 million remains outstanding. The proceeds excluded accounts receivable of $31.7 million, which were retained and collected by TransAlta, and accounts payable of $4.4 million. The disposal resulted in a gain on sale of $110.0 million ($0.65 per common share), net of income taxes of $32.9 million. The gain on disposal reflects management's best estimate. The final gain on sale will be adjusted to reflect actual amounts, which are expected to be finalized by Dec. 31, 2002.

On June 29, 2001, the corporation's composter facility in Edmonton, Alberta was sold for cash proceeds of $97.0 million, which approximated its book value.

For reporting purposes, the results of the Transmission and Edmonton Composter operations have been presented as discontinued operations in the statement of earnings.

	2002	2001
3 months ended Sept. 30	**Transmission**	Transmission
Revenues	**$ -**	$ 38.9
Operating expenses	**-**	(22.0)
Operating income	**-**	16.9
Net interest expense	**-**	(3.1)
Earnings before income taxes	**-**	13.8
Income taxes	**-**	5.8
Earnings from discontinued operations	**$ -**	$ 8.0

At Sept. 30, 2002, all of the corporation's discontinued operations had been sold. At Dec. 31, 2001, all of the corporation's discontinued operations had been sold with the exception of the Transmission operation. Balance sheet amounts are as follows:

	2002	2001		
			Edmonton	
9 months ended Sept. 30		Transmission	Composter	Total
	Transmission			
Revenues	**$ 55.8**	$ 128.3	$ 6.6	$ 134.9
Operating expenses	**(30.8)**	(65.5)	(5.4)	(70.9)
Operating income	**25.0**	62.8	1.2	64.0
Net interest expense	**(2.4)**	(9.1)	-	(9.1)

Earnings before income taxes	**22.6**	53.7	1.2	54.9
Income taxes	**9.8**	22.6	0.5	23.1
Earnings before gain from discontinued operations	**12.8**	31.1	0.7	31.8
Gain on disposal	**110.0**	-	-	-
Earnings from discontinued operations	**$ 122.8**	$ 31.1	$ 0.7	$ 31.8

3. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES

The Energy Marketing group uses energy derivatives, including physical and financial swaps, forwards and options to gain market information, optimize returns from assets and to earn trading revenues. Trading activities are accounted for at fair value in accordance with Canadian and U.S. GAAP (EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*). Similar products are used to hedge the corporation's exposure to changes in electricity and natural gas prices. Under Canadian GAAP, settlement accounting is used for hedging activities if certain criteria are met. Under U.S. GAAP, hedging activities are accounted for in accordance with FASB Statement 133, *Accounting for Derivative Instruments and Hedging Activities*.

Energy Marketing's price risk management assets and liabilities represent the fair value of unsettled (unrealized) trading transactions:

	Sept. 30, 2002	**Dec. 31, 2001**
Current assets	**$ -**	$ 36.1
Capital assets	**-**	637.5
Other assets	**-**	3.3
Current liabilities	**-**	(15.5)
Net assets	**$ -**	$ 661.4

The following table illustrates movements in the fair value of the corporation's price risk assets and liabilities during the nine months ended Sept. 30, 2002:

Fair value of net price risk management assets outstanding at Dec. 31, 2001		**$ 25.8**
Fair value of new contracts entered into during the period	**13.0**	
Contracts realized or settled during the period	**(32.8)**	
Changes in fair values attributable to changes in valuation techniques and assumptions		**-**
Changes in fair values attributable to market price and other market changes		**(5.0)**
Fair value of net price risk management assets outstanding at Sept. 30, 2002		**$ 1.0**

The source of the valuations of the above contracts and maturities over each of the next five calendar years and thereafter is as follows:

	2002	2003	2004	2005	2006	2007 and thereafter	Total
Prices actively quoted	$ 0.9	**$ (6.8)**	**$ 0.8**	**$ 0.7**	**$ 0.8**	**$ 0.4**	**$ (3.2)**
Prices based on models	0.1	**4.1**	**-**	**-**	**-**	**-**	**4.2**
Asset (liability)	$ 1.0	**$ (2.7)**	**$ 0.8**	**$ 0.7**	**$ 0.8**	**$ 0.4**	**$ 1.0**

4. Investments

In January 2002, an additional $2.9 million was invested in a wind power generation company. This investment is accounted for using the equity method.

In April 2002, an additional $2.5 million was invested in a distributed generation company. This investment is accounted for using the equity method.

In April 2002, an initial $0.2 million was invested in a biomass generation company. An additional $0.5 million was invested in September 2002. The investment is accounted for using the cost method.

In addition, a foreign exchange revaluation of $1.5 million occurred during the nine months ended Sept. 30, 2002 on the investment in the Australian gas transmission pipeline.

5. LONG-TERM RECEIVABLES

In August 2002, the amount due from Aquila Networks Canada (formerly UtiliCorp Networks Canada) that arose from the August 2000 sale of the discontinued Alberta Distribution and Retail operation was collected in full.

The California accounts receivable have been reclassified to long-term, as collection is no longer expected in 2002, although ultimate collection is expected.

6. LONG-TERM DEBT

On June 20, 2002, the corporation issued debt of US$300.0 million under a US$1.0 billion shelf prospectus filed May 14, 2002. The notes are unsecured and bear interest at 6.75 per cent, and mature on July 15, 2012. Net proceeds on the issuance were $456.9 million.

In the third quarter of 2002, TransAlta issued US$63.0 million of commercial paper, which bears interest at a fixed rate of 1.75 per cent. Under the terms of TransAlta's credit facility, the corporation has the ability and intent to maintain these commercial paper borrowings beyond one year.

7. Common shares issued and outstanding

TransAlta Corporation is authorized to issue an unlimited number of voting common shares without nominal or par value. At Sept. 30, 2002, the corporation had 168.4 million (Dec. 31, 2001 - 168.3 million) common shares issued and outstanding plus outstanding employee stock options to purchase an additional 3.4 million shares (Dec. 31, 2001 - 2.8 million).

In February 2002, TransAlta announced a normal course issuer bid to repurchase up to 3.0 million common shares for cancellation. In the nine months ended Sept. 30, 2002, 1.9 million common shares have been repurchased under normal course issuer bids.

8. PRIOR PERIOD REGULATORY DECISION

Financial results for 2002 were affected by Alberta Energy and Utilities Board (EUB) decisions related to other reporting periods. The impact of such regulatory decisions is recorded when the effect of such decisions is known, without adjustment to the financial statements of prior periods.

On April 16, 2002, the EUB rendered a negative decision of $3.3 million with respect to TransAlta's hydro bidding strategy in 2000.

9. contingencies

In August 2000, a single thermal generating unit at the Wabamun plant was shut down due to safety concerns related to possible corrosion fatigue cracks within the waterwall tubing of its boiler. Repairs were completed late in the second quarter of 2001 and the unit returned to service in June 2001.

Since Jan. 1, 2001, the unit has been subject to the terms of a power purchase arrangement (PPA). Under the PPA's *force majeure* article, the corporation is not obligated to supply electricity during the period of repair, subject to confirmation by the administrator of the PPAs. Had such confirmation not occurred, the corporation would have been obligated to pay a penalty equal to the cost of obtaining an alternative source of electricity to fulfill its PPA supply obligations during the affected period. The *force majeure* decision went to arbitration in July 2001. On May 23, 2002, the arbitrators confirmed in their ruling that the outage qualified as a *force majeure* event, but also ruled that the corporation should have returned the unit to service more quickly. As a result of the decision, the corporation was required to pay $38.9 million plus interest of $2.7 million.

On May 8, 2002, the U.S. Federal Energy Regulatory Commission (FERC) requested that 150 sellers of wholesale electricity and ancillary services to the California electricity market, including TransAlta, respond to

questions regarding their trading strategies in California during 2000 and 2001. TransAlta has responded to the FERC request and believes it operated in accordance with all applicable laws, rules, regulations and tariffs.

On May 21 and 22, 2002, FERC issued two additional requests for information regarding 'round-trip' trading activities, to which TransAlta responded, stating that the corporation does not believe it participated in any round-trip trades during 2000 and 2001. In addition, Reliant Energy Inc. issued a statement that it engaged in round-trip trades in 1999 with Merchant Energy Group of the Americas, Inc. (MEGA). TransAlta acquired an initial 50 per cent interest in MEGA in June 2000, and acquired the remaining 50 per cent in June 2001. TransAlta contends that no round-trip trading occurred between Reliant Energy Inc. and MEGA during any period in which TransAlta had an ownership interest in MEGA. TransAlta will continue to cooperate with the regulators and supply all information requested.

On May 30, 2002, the California Attorney General's Office (CAGO) filed civil complaints in the state court of California against eight additional wholesale power companies, including TransAlta. The complaint alleges violations of California's unfair business practices law in connection with rates charged for wholesale electricity sales. TransAlta believes that it has complied with applicable laws in regard to this complaint. In particular, the company is of the view that the basis of the complaint is a matter of federal rather than state jurisdictions. In this regard, the company notes that FERC has previously rejected allegations made by CAGO that TransAlta's subsidiaries violated rate filing requirements. On June 26, 2002, TransAlta filed a Notice of Motion to dismiss the complaint.

On Sept. 9, 2002, the Commodities Futures Trading Commission requested information on similar issues. TransAlta has provided the requested information.

The Canadian government has indicated its intention to ratify the Kyoto Protocol. TransAlta is not able to estimate the full impact the ratification will have on its business, as the government has not yet established an implementation plan. However, the PPAs for TransAlta's coal-fired plants in Alberta contain 'Change in Law' provisions provide an opportunity to recover compliance costs from the PPA customers.

10. Comparative figures

Certain comparative figures have been reclassified to conform with the current period's presentation.

11. SEGMENTED DISCLOSURES

Effective Jan. 1, 2002, the Generation and Independent Power Projects business segments were combined into one Generation segment to reflect changes in TransAlta's organizational structure. Prior period amounts have been reclassified.

A. Segment financial information

I) Earnings information

	Unaudited			
3 months ended Sept. 30, 2002	**Generation**	Energy	Corporate	**Totals**
Revenues	**$ 431.8**	$ 1,358.6	$ -	**$ 1,790.4**
Trading purchases	**-**	(1,340.1)	-	**(1,340.1)**
Net segment revenues	**431.8**	18.5	-	**450.3**
Fuel and purchased power	**(173.2)**	-	-	**(173.2)**
Gross margin	**258.6**	18.5	-	**277.1**
Operations, maintenance and administration	**76.9**	5.0	16.5	**98.4**
Depreciation and amortization	**48.2**	0.6	4.3	**53.1**
Taxes, other than income taxes	**5.9**	0.1	-	**6.0**
EBIT before corporate allocations	**127.6**	12.8	(20.8)	**119.6**
Corporate allocations	**(18.7)**	(2.1)	20.8	**-**
EBIT	**$ 108.9**	$ 10.7	$ -	**119.6**
Other expense				**(1.5)**
Foreign exchange loss				**(1.0)**
Net interest expense				**(20.9)**
Earnings from continuing operations before income taxes and non-controlling interests				$ 96.2

	Unaudited			
3 months ended Sept. 30, 2001	**Generation**	Energy	Corporate	**Totals**
Revenues	$ 527.8	$ 424.0	$ -	$ 951.8
Trading purchases	-	(378.5)	-	(378.5)
Net segment revenues	527.8	45.5	-	573.3
Fuel and purchased power	(250.5)	-	-	(250.5)
Gross margin	277.3	45.5	-	322.8
Operations, maintenance and administration		7.5	14.1	147.8
Depreciation and amortization	97.1	2.9	5.7	
Taxes, other than income taxes	4.1	-	-	4.1
EBIT before corporate allocations	49.9	35.1	(19.8)	65.2
Corporate allocations	(18.3)	(1.5)	19.8	-
EBIT	$ 31.6	$ 33.6	$ -	65.2
Other income				0.4
Foreign exchange loss				(2.0)
Net interest expense				(12.4)
Earnings from continuing operations before income taxes and non-controlling interests				$ 51.2

9 months ended Sept. 30, 2002	**Unaudited** **Generation**	Energy Marketing	Corporate	**Totals**
Revenues	**$ 1,175.2**	$ 2,711.4	$ -	**$ 3,886.6**
Trading purchases	**-**	(2,680.3)	-	**(2,680.3)**
Net segment revenues	**1,175.2**	31.1	-	**1,206.3**
Fuel and purchased power	**(476.7)**	-	-	**(476.7)**
Gross margin	**698.5**	31.1	-	**729.6**
Operations, maintenance and administration	**231.0**	11.5	42.9	**285.4**
Depreciation and amortization	**138.9**	2.0	15.6	**156.5**
Taxes, other than income taxes	**19.7**	0.1	-	**19.8**
Prior period regulatory decisions *(Note 8)*	**3.3**	-	-	**3.3**
EBIT before corporate allocations	**305.6**	17.5	(58.5)	**264.6**
Corporate allocations	**(52.5)**	(6.0)	58.5	-
EBIT	**$ 253.1**	$ 11.5	$ -	**264.6**
Other expense				**(0.9)**
Foreign exchange gain				**0.3**
Net interest expense				**(58.7)**
Earnings from continuing operations before income taxes and non-controlling interests				

9 months ended Sept. 30, 2001	**Unaudited** **Generation**	Energy Marketing	Corporate	**Totals**
Revenues	$ 1,726.6	$ 2,167.8	$ -	$ 3,894.4
Trading purchases	-	(2,009.4)	-	(2,009.4)
Net segment revenues	1,726.6	158.4	-	1,885.0
Fuel and purchased power	(984.2)	-	-	(984.2)
Gross margin	742.4	158.4	-	900.8
Operations, maintenance and administration	279.0	34.6	46.3	
Depreciation and amortization	174.1	7.0		198.4
Taxes, other than income taxes	14.1	-	-	14.1
EBIT before corporate allocations	275.2	116.8	(63.6)	328.4
Corporate allocations	(58.9)	(4.7)	63.6	-
EBIT	$ 216.3	$ 112.1	$ -	328.4
Other income				
Foreign exchange loss				(2.1)
Net interest expense				(75.7)
Earnings from continuing operations before income taxes and non-controlling interests				$ 250.9

II. Selected balance sheet information

		Energy		Discontinued	
Sept. 30, 2002	Generation	**Marketing**	**Corporate**	**Operations**	**Total**
Segment assets	$6,322.1	**$ 430.8**	**$ 644.5**	$ -	**$7,397.4**
Dec. 31, 2001 (audited)					
Segment assets	$ 5,862.9	$ 423.6	$ 609.0	$ 676.9	$ 7,572.4

III. Selected cash flow information

		Energy		Discontinued	
3 months ended Sept. 30, 2002	Generation	**Marketing**	**Corporate**	**Operations**	**Total**
Capital expenditures	$ 179.0	**$ 0.4**	**$ 2.8**	**$ -**	**$ 182.2**
3 months ended Sept. 30, 2001					
Capital expenditures	$ 323.1	$ 3.9	$ 19.4	$ 11.3	$ 357.7
9 months ended Sept. 30, 2002					
Capital expenditures	$ 718.3	**$ 2.1**	**$ 9.0**	**$ 21.8**	**$ 751.2**
9 months ended Sept. 30, 2001					
Capital expenditures	$ 732.1	$ 41.8	$ 21.4	$ 32.2	$ 827.5

IV. Reconciliation

Depreciation and amortization expense (D&A) per statement of cash flows

	3 months ended Sept. 30		**9 months ended Sept. 30**	
	2002	2001	**2002**	2001
D&A expense for reportable segments	**$ 53.1**	$105.7	**$ 156.5**	$ 198.4
Discontinued operations	**-**	9.7	**15.6**	33.6
Mining equipment depreciation, included in fuel and purchased power	**10.5**	9.0	**29.6**	27.8
Site restoration accrual, included in fuel and purchased power	**9.6**	10.2	**31.2**	31.2
Amortization of deferred financing charges and other	**-**	1.0	**2.2**	5.2
	$ 73.2	$135.6	**$ 235.1**	$ 296.2

12. United States generally accepted accounting principles

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP), which, in most material respects, conform to United States generally accepted accounting principles (U.S. GAAP). Significant differences between Canadian and U.S. GAAP are as follows:

A. EARNINGS AND EPS

		3 months ended Sept. 30		9 months ended Sept. 30	
	Notes	**2002**	2001	**2002**	2001
Earnings from continuing operations - Canadian GAAP		**$ 73.4**	$ 36.7	**$ 137.6**	$ 145.9
Derivatives and hedging activities, net of tax	*I*	**(5.4)**	0.5	**(2.2)**	0.9
Start-up costs, net of tax	*II*	**(0.9)**	0.8	**(4.2)**	2.6
Preferred securities distributions, net of tax	*III*	**(5.5)**	(3.3)	**(16.2)**	(9.6)
Amortization of debt extinguishment, net of tax	*IV*	**0.3**	0.3	**0.7**	0.7
Income taxes - rate change adjustment	*V*	**-**	-	**-**	20.0
Amortization of pension transition adjustment	*VI*	**(1.2)**	(1.2)	**(3.4)**	(3.4)
Earnings from continuing operations - U.S. GAAP		**$ 60.7**	$ 33.8	**$ 112.3**	$ 157.1
Earnings from discontinued operations - Canadian and U.S. GAAP		**$ -**	8.0	**12.8**	31.8
Net gain on disposal of discontinued operations - Canadian and U.S. GAAP		**-**	-	**110.0**	-
Net earnings before change in accounting principle - U.S. GAAP		**60.7**	41.8	**235.1**	188.9
Cumulative effect of change in accounting principle, net of taxes of $0.1 million	*I*	**-**	-	**-**	0.2
Net earnings - U.S. GAAP		**$ 60.7**	$ 41.8	**$ 235.1**	$ 189.1
Cumulative effect of change in accounting principle, net of taxes of $25.9 million	*I,VIII*	**-**	-	**-**	(38.5)
Foreign currency cumulative translation adjustment	*I,VIII*	**11.3**	13.0	**(8.3)**	(37.8)
Net gain (loss) on derivative instruments	*I,VIII*	**(28.2)**	(4.9)	**(32.7)**	1.3
Comprehensive income - U.S. GAAP		**$ 43.8**	$ 49.9	**$ 194.1**	$ 114.1
Basic EPS - U.S. GAAP					
Earnings from continuing operations		**$ 0.36**	$ 0.20	**$ 0.66**	$ 0.93
Earnings from discontinued operations		**-**	0.05	**0.07**	0.19
Net earnings from operations		**0.36**	0.25	**0.73**	1.12
Net gain on disposal of discontinued operations		**-**	-	**0.65**	-
Cumulative effect of change in accounting principle		**-**	-	**-**	-
Net earnings		**$ 0.36**	$ 0.25	**$ 1.38**	$ 1.12
Diluted EPS - U.S. GAAP					
Earnings from continuing operations		**$ 0.36**	$ 0.20	**$ 0.66**	$ 0.91

Earnings from discontinued operations	**-**	0.05	**0.07**	0.19
Net earnings from operations	**0.36**	0.25	**0.73**	1.10
Net gain on disposal of discontinued operations	**-**	**-**	**0.65**	-
Cumulative effect of change in accounting principle	**-**	-	**-**	-
Net earnings	**$ 0.36**	$ 0.25	**$ 1.38**	$ 1.10

B. Balance Sheets

		Sept. 30, 2002		Dec. 31, 2001 (Audited)	
	Notes	**Canadian GAAP**	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets					
Current derivative assets	*I*	**$ -**	$	$ -	$ 58.5
Accounts receivable	*IX*	**400.6**	398.9	625.3	624.0
Future or deferred income tax assets - current	*V*	**18.1**	18.1	16.9	25.6
Income taxes receivable	*I, II*	**199.4**	207.7	128.3	136.9
Investments	*X*	**44.9**	261.7	37.3	227.8
Property, plant and equipment, net	*II*	**6,013.6**	6,022.6	6,094.8	6,010.9
Other assets	*I, II, III, VI*	**70.0**	12.1	47.1	18.3
Long-term derivative asset	*I*	**-**	67.9	-	54.1
Liabilities					
Accounts payable and accrued liabilities	*VI*	**511.4**	466.0	627.5	580.7
Current derivative liability	*I*	**-**	0.8	-	21.5
Firm commitments	*I*	**-**	5.7	-	3.6
Long-term debt, including current portion	*I, III, X*	**2,837.7**	3,538.2	2,511.1	3,184.5
Deferred credits and other long-term liabilities	*I, IV*	**553.0**	519.2	526.5	498.7
Regulatory rate-making liability	*V*	**-**	-	-	8.7
Long-term derivative liabilities	*I*	**-**	164.4	-	134.3
Future or deferred income taxes	*I, II, III, IV, V, VI*	**390.3**	363.2	409.1	416.6
Equity					
Preferred securities	*III*	**452.0**	-	452.6	**-**
Common shares	IX	**1,201.9**	1,200.2	1,170.9	1,169.2
Retained earnings	*I, II, IV, V, VI*	**928.8**	939.8	838.3	858.4
Cumulative translation adjustment	*I, VIII*	**(17.5)**	-	(19.5)	-
Accumulated other comprehensive income	*I, VIII*	**-**	(94.7)	-	(53.7)

C. Reconciling items

I. Derivatives and hedging activities On Jan. 1, 2001, the corporation adopted Statement 133, Accounting for Derivative Instruments and Hedging Activities. The new statement requires all derivative instruments to be recorded on the balance sheet at fair value, with changes in fair value recognized in earnings in the period of change. If the derivative is designated as and qualifies as a fair value hedge, the changes in fair value of the derivative and the hedged item attributable to the hedged risk are recognized in earnings in the period the change occurs. If the derivative is designated as and qualifies as a cash flow hedge, the effective portion of changes in the fair value of the derivative is recorded in other comprehensive income (OCI) and is recognized in earnings as the hedged item affects earnings. The ineffective portion of changes in fair value of cash flow hedges is recognized in earnings. If the derivative is designated as and qualifies as a hedge of a net investment in a foreign currency, the effective portion of changes in fair value is recorded in cumulative translation adjustment (CTA) as part of OCI and the ineffective portion is recognized in earnings.

The adoption of Statement 133 on Jan. 1, 2001 resulted in the recognition of additional derivative assets with a fair value of $1.6 million, firm commitment assets with a fair value of $0.6 million, additional derivative liabilities with a fair value of $88.6 million, a $0.3 million ($0.2 million after-tax) credit to income as the cumulative effect of a change in accounting principle and a charge of $64.4 million ($38.5 million after-tax) to OCI as the cumulative effect of a change in accounting principle.

(i) **Fair value hedging strategy** The corporation enters into forward exchange contracts to hedge certain firm commitments denominated in foreign currencies to protect against adverse changes in exchange rates and uses interest rate swaps to manage interest rate exposure. The swaps modify exposure to interest rate risk by converting a portion of the corporation's fixed-rate debt to a floating rate.

In the three and nine months ended Sept. 30, 2002 and 2001, the corporation's fair value hedges resulted in net gains of $nil related to the ineffective portion of its hedging instruments (inclusive of the time value of money) as well as the portion of the hedging instrument excluded from the assessment of hedge effectiveness.

(ii) **Cash flow hedging strategy** The corporation uses forward-starting swaps, treasury locks and spread locks to hedge the interest rates of anticipated issuances of debt to protect the corporation against increases in interest rates prior to the date of issuance, and uses fixed for floating swaps to hedge generation production to protect the corporation against fluctuations in commodity prices. The maximum term of cash flow hedges of anticipated transactions is 13 years.

In the three and nine months ended Sept. 30, 2002, the corporation's cash flow hedges resulted in a net gain of $nil and $0.2 million, respectively, (2001 - $nil) related to the ineffective portion of its hedging instruments, and a net gain of $nil and $0.2 million, respectively, (2001 - $nil) related to the portion of the hedging instrument excluded from the assessment of hedge effectiveness.

In June 2002, forward starting swaps with a notional amount of US$125.0 million were settled and debt was issued, resulting in a loss of $11.2 million. The loss will be reclassified from OCI over ten years, the term of the hedged debt.

Over the next twelve months, the corporation expects to reclassify net losses of $1.0 million from OCI to net earnings that arose from cash flow hedges, and expects to reclassify approximately $6.1 million of net losses on cash flow hedging instruments that arose on adoption of statement 133 from accumulated other comprehensive income (AOCI) to earnings.

(iii) **Net investment hedges** The company uses cross-currency interest rate swaps, forward sales contracts and direct foreign currency debt to hedge its exposure to changes in the carrying value of its investments in its foreign subsidiaries in the U.S., Australia, Barbados and Mexico.

In the three and nine months ended Sept. 30, 2002, the corporation recognized a net after-tax gain of $11.3 million and a net after-tax loss of $8.3 million, respectively (2001 - $13.0 million net after-tax gain and $37.8 million net after-tax loss, respectively) on its net investment hedges, included in CTA, related to cross-currency interest rate swaps and forward sales contracts.

In the three and nine months ended Sept. 30, 2001, the corporation recognized income of $nil and $0.7 million, respectively (2001 - $nil), related to ineffectiveness of its net investment hedges.

(iv) **Trading activities** As disclosed in Note 20 to the corporation's most recent annual consolidated financial statements, the corporation uses energy derivatives including physical and financial swaps, forwards and options to gain market information, optimize returns from assets and to earn trading revenues. These derivatives are recorded on the balance sheet at fair value under both Canadian and U.S. GAAP (EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*).

(v) **Other hedging activities** In the three and nine months ended Sept. 30, 2002, the corporation recognized a loss of $4.3 million and $3.1 million, respectively (2001 - losses of $4.1 million and $10.5 million, respectively) related to hedging activities that do not qualify for hedge accounting treatment under Statement 133.

II. Start-up costs Under U.S. GAAP, certain start-up costs, including revenues and expenses in the pre-operating period, are expensed rather than capitalized to deferred charges and capital assets as under Canadian GAAP, which also results in decreased depreciation and amortization expense under U.S. GAAP.

III. Preferred securities Under U.S. GAAP, the corporation's preferred securities are considered to be entirely debt with no equity component, whereas under Canadian GAAP, these preferred securities have both a debt and equity component. Accordingly, the preferred security distributions are classified as an expense under U.S. GAAP rather than a direct charge to retained earnings. Under U.S. GAAP, the costs associated with the issuance of the preferred securities are recorded as an asset whereas under Canadian GAAP, these costs, net of tax, are charged to preferred securities.

IV. Debt extinguishment Under U.S. GAAP, the premium on redemption of long-term debt related to the limited partnership transaction, as described in Note 12 to the corporation's most recent annual consolidated financial statements, was recorded as an extraordinary loss when it occurred, whereas for Canadian GAAP the loss is amortized to earnings over the period of the limited partnership to 2018.

V. Income taxes Future income taxes under Canadian GAAP are referred to as deferred income taxes under U.S. GAAP. Canadian and U.S. GAAP require accounting for income taxes using the liability method of tax allocation; however, two significant differences remain between Canadian and U.S. GAAP:

i. Canadian GAAP requires that future income tax balances be adjusted to reflect substantively enacted rates rather than currently legislated tax rates under U.S. GAAP. As a result of this difference, a $20.0 million adjustment to earnings from continuing operations was required in 2001; and

ii. Under Canadian GAAP, rate-regulated operations need not recognize future income taxes to the extent that future income taxes are expected to be included in the rates charged to and recovered from customers. For these operations, U.S. GAAP requires that the corporation record deferred income tax assets or liabilities for its rate-regulated operations. As these amounts are recoverable or payable through future revenues, a corresponding regulatory asset or liability is recorded for U.S. GAAP purposes.

Deferred income taxes under U.S. GAAP would be as follows:

	Sept. 30, 2002	Dec. 31, 2001 (Audited)
Future income tax liability (net) under Canadian GAAP	**$ (321.2)**	$ (388.4)
Rate-regulated operations deferred income taxes	**-**	8.7
Derivatives	**44.2**	15.6
Start-up costs	**(2.3)**	(2.3)
Preferred securities	**(6.0)**	(6.2)
Debt extinguishment	**9.7**	9.7
Employee future benefits	**(18.5)**	(24.3)
	$ (294.1)	$ (387.2)
Comprised of the following:		
Current deferred income tax assets	**$ 18.1**	$ 25.6
Long-term deferred income tax assets	**51.4**	15.6
Current deferred income tax liabilities	**(0.4)**	(11.8)
Long-term deferred income tax liability	**(363.2)**	(416.6)

	$ (294.1)	$ (387.2)

VI. Employee future benefits U.S. GAAP requires that the cost of employee pension benefits be determined using the accrual method with application from 1989. It was not feasible to apply this standard using this effective date. The transition asset as at Jan. 1, 1998 was determined in accordance with elected practice prescribed by the Securities and Exchange Commission and is amortized over ten years. The difference between U.S. GAAP and Canadian GAAP for the corporation's regulated operations had no effect on net earnings and retained earnings, as any difference from the allowed method of recovery is recognized as a regulatory liability refundable through regulation. As indicated in Note 4 to the annual consolidated financial statements, the corporation discontinued regulatory accounting and commenced the application of Canadian GAAP consistent with the deregulation of the electricity generation industry in Alberta beginning Jan. 1, 2001.

Sensitivity to changes in assumed health care cost trend rates at Dec. 31, 2001 are as follows:

	One percentage point increase	One percentage point decrease
Effect on total service and interest costs	0.1	(0.1)
Effect on post-retirement benefit obligation	0.6	(0.6)

VII. Joint ventures In accordance with Canadian GAAP, joint ventures are required to be proportionately consolidated regardless of the legal form of the entity. Under U.S. GAAP, incorporated joint ventures are required to be accounted for by the equity method. However, in accordance with practices prescribed by the SEC, the corporation, as a Foreign Private Issuer, has elected for the purpose of this reconciliation to account for incorporated joint ventures by the proportionate consolidation method.

VIII. Other comprehensive income

The changes in the components of OCI were as follows:

	3 months ended Sept. 30		9 months ended Sept. 30	
	2002	2001	**2002**	2001
Cumulative effect of accounting change, net of taxes of ($25.9) million	**$ -**	$ -	**$ -**	$ (38.5)
Net gain on derivative instruments:				
Unrealized gain (loss), net of taxes of ($19.3) million and ($23.6) million (2001 -	**(29.0)**	(7.4)	**(35.4)**	(5.9)

Reclassification from OCI to net income, net of taxes of $0.5 million and $1.8 million (2001 - $1.7 million and $4.8 million)	**0.8**	2.5	**2.7**	7.2
Net gain (loss) on derivative instruments	**(28.2)**	(4.9)	**(32.7)**	1.3
Translation adjustments	**11.3**	13.0	**(8.3)**	(37.8)
Other comprehensive income (loss)	**$ (16.9)**	$ 8.1	**$ (41.0)**	$ (75.0)

The components of accumulated other comprehensive income are

	Sept. 30, 2002	Dec. 31, 2001
Net loss on derivative instruments	**$ (61.2)**	$ (28.5)
Translation adjustments	**(33.5)**	(25.2)
Accumulated other comprehensive loss	**$ (94.7)**	$ (53.7)

IX. SHARE CAPITAL ***Under U.S. GAAP, amounts receivable for share capital should be recorded as a deduction from shareholder's equity. Under the corporation's employee share purchase plan, accounts receivable for share purchases at Sept. 30, 2002 was $1.7 million (Dec. 31, 2001 - $1.7 million).***

X. RIGHT OF OFFSET AGREEMENT ***As disclosed in Notes 6 and 11 to the annual consolidated financial statements, the corporation has a UK bank deposit that has been offset with a New Zealand bank facility. The arrangement does not qualify for offsetting under U.S. GAAP.***

D. DILUTED EARNINGS PER SHARE

Diluted earnings per share has been calculated after giving rise to the dilutive effect of the exercise of stock options, which would increase the weighted average number of common shares outstanding by nil for the three and nine months ended Sept. 30, 2002 (2001 - nil and 0.2 million). The dilutive impact of PSOP would result in an increase in compensation expense of $nil for the three and nine months ended Sept. 30, 2002 (2001 - $2.6 million), and an increase in the weighted average number of common shares outstanding of 0.3 million for the three and nine months ended Sept. 30, 2002 (2001 - 0.6 million).

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TransAlta Corporation

(Registrant)

By:/s/ Alison T. Love

(Signature)

Alison T. Love, Corporate Secretary

Date: October 17, 2002

CERTIFICATIONS

I, Stephen G. Snyder, certify that:

1. I have reviewed this Report of Foreign Private Issuer on Form 6-K of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the "Evaluation Date"); and

c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weakness in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: October 17, 2002 /s/ Stephen G. Snyder

Stephen G. Snyder

President and Chief Executive Officer

I, Ian Bourne, certify that:

1. I have reviewed this Report of Foreign Private Issuer on Form 6-K of TransAlta Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this report (the "Evaluation Date"); and

c) presented in this report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weakness in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officer and I have indicated in this report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: October 17, 2002 /s/ Ian Bourne

Ian Bourne

Executive Vice President and Chief Financial Officer