Attachment 3

Alberta Energy Company Ltd.

Management's Discussion and Analysis
March 31, 2002

Management's Discussion and Analysis of Financial Condition

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing Alberta Energy Company Ltd. ("AEC" or the "Company") shareholders and potential investors with information regarding the Company, certain statements throughout this Management's Discussion and Analysis (the "MD&A") contains certain forward-looking statements within the meaning of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements are typically identified by words such as "anticipate," "believe," "expect," "plan," "intend," or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company's operating costs, the Company's seismic and drilling plans, oil and gas prices, per unit netbacks, the Company's oil, liquids and gas sales, the Company's cash flow from operations and net earnings, the Company's production levels, the Company's share of Syncrude production, development plans with respect to the Company's Foster Creek SAGD commercial project, the timing of the closing of the sale of the Company's Colombian assets, the impact of hedges on the Company's revenue in a low price environment, capital investment levels, the sources of funding for capital investments, the successful integration of the Company's personnel and businesses with those of PanCanadian Energy Corporation ("PanCanadian") and the timing thereof, and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although AEC believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration, development and drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates including Ecuador, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission (the "SEC"). Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which is as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Management's discussion and analysis of the financial condition and results of operations is to be read in conjunction with the Interim Unaudited Consolidated Financial Statements at and for the three months ended March 31, 2002 and Management's Discussion and Analysis and Audited Consolidated Financial Statements at and for the year ended December 31, 2001.

SUBSEQUENT EVENT

On April 5, 2002, AEC and PanCanadian announced the completed merger of their two companies, creating EnCana Corporation ("EnCana"). The Court of Queen's Bench of Alberta approved the plan of arrangement involving AEC, one day after shareholders and optionholders of AEC and shareholders of PanCanadian voted 91% and 81%, respectively, in favor of the transaction. PanCanadian shareholders also approved changing PanCanadian's name to EnCana Corporation. Under the terms of the merger, AEC shareholders received 1.472 PanCanadian (EnCana after the name change) common shares for each AEC common share they owned.

CONSOLIDATED SUMMARY

Consolidated Net Earnings for the three months ended March 31, 2002 amounted to $72.0 million, a 78% decrease, or $0.37 per share, diluted ("per share") compared to $332.6 million, or $2.03 per share, in 2001 (2000 - $118.8 million; $0.79 per share).

Consolidated Cash Flow from Operations decreased 50% to $405.8 million for the first three months of 2002, or $2.58 per share, from $809.3 million, or $5.13 per share, in 2001 (2000 - $367.2 million; $2.56 per share). Consolidated Revenues, net of royalties and production taxes, totaled $1,226.3 million in the first quarter of 2002, compared to $2,088.8 million in 2001, a 41% decrease (2000 - $1,019.0 million).

Consolidated Financial Summary		First Quarter	
($ million)	2002	2001	2000
Net Earnings	72.0	332.6	118.8
Cash Flow from Operations	405.8	809.3	367.2
Revenues, net of royalties and production taxes	1,226.3	2,088.8	1,019.0
Diluted per Share ($ per share)			
Net Earnings	0.37	2.03	0.79
Cash Flow from Operations	2.58	5.13	2.56

Consolidated Net Revenues decreased primarily as a result of lower natural gas prices and lower Purchased Gas sales in the first quarter of 2002 compared to the same period in 2001. This decrease was partially offset by higher produced natural gas volumes sold. Cash Flow from Operations reflects lower produced gas netbacks, partially offset by lower cash Income Taxes. Net Earnings includes the impact of higher Deprecation, Depletion and Amortization as a result of the higher produced natural gas and crude oil volumes sold and lower future Income Taxes. Interest, net, increased due to higher average long term debt levels.

Contributions for the past eight quarters are as noted in the following table:

Quarterly Information

($ million except per share amounts)

Year Quarter	2002 Q1	2001 Q4	2001 Q3	2001 Q2	2001 Q1	2000 Q4	2000 Q3	2000 Q2
Revenues, net of royalties and production taxes	1,226.3	1,206.4	1,339.2	1,637.9	2,088.8	2,067.2	1,364.7	1,072.8
Net Earnings	72.0	79.8	144.2	267.2	332.6	468.8	222.8	111.6
- per share basic	0.38	0.47	0.90	1.70	2.15	3.12	1.51	0.75
- per share diluted	0.37	0.46	0.87	1.62	2.03	2.97	1.48	0.73
Cash Flow from Operations	405.8	219.3	436.1	557.9	809.3	924.9	565.6	377.7
- per share basic	2.75	1.48	2.96	3.70	5.38	6.32	3.95	2.66
- per share diluted	2.58	1.38	2.66	3.32	5.13	6.04	3.75	2.54
Produced Gas Sales (MMcf/d)	1,639	1,432	1,395	1,241	1,221	1,301	1,099	917
Oil and NGL Sales (bbls/d)	129,985	137,125	136,140	135,910	133,118	128,863	120,220	115,922

RESULTS OF OPERATIONS: UPSTREAM

For the three months ended March 31, 2002, Upstream revenues, net of Royalties and production taxes and Transportation and selling expenses, decreased 49% or $726.9 million, to $756.2 million. This compares to an increase in 2001 of 105% or $761.1 million, to $1,483.1 million. The accompanying table shows the details of these changes by product:

Changes in Oil and Natural Gas Revenues

($ million)	2002 Compared to 2001					2001 Compared to 2000				
Factor:	Price	Price Hedge	Volume	Royalties & Other	Total	Price	Price Hedge	Volume	Royalties & Other	Total
North America Natural Gas and NGLs	(922.0)	10.6	359.8	134.7	(416.9)	686.3	10.9	73.3	(191.0)	579.5
Oil										
Conventional	15.3	3.4	13.9	1.0	33.6	(53.5)	-	21.4	3.3	(28.8)
Syncrude	(25.9)	2.3	(3.0)	12.1	(14.5)	6.2	-	28.1	(0.2)	34.1
Purchased Gas Sales	(60.4)	29.5	(272.8)	-	(303.7)	296.6	(108.4)	7.4	-	195.6
International	(9.4)	0.2	(28.8)	12.6	(25.4)	(62.4)	-	28.2	14.9	(19.3)
Total	(1,002.4)	46.0	69.1	160.4	(726.9)	873.2	(97.5)	158.4	(173.0)	761.1

In 2002, the $29.5 million Price Hedge represents payments made by financial intermediaries for Purchased Gas Sales under floating to fixed price swap agreements implemented as a part of the Company's risk management strategy when, at the time of settlement, the market price exceeded the fixed price contract amount. Contemporaneously, similar quantities of gas were forward purchased under fixed price agreements, which, upon settlement, were below market prices in the amount of $1.3 million. For 2002, this strategy resulted in a net benefit of $15.3 million, net of transportation and selling expenses of $15.5 million.

In 2001, the Company made $(108.4) million in Price Hedge payments under floating to fixed price swap agreements. Related fixed price gas purchase agreements were at below market prices in the amount of $161.6 million and resulted in a net benefit of $11.6 million, net of transportation and selling expenses of $41.6 million.

Product Netbacks
The following table summarizes the average net revenue received after deducting transportation, royalties, production taxes and operating costs ("Netback"), by product, for the last eight quarters:

Year	2002	2001				2000		
Quarter	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Canada produced gas ($/Mcf)	2.00	1.84	2.02	4.07	6.79	6.27	3.77	2.84
U.S. produced gas ($/Mcf)	2.15	2.23	2.58	4.54	6.20	5.45	4.43	4.60
North America conventional oil ($/bbl)	15.79	16.60	17.27	12.69	10.99	15.23	25.91	23.26
North America NGLs ($/bbl)	20.03	17.12	25.35	28.28	30.04	34.44	28.39	23.55
Syncrude ($/bbl)	17.49	26.02	15.23	18.47	18.93	20.82	21.11	18.91
Ecuador oil ($/bbl)	9.24	13.07	13.63	13.77	12.13	14.05	18.51	15.70

- Includes hedge impact where applicable

North America Results of Operations

The first quarter North America average produced gas price realized, net of transportation and selling expense, was $3.23/Mcf, down 65% from $9.33/Mcf in 2001. A slowing North American economy and warmer than average winter temperatures resulted in lower demand from virtually all sectors and led to above average storage inventories contributing to the decline in natural gas prices. Natural gas liquids prices decreased 36% to $27.49/bbl from $42.96/bbl in 2001.

North America natural gas production increased to 1,478 MMcf/d, up 21% from the 2001 total of 1,222 MMcf/d in the first quarter. An additional 161 MMcf/d was withdrawn from inventory, bringing total produced gas sales to 1,639 MMcf/d in 2002 compared to 1,221 MMcf/d in 2001, up 34%.

Benchmark West Texas Intermediate oil prices ("WTI") averaged US$21.64/bbl in 2002 for the first three months, compared to the 2001 average of US$28.73/bbl. Light-heavy oil price differentials decreased, returning to more traditional levels, averaging $7.25/bbl compared to $17.31/bbl in 2001. During the first quarter of 2002 WTI strengthened from US$19.73/bbl in January to US$24.44/bbl in March in response to improving supply demand fundamentals resulting from OPEC production restraint and an improved economic outlook in North America. Similarly light heavy differentials narrowed over the first quarter from $9.05/bbl in January to $5.73/bbl in March. This combination has resulted in significantly improved heavy oil prices.

Total North America liquids sales increased 12% to 91,211 bbls/d in the first three months of 2002 compared to 81,536 bbls/d in 2001, primarily as a result of increased conventional crude production in Canada from the Company's SAGD project at Foster Creek.

During the first quarter of 2002, net capital of $661.6 million was invested in North America upstream activities, of which $532.4 million was directed to Canadian operations and $129.2 million to the U.S. operations.

Western Canada

Natural gas prices in Canada averaged $3.20/Mcf, net of transportation and selling expense, in the first three months, down 66% from $9.37/Mcf in 2001 (2000 - $3.00/Mcf). Natural gas production increased 14% to 1,185 MMcf/d from 1,044 Mmcf/d in 2001 due to production from the Ladyfern area and increases in the Greater Sierra area in northeast British Columbia (2000 - 930 MMcf/d). Sales of produced natural gas, which includes the impact of gas injections and withdrawals from gas storage, increased to 1,346 MMcf/d, up 29% from 1,043 MMcf/d in the same period of 2001 (2000 - 965 MMcf/d).

Prices for Canadian conventional crude oil averaged $22.81/bbl, net of transportation and selling expense, and including the impact of price hedges, a 22% increase from the $18.75/bbl averaged in the first three months of 2001 (2000 - $32.41/bbl). This increase was principally as a result of the decrease in light-heavy oil price differentials and the benefit from crude oil hedges which offset a decrease in the WTI average price in the quarter. Prices for Syncrude oil, net of transportation and selling expense and including the impact of price hedges, averaged $34.86/bbl compared to $43.17/bbl in 2001, a 19% decrease compared to the 25% decrease in the WTI benchmark price (2000 - $40.97/bbl). Natural gas liquids prices in Canada decreased to $24.05/bbl from $43.11/bbl in 2001 (2000 - $34.11/bbl).

In the first three months of 2002, the Company produced an average of 51,104 bbls/d of conventional oil in Canada, compared to 42,856 bbls/d produced in 2001, an increase of 19% (2000 - 35,372 bbls/d) primarily as a result of increases from the Foster Creek SAGD project. AEC Syncrude sales averaged 31,548 bbls/d, a decrease of 2% from the 32,319 bbls/d sold in 2001 (2000 - 24,497 bbls/d). Natural gas liquids volumes in Canada increased to 5,406 bbls/d year to date, from 4,805 bbls/d in 2001 (2000 - 4,808 bbls/d).

Operating costs in Canada increased to $143.6 million for the first three months of 2002, compared to $135.2 million in 2001 (2000 - $99.7 million). Higher production volumes resulted in the increase, partially offset by lower natural gas fuel costs at Syncrude.

Year to date sales of purchased gas decreased to 242 MMcf/d in 2002 from 690 MMcf/d in 2001, (2000 – 878 MMcf/d). Revenue from the sale of purchased gas, net of transportation and selling expense, amounted to $116.1 million, down from $419.8 million in 2001 as a result of lower volumes sold and lower average unit sales prices (2000 - $224.3 million). At March 31, 2002, the Company had contracts in place to purchase 84.8 [illegible] of natural gas over an eighteen month period. Contracts were also in place to deliver 69.2 Bcf during the same time frame.

Capital investment focused on exploration and development activities in the Greater Sierra and Ladyfern areas in northeast British Columbia, and further development at Suffield, Caribou and Pelican Lake.

U.S. Rockies

Year to date, U.S. natural gas prices, net of transportation and selling expense, averaged $3.35/Mcf compared to $9.04/Mcf in 2001 which included $0.73/Mcf related to a mark to market adjustment on acquired fixed priced contracts. Natural gas sales increased to 293 MMcf/d from 178 MMcf/d in 2001, reflecting successful ongoing drilling programs, capacity expansion and the addition of production from Mamm Creek. Natural gas liquids volumes increased to 3,153 bbls/d at an average price of $33.38/bbl, up from 1,556 bbls/d at $42.51/bbl in 2001.

Operating costs in the U.S. Rockies increased to $7.8 million for the first three months of 2002, compared to $5.7 million in 2001. Higher production volumes and the addition of Mamm Creek contributed to the increase.

Capital investment in the U.S. Rockies amounted to $129.2 million, year to date, relating to continuing exploration and development of the Jonah and Mamm Creek fields and the acquisition and evaluation of exploratory lands.

Ecuador Results of Operations

Production from Ecuador averaged 50,351 bbls/d in the first quarter of 2002, down 7%, compared to 53,894 bbls/d in 2001, (2000 - 41,703 bbls/d). Sales of crude from Ecuador declined to 38,774 bbls/d from 51,512 bbls/d in 2001 primarily as a result of the timing of tanker shipments leaving port.

Ecuador sales volumes remain constrained by available pipeline transportation which is allocated among shippers based upon the shippers' productive capacity and the quality of crude oil. The completion of the OCP pipeline will remove current transportation constraints.

The Ecuador oil price, net of transportation costs, declined in the first quarter of 2002 to an average of $22.07/bbl, including the impact of allocated price hedges, compared to $24.71/bbl in 2001 as a result of a lower WTI price partially offset by narrower light to heavy differentials and allocated price hedges (2000 - $37.97/bbl). Operating costs in Ecuador increased from $4.53/bbl in the first quarter of 2001 to $5.78/bbl due to lower sales volumes and higher personnel costs.

Capital investments in Ecuador amounted to $132.6 million in the first three months compared to $81.0 million in 2001 and related to continuing exploration and development operations on the Tarapoa Block and Block 15 in preparation for substantially increasing production when the OCP pipeline is completed in 2003.

New Ventures Exploration

Investments in New Ventures Exploration amounted to $22.8 million in the first three months of 2002 compared to $47.3 million in 2001. The Company has ongoing exploration in the Gulf of Mexico, Mackenzie Delta, Alaska, the northwest shelf of Australia and offshore Azerbaijan. During the first quarter the Company participated in exploration wells in Australia and the Gulf of Mexico, neither of which yielded commercial quantities of crude oil and both of which were abandoned. The Company is assessing further drilling in each of these areas.

During the first quarter of 2002, the Company has also entered into exploration commitments in Bahrain, Qatar, and Chad, totaling $140 million over three years.

RESULTS OF OPERATIONS: MIDSTREAM

Midstream revenues decreased 28% to $391.1 million year to date 2002, compared to $542.5 million in 2001 (2000 - $253.3 million), primarily due to the impact of lower natural gas prices on sales related to the Gas storage facility optimization program. Operating Cash Flow decreased 52% from $104.1 million year to date 2001 to $49.9 million in 2002, as a result of lower optimization margins realized and to pipeline dispositions in late 2001.

Midstream Capital

Capital investment in Midstream amounted to $10.7 million in the first three months of 2002, primarily related to ongoing improvements to pipelines facilities.

Construction of the 450,000 bbls/d OCP pipeline in Ecuador continues with completion targeted for the second quarter of 2003. To date, $26.5 million has been invested related to the Company's 31.4% equity interest.

LIQUIDITY AND CAPITAL RESOURCES

Consolidated Cash Flow from Operations totaled $405.8 million in the first quarter of 2002, (2001 - $809.3 million), of which $386.3 million, or 95% of the total, originated in the Upstream division (2001 - $746.9 million) and $19.5 million, was provided by the Midstream division (2001 - $62.4 million). Produced natural gas and natural gas liquids sales provided $256.8 million or 63% of the consolidated total (2001 - $607.8 million), and crude oil added $117.0 million or 29% (2001 - $137.2 million), including allocated corporate costs.

Consolidated cash capital investment totaled $714.5 million in 2002, year to date, in existing core areas (2001 - $963.5 million). An additional $100.8 million cash was invested in corporate and property acquisitions (2001 - $482.8 million), while non-core property dispositions amounted to $35.7 million (2001 - $24.5 million). Total cash net capital investment of $815.3 million exceeded Cash Flow from Operations by $373.8 million. The Company utilized long-term debt to fund the difference.

On a consolidated basis, long-term debt held by the Company, which excludes project financing debt related to the Express System, was $4,290.6 million at March 31, 2002, up $632.6 million from the December 31, 2001 amount of $3,658.0 million. Total long-term debt, including the project financing debt of $580.5 million, is $4,871.1 million (2001 - $4,242.1 million). The Company's unutilized bank credit facilities total $1.6 billion.

Under its Normal Course Issuer Bid, AEC purchased approximately 431,400 shares, for $24.4 million, at an average price of $56.63 in the first quarter of 2002.

Also in the first quarter, the Company declared and paid a special Common Share dividend of forty five ($0.45) cents per Common Share.

RISK MANAGEMENT

The Company's results are influenced by factors such as product prices, interest and foreign exchange rates, royalties, taxes, operations, and credit risk.

The Company has entered into various commodity pricing agreements as a means of managing price volatility. In the first quarter the Company sold forward an additional 400 MMcf/d of natural gas at fixed prices, bringing the total volume subject to fixed price contracts to an average of 1 Bcf/d for the period January to September, 2002. At March 31, 2002 these contracts had an unrealized mark to market loss of $133 million in Canada and US$27 million on the U.S. Rockies contracts.

The Company has entered into various financial instruments to manage price volatility related to its gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. On a combined basis, these instruments had a net unrealized mark to market loss of $23.3 million partially offset by a net unrealized mark to market gain of $21.4 million on physical inventory in storage at March 31, 2002.

Foreign exchange contracts in the amount of US$171.2 million have been entered into to limit U.S. to Canadian exchange rate fluctuations on the Company's natural gas purchase and sale agreements. At March 31, 2002 these contracts had an unrealized mark to market loss of $25.0 million.

An active program of monitoring and reporting day-to-day operations is designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for timely response to an event.

OUTLOOK

The Outlook that follows excludes the impact of the merger transaction completed April 5, 2002, between AEC and PanCanadian.

The Company's sales forecast for 2002 remains at between 1.525 and 1.575 Bcf/d for produced natural gas and between 142,000 and 153,000 bbls/d of crude oil. While commodity price volatility is expected to continue throughout 2002, there are positive signs, as a result of an improving North American economy and the anticipated continuing effectiveness of crude oil supply management by the OPEC producers. The Company's program of natural gas and crude oil price hedges are expected to reduce the revenue impact of any downward trend in prices.

The Company continues to expect capital investment in core programs to be approximately $2.1 billion before dispositions.

AEC and PanCanadian announced on April 5, 2002, all required approvals for the merger of the two companies had been received. The combined organization now operates under the name EnCana Corporation.

April 22, 2002

Consolidated Financial Statements
For the three months ended March 31, 2002

Alberta Energy Company Ltd.

Consolidated Statement of Earnings *Unaudited*

($ millions, except per share amounts)

	Three Months Ended		
	2002	2001	2000
Revenues, net of royalties and production taxes	**$ 1,226.3**	$ 2,088.8	$ 1,019.0
Expenses			
Transportation and selling	**79.0**	63.2	43.7
Operating costs	**216.5**	232.8	154.4
Cost of product purchased	**405.9**	782.1	407.5
General and administrative	**24.2**	16.1	10.3
Interest, net *(Note 4)*	**71.8**	61.3	35.5
Foreign exchange	**0.2**	85.8	4.9
Depreciation, depletion and amortization	**314.7**	264.3	189.5
Earnings Before the Undernoted	**114.0**	583.2	173.2
Minority interest, AEC Pipelines, L.P.	**-**	-	4.7
Income taxes *(Note 5)*	**42.0**	250.6	49.7
Net Earnings	**72.0**	332.6	118.8
Preferred securities charges, net of tax	**16.0**	10.3	5.2
Net Earnings Attributable to Common Shareholders	**$ 56.0**	$ 322.3	$ 113.6
Earnings per Common Share			
Basic	**$ 0.38**	$ 2.15	$ 0.81
Diluted	**$ 0.37**	$ 2.03	$ 0.79

Consolidated Statement of Retained Earnings *Unaudited*

($ millions)

	2002	2001	2000
Balance, Beginning of Year, as Previously Reported	**$ 1,788.1**	$ 1,264.3	$ 744.7
Retroactive Adjustment for Change in Accounting Policy *(Note 2)*	**-**	(24.3)	4.3
Balance, Beginning of Year, as Restated	**1,788.1**	1,240.0	749.0
Adjustment for Change in Accounting Policy *(Note 2)*	**-**	-	(341.3)
Charges for Normal Course Issuer Bid	**(15.5)**	-	(3.7)
Net Earnings	**72.0**	332.6	118.8
	1,844.6	1,572.6	522.8
Common Share Dividends	**(66.5)**	-	-
Preferred Securities Charges, Net of Tax	**(16.0)**	(10.3)	(5.2)
Balance, End of Period	**$ 1,762.1**	$ 1,562.3	$ 517.6

Consolidated Balance Sheet *Unaudited*

($ millions)

	As at March 31, 2002			As at
	Upstream	*Midstream*	**Total**	*December 31, 2001*
Assets				
Current Assets				
Cash and cash equivalents	$ 21.4	$ 64.5	**$ 85.9**	$ 104.4
Accounts receivable and accrued revenue, net	638.4	413.2	**1,051.6**	983.5
Inventories	159.4	208.5	**367.9**	320.8
	819.2	686.2	**1,505.4**	1,408.7
Capital Assets	11,100.1	1,289.0	**12,389.1**	11,866.8
Investments and Other Assets	131.3	674.4	**805.7**	822.0
	$ 12,050.6	$ 2,649.6	**$ 14,700.2**	$ 14,097.5
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	$ 877.6	$ 348.0	**$ 1,225.6**	$ 1,042.8
Income taxes payable	24.5	7.7	**32.2**	241.6
Current portion of long-term debt	-	24.4	**24.4**	49.4
	902.1	380.1	**1,282.2**	1,333.8
Long-Term Debt *(Note 6)*	3,583.7	706.9	**4,290.6**	3,658.0
Project Financing Debt *(Note 7)*	-	580.5	**580.5**	584.1
Other Liabilities	157.0	35.9	**192.9**	204.5
Future Income Taxes	2,102.2	304.1	**2,406.3**	2,360.5
	6,745.0	2,007.5	**8,752.5**	8,140.9
Shareholders' Equity				
Preferred securities			**854.4**	858.8
Share capital *(Note 8)*			**3,073.8**	3,052.3
Retained earnings			**1,762.1**	1,788.1
Foreign currency translation adjustment			**257.4**	257.4
	5,305.6	642.1	**5,947.7**	5,956.6
	$ 12,050.6	$ 2,649.6	**$ 14,700.2**	$ 14,097.5

Consolidated Statement of Cash Flows *Unaudited*

($ millions, except per share amounts)

	Three Months Ended		
	2002	2001	2000
Operating Activities			
Net earnings	**$ 72.0**	$ 332.6	$ 118.8
Depreciation, depletion and amortization	**314.7**	264.3	189.5
Future income taxes	**15.8**	134.5	46.8
Minority interest, AEC Pipelines, L.P.	**-**	-	4.7
Other	**3.3**	77.9	7.4
Cash Flow from operations	**405.8**	809.3	367.2
Net change in non-cash working capital	**(244.0)**	317.4	(24.5)
	161.8	1,126.7	342.7
Investing Activities			
Corporate acquisitions *(Note 3)*	**-**	(435.0)	-
Capital investment	**(815.3)**	(984.8)	(367.5)
Equity investments	**-**	(26.5)	-
Proceeds on disposal of assets	**35.7**	24.5	6.0
Investments and other	**(13.4)**	8.3	(0.6)
Net change in non-cash working capital	**105.8**	240.3	39.2
	(687.2)	(1,173.2)	(322.9)
(Decrease) increase in Cash and Cash Equivalents Before Financing Activities	**(525.4)**	(46.5)	19.8
Financing Activities			
Net issue of long-term debt	**603.4**	29.6	35.5
Issue of common shares	**30.4**	20.8	9.1
Purchase of common shares *(Note 8)*	**(24.4)**	-	(7.0)
Common share dividends	**(66.5)**	-	-
Payments to preferred securities holders	**(10.7)**	(10.3)	(5.2)
AEC Pipelines, L.P. distributions	**-**	-	(6.1)
Net change in non-cash working capital	**(12.3)**	(8.3)	(4.2)
Other	**(13.0)**	32.7	(12.3)
	506.9	64.5	9.8
(Decrease) increase in Cash and Cash Equivalents	**(18.5)**	18.0	29.6
Cash and Cash Equivalents, Beginning of Period	**104.4**	44.6	68.6
Cash and Cash Equivalents, End of Period	**$ 85.9**	$ 62.6	$ 98.2
Cash Flow from Operations per Common Share			
Basic	**$ 2.75**	$ 5.38	$ 2.60
Diluted	**$ 2.58**	$ 5.13	$ 2.56

Notes to Consolidated Financial Statements

1. Basis of Presentation

The Company organizes its operations into two business groups. Upstream includes the Company's North America and International exploration for, and production of, natural gas and crude oil. Midstream includes both the Pipelines and Processing operations and the Gas Storage operations. These interim consolidated financial statements have been prepared on the same basis as the audited consolidated financial statements as at and for the year ended December 31, 2001.

2. Change in Accounting Policy

Effective December 31, 2001, the Company adopted the new Canadian accounting standard for foreign currency translation and, as required by the standard, all prior periods have been restated. The net earnings impact of this change is included in foreign exchange and income taxes on the Consolidated Statement of Earnings.

Effective January 1, 2000, the Company adopted, retroactively without restating prior periods, the liability method of accounting for income taxes as recommended by the Canadian Institute of Chartered Accountants ("CICA"). The Company adopted the recommendations by recording additional capital assets of $273.3 million; a decrease in retained earnings of $341.3 million and an increase in the future income tax liability of $614.6 million.

3. Corporate Acquisitions

On February 2, 2001, the Company acquired all of the issued and outstanding shares of Ballard Petroleum, LLC (Ballard) for net cash consideration of approximately $328.4 million. Ballard is engaged in the exploration for, and production of, natural gas and operates a natural gas pipeline in the United States.

In February 2001, the Company acquired a 36% equity interest in Oleoducto Trasandino (Trasandino) for net cash consideration of US$64.3 million. The Trasandino system transports crude oil from Argentina to refineries in Chile.

4. Interest, Net

	For the three months ended March 31		
	2002	2001	2000
		($ millions)	
Interest expense - long-term debt	73.5	63.9	38.0
Interest expense - other	4.6	3.0	1.2
Interest income	(6.3)	(2.1)	0.8
	71.8	64.8	40.0
Less: Capitalized interest	-	3.5	4.5
Interest, net	71.8	61.3	35.5

5. Income Taxes

	For the three months ended March 31		
The provision for income taxes is as follows:	2002	2001	2000
Current		($ millions)	
Canada	24.9	104.3	2.4
United States	-	7.0	-
Ecuador	1.3	4.4	0.5
Other	-	0.4	-
	26.2	116.1	2.9
Future	15.8	134.5	46.8
Income taxes	42.0	250.6	49.7

6. Long-Term Debt

	March 31, 2002	December 31, 2001
	($ millions)	
Upstream		
Canadian Dollar debt	1,560.1	1,165.2
US Dollar debt (US$1,269.9)	2,023.6	1,907.9
	3,583.7	3,073.1
Midstream		
Canadian Dollar debt	706.9	584.9
	4,290.6	3,658.0

Notes to Consolidated Financial Statements

7. Project Financing Debt

The Express Pipeline System has outstanding US$132.7 million aggregate principal amount of senior secured notes due 2013 bearing interest at 6.47% and US$246.9 million aggregate principal amount of subordinated secured notes due 2019 bearing interest at 7.39% which are non-recourse to the Company. The notes are secured by the assignment of the accounts receivable of Express Pipeline System and a floating charge over the assets of the Canadian portion of the Express System.

8. Share Capital (millions)

	March 31, 2002		December 31, 2001	
	Number	Amount	Number	Amount
Common shares outstanding, beginning of period	147.9	$ 3,052.3	149.9	$ 3,077.4
Shares repurchased	(0.5)	(8.9)	(3.6)	(73.2)
Employee share option plan	0.9	29.0	1.5	45.9
Shareholder Investment Plan	-	1.4	0.1	2.2
Common shares outstanding, end of period	148.3	$ 3,073.8	147.9	$ 3,052.3

During the period, the Company has purchased approximately 0.5 million of its Common Shares for total consideration of $24.4 million, resulting in a reduction of share capital of $8.9 million and a charge to retained earnings of $15.5 million.

The following table summarizes the information about options to purchase Common Shares:

	March 31, 2002		December 31, 2001	
	Share Options	Weighted Average Exercise Price ($)	Share Options	Weighted Average Exercise Price ($)
Outstanding, beginning of period	9.9	45.60	8.7	35.21
Granted	-	58.20	3.1	66.82
Exercised	(0.9)	32.61	(1.5)	29.88
Forfeited	-	49.48	(0.4)	44.76
Outstanding, end of period	9.0	46.96	9.9	45.60

The Company accounts for its stock-based compensation plans using the intrinsic-value method whereby no costs have been recognized in the financial statement for share options granted to employees and directors. As now required by Canadian Generally Accepted Accounting Principles, the impact on compensation costs of using the fair value method, whereby compensation costs had been recorded in net earnings, must be disclosed. If the fair value method had been used, the Company's net earnings and net earnings per share would approximate the following pro forma amounts:

	2002	2001	2000
Compensation Costs	7.7	6.3	5.9
Net Earnings:			
As reported	72.0	332.6	118.8
Pro forma	64.3	326.3	112.9
Net Earnings per Common Share:			
Basic			
As reported	0.38	2.15	0.81
Pro forma	0.33	2.10	0.76
Diluted			
As reported	0.37	2.03	0.79
Pro forma	0.32	1.99	0.75

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants as follows:

Risk free interest rate	3.53%	3.53%	6.02%
Expected lives (years)	4.00	4.00	4.00
Expected volatility	0.32	0.38	0.41
Dividend per share	$ 0.60	$ 0.60	$ 0.40

Notes to Consolidated Financial Statements

9. Segmented Information ($ millions)

(a) Results of Operations

	Western Canada			U.S. Rockies		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 783.1**	$ 1,566.0	$ 741.1	**$ 104.7**	$ 154.8	$ -
Royalties	**90.5**	225.7	79.6	**18.9**	28.4	-
Production Taxes	**-**	-	-	**7.6**	13.2	-
Net Revenues	**692.6**	1,340.3	661.5	**78.2**	113.2	-
Transportation and Selling	**60.2**	44.1	36.5	**6.8**	4.1	-
Operating Costs	**143.6**	135.2	99.7	**7.8**	5.7	-
Cost of Product Purchased	**99.8**	405.1	222.5	**-**	-	-
Operating Cash Flow	**389.0**	755.9	302.8	**63.6**	103.4	-
DD&A	**195.7**	151.0	122.3	**16.6**	9.0	-
DD&A - Acquisitions	**22.7**	21.9	22.7	**24.5**	20.5	-
Segment Income	**$ 170.6**	$ 583.0	$ 157.8	**$ 22.5**	$ 73.9	$ -
Capital Assets - Canada *(including New Ventures)*	**$ 7,179.7**	$ 6,342.1	$ 4,955.2			
- United States *(including New Ventures)*				**$ 1,913.3**	$ 1,569.5	$ 8.4

	North America Total		
	2002	2001	2000
Gross Revenues	**$ 887.8**	$ 1,720.8	$ 741.1
Royalties	**109.4**	254.1	79.6
Production Taxes	**7.6**	13.2	-
Net Revenues	**770.8**	1,453.5	661.5
Transportation and Selling	**67.0**	48.2	36.5
Operating Costs	**151.4**	140.9	99.7
Cost of Product Purchased	**99.8**	405.1	222.5
Operating Cash Flow	**452.6**	859.3	302.8
DD&A	**212.3**	160.0	122.3
DD&A - Acquisitions	**47.2**	42.4	22.7
Segment Income	**$ 193.1**	$ 656.9	$ 157.8
Capital Assets - Canada *(including New Ventures)*	**$ 7,179.7**	$ 6,342.1	$ 4,955.2
- United States *(including New Ventures)*	**$ 1,913.3**	$ 1,569.5	$ 8.4

	Ecuador - Crude Oil			International New Ventures		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 89.0**	$ 129.5	$ 151.2	**$ -**	$ 0.7	$ 5.2
Royalties	**24.6**	37.3	51.6	**-**	0.1	0.6
Production Taxes	**-**	-	-	**-**	-	-
Net Revenues	**64.4**	92.2	99.6	**-**	0.6	4.6
Transportation and Selling	**12.0**	15.0	7.2	**-**	-	-
Operating Costs	**20.1**	21.0	12.2	**9.9**	9.5	8.9
Cost of Product Purchased	**-**	-	-	**-**	-	-
Operating Cash Flow	**32.3**	56.2	80.2	**(9.9)**	(8.9)	(4.3)
DD&A	**21.9**	25.4	18.6	**0.8**	0.7	1.6
DD&A - Acquisitions	**11.4**	13.5	10.0	**-**	-	-
Segment Income	**$ (1.0)**	$ 17.3	$ 51.6	$ (10.7)	$ (9.6)	$ (5.9)
Capital Assets	**$ 1,829.8**	$ 1,476.5	$ 1,124.4	**$ 177.3**	$ 169.1	$ 148.1

	International Total			Upstream Total		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 89.0**	$ 130.2	$ 156.4	**$ 976.8**	$ 1,851.0	$ 897.5
Royalties	**24.6**	37.4	52.2	**134.0**	291.5	131.8
Production Taxes	**-**	-	-	**7.6**	13.2	-
Net Revenues	**64.4**	92.8	104.2	**835.2**	1,546.3	765.7
Transportation and Selling	**12.0**	15.0	7.2	**79.0**	63.2	43.7
Operating Costs	**30.0**	30.5	21.1	**181.4**	171.4	120.8
Cost of Product Purchased	**-**	-	-	**99.8**	405.1	222.5
Operating Cash Flow	**22.4**	47.3	75.9	**475.0**	906.6	378.7
DD&A	**22.7**	26.1	20.2	**235.0**	186.1	142.5
DD&A - Acquisitions	**11.4**	13.5	10.0	**58.6**	55.9	32.7
Segment Income	**$ (11.7)**	$ 7.7	$ 45.7	**181.4**	664.6	203.5
Less: Corporate Costs						
General and administrative				**20.6**	11.4	8.3
Corporate DD&A				**2.6**	2.7	2.6
Interest, net				**44.9**	32.8	27.8
Foreign exchange				**0.4**	54.9	3.7
Income taxes				**41.5**	239.7	46.9
Net Earnings				**$ 71.4**	$ 323.1	$ 114.2
Capital Assets	**$ 2,007.1**	$ 1,645.6	$ 1,272.5	**$ 11,100.1**	$ 9,557.2	$ 6,236.1

	Pipelines and Processing			Gas Storage		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 279.3**	$ 286.1	$ 162.8	**$ 111.8**	$ 256.4	$ 90.5
Royalties	**-**	-	-	**-**	-	-
Production Taxes	**-**	-	-	**-**	-	-
Net Revenues	**279.3**	286.1	162.8	**111.8**	256.4	90.5
Transportation and Selling	**-**	-	-	**-**	-	-
Operating Costs	**25.2**	51.2	27.9	**9.9**	10.2	5.7
Cost of Product Purchased	**216.8**	184.7	109.1	**89.3**	192.3	75.9
Operating Cash Flow	**37.3**	50.2	25.8	**12.6**	53.9	8.9
DD&A	**12.7**	14.8	9.1	**3.4**	2.7	2.4
DD&A - Acquisitions	**1.9**	1.9	-	**-**	-	-
Segment Income	**$ 22.7**	$ 33.5	$ 16.7	**$ 9.2**	$ 51.2	$ 6.5
Capital Assets - Canada	**$ 335.1**	$ 973.2	$ 443.1	**$ 139.9**	$ 134.3	$ 129.6
- United States	**$ 679.1**	$ 1,039.1	$ 370.3	**$ 134.9**	$ 132.5	$ 63.2

	Midstream Total			Consolidated Total		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 391.1**	$ 542.5	$ 253.3	**$ 1,367.9**	$ 2,393.5	$ 1,150.8
Royalties	**-**	-	-	**134.0**	291.5	131.8
Production Taxes	**-**	-	-	**7.6**	13.2	-
Net Revenues	**391.1**	542.5	253.3	**1,226.3**	2,088.8	1,019.0
Transportation and Selling	**-**	-	-	**79.0**	63.2	43.7
Operating Costs	**35.1**	61.4	33.6	**216.5**	232.8	154.4
Cost of Product Purchased	**306.1**	377.0	185.0	**405.9**	782.1	407.5
Operating Cash Flow	**49.9**	104.1	34.7	**524.9**	1,010.7	413.4
DD&A	**16.1**	17.5	11.5	**251.1**	203.6	154.0
DD&A - Acquisitions	**1.9**	1.9	-	**60.5**	57.8	32.7
Segment Income	**31.9**	84.7	23.2	**213.3**	749.3	226.7
Less: Corporate Costs						
General and administrative	**3.6**	4.7	2.0	**24.2**	16.1	10.3
Corporate DD&A	**0.5**	0.2	0.2	**3.1**	2.9	2.8
Interest, net	**26.9**	28.5	7.7	**71.8**	61.3	35.5
Foreign exchange	**(0.2)**	30.9	1.2	**0.2**	85.8	4.9
Minority Interest	**-**	-	4.7	**-**	-	4.7
Income taxes	**0.5**	10.9	2.8	**42.0**	250.6	49.7
Net Earnings	**$ 0.6**	$ 9.5	$ 4.6	**$ 72.0**	$ 332.6	$ 118.8
Capital Assets - Canada	**$ 475.0**	$ 1,107.5	$ 572.7			
- United States	**$ 814.0**	$ 1,171.6	$ 433.5			

Notes to Consolidated Financial Statements

9. Segmented Information (continued)

(b) Net Capital Investment *

	2002	2001	2000
Upstream			
North America			
Conventional	$ 633.0	$ 745.6	$ 301.0
Syncrude	39.6	15.9	19.5
International	138.8	97.3	28.7
Midstream			
Pipelines and Processing	8.4	50.2	6.5
Gas Storage	2.3	70.5	3.5
Other	5.6	7.3	2.3
Total	$ 827.7	$ 986.8	$ 361.5

** excludes corporate acquisitions and corporate dispositions*

(c) Geographic and Product Information

The following tables provide additional product and geographic information for Upstream North America and Midstream not provided in Note (a) Results of Operations:

Upstream North America

	Natural Gas and NGLs								
	Western Canada			United States			Purchased Gas - Canada		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 431.0**	$ 926.0	$ 297.7	**$ 104.7**	$ 154.8	$ -	**$ 141.4**	$ 435.0	$ 242.4
Royalties	**81.3**	203.3	54.1	**18.9**	28.4	-	**-**	-	-
Production Taxes	**-**	-	-	**7.6**	13.2	-	**-**	-	-
Net Revenues	**349.7**	722.7	243.6	**78.2**	113.2	-	**141.4**	435.0	242.4
Transportation and Selling	**28.5**	22.3	13.6	**6.8**	4.1	-	**25.3**	15.2	18.1
Operating Costs	**70.5**	50.5	38.1	**7.8**	5.7	-	**0.2**	6.9	1.9
Cost of Product Purchased	**-**	-	-	**-**	-	-	**99.8**	405.1	222.5
Operating Cash Flow	**$ 250.7**	$ 649.9	$ 191.9	**$ 63.6**	$ 103.4	$ -	**$ 16.1**	$ 7.8	$ (0.1)

	Crude Oil					
	Western Canada			Syncrude - Canada		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 110.8**	$ 77.0	$ 108.2	**$ 99.9**	$ 128.0	$ 92.8
Royalties	**9.9**	10.9	14.2	**(0.7)**	11.5	11.3
Net Revenues	**100.9**	66.1	94.0	**100.6**	116.5	81.5
Transportation and Selling	**5.9**	4.7	3.8	**0.5**	1.9	1.0
Operating Costs	**22.5**	19.0	14.4	**50.4**	58.8	45.3
Operating Cash Flow	**$ 72.5**	$ 42.4	$ 75.8	**$ 49.7**	$ 55.8	$ 35.2

Notes to Consolidated Financial Statements

9. Segmented Information (continued)

(c) Geographic and Product Information (continued)

Midstream - Pipelines and Processing

	Canada			United States		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 245.4**	$ 238.3	$ 139.8	**$ 33.9**	$ 47.8	$ 23.0
Operating Costs	**10.6**	29.6	18.1	**14.6**	21.6	9.8
Cost of Product Purchased	**204.7**	176.2	99.3	**12.1**	8.5	9.8
Operating Cash Flow	**$ 30.1**	$ 32.5	$ 22.4	**$ 7.2**	$ 17.7	$ 3.4

Midstream - Gas Storage

	Canada			United States		
	2002	2001	2000	**2002**	2001	2000
Gross Revenues	**$ 47.0**	$ 159.3	$ 71.2	**$ 64.8**	$ 97.1	$ 19.3
Operating Costs	**4.0**	7.8	3.6	**5.9**	2.4	2.1
Cost of Product Purchased	**38.2**	122.0	59.7	**51.1**	70.3	16.2
Operating Cash Flow	**$ 4.8**	$ 29.5	$ 7.9	**$ 7.8**	$ 24.4	$ 1.0

(d) Total Assets

	2002	2001	2000
Upstream			
North America			
Conventional	**$ 9,036.7**	$ 8,210.9	$ 4,887.0
Syncrude	**777.2**	650.3	584.0
International	**2,236.7**	1,844.9	1,468.5
Midstream			
Pipelines and Processing	**1,951.2**	2,534.2	1,195.0
Gas Storage	**698.4**	318.7	103.5
Total	**$ 14,700.2**	$ 13,559.0	$ 8,238.0

10. Subsequent Event

On January 27, 2002, AEC and PanCanadian Energy Corporation ("PanCanadian") announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the *Business Corporations Act* (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common share of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders and optionholders of AEC and of the common shareholders of PanCanadian, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation ("EnCana"). On completion of the transaction, former AEC shareholders own approximately 46% and former PanCanadian shareholders own approximately 54% of EnCana.