ENCANA CORPORATION

ENCANA

TSX/NYSE SYMBOL: ECA

INTERIM REPORT FOR THE PERIOD ENDED SEPTEMBER 30, 2003

ENCANA'S THIRD QUARTER CASH FLOW UP 32% TO $1.4 BILLION, EARNINGS NEARLY DOUBLE TO $400 MILLION

Balance sheet remains strong after large capital program and share buyback

CALGARY, ALBERTA – EnCana Corporation's (TSX & NYSE: ECA) continued growth in oil and gas sales combined with strong commodity prices generated cash flow of $1.4 billion, or $2.81 per common share diluted, during the third quarter of 2003, up 32 percent from $1.02 billion during the third quarter of 2002. Earnings were $400 million, or 82 cents per common share diluted, up 96 percent from earnings of $204 million in the third quarter of 2002. Revenues, net of royalties and production taxes, in the third quarter of 2003 were $3.1 billion. Capital investment, excluding acquisitions and dispositions, was $1.85 billion.

GROWTH FROM EXISTING ASSETS ON TRACK IN THIRD QUARTER OF 2003

Third quarter oil, natural gas liquids (NGLs) and natural gas sales, excluding Syncrude, averaged 745,000 barrels of oil equivalent (BOE) per day, up more than 9 percent compared to sales of 682,000 barrels of oil equivalent per day during the third quarter of 2002. Daily natural gas sales increased more than 10 percent to average 2.96 billion cubic feet compared to 2.69 billion cubic feet during the third quarter of 2002. Oil and NGLs sales, excluding Syncrude, increased more than 7 percent, averaging 252,000 barrels per day, compared to 234,000 barrels per day in the third quarter of 2002. EnCana drilled 1,830 net wells in the third quarter of 2003.

INVESTMENT FOCUSED ON GROWTH AND RETURNS

"EnCana's investment strategy is focused on achieving both strong growth and strong returns, a combination aimed at continuously increasing the intrinsic value of every share. Through 2003, we have divested of assets that have not met our stringent financial return thresholds, such as our Syncrude interest, which represented 32,000 barrels per day, or about 4 percent of EnCana's production. We have redeployed a portion of those sale proceeds into buying about 20 million of our shares for cancellation, representing about 4.25 percent of the shares outstanding in October 2002. We believe this to be a value creating strategy for EnCana's shareholders, given the confidence we have in the ability of our asset base to produce low-risk, high-return growth," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

ORGANIC GROWTH FROM UNDERLYING ASSETS ON TRACK AT 10 PERCENT IN 2003

EnCana is on track to achieve about 10 percent organic production growth from continuing operations in 2003. Excluding Syncrude, total pro forma production in 2002 was 687,000 barrels of oil equivalent per day. Strong production increases are underway in the fourth quarter, putting the company on pace to achieve sales this year approaching the midpoint of its guidance, which is between 740,000 and 797,000 barrels of oil equivalent per day.

On an all in basis, including discontinued Syncrude operations, EnCana's pro forma sales for 2002 were 722,500 barrels of oil equivalent per day. Comparing this to total forecast sales in 2003, and forecast reduction in shares outstanding from year-end 2002 to year-end 2003, puts EnCana on track to achieve an all in production per share growth rate in 2003 in excess of 10 percent.

FOURTH QUARTER PRODUCTION RISING IN SEVERAL REGIONS

"In Ecuador, the recent completion of the new export pipeline has nearly doubled production to more than 96,000 barrels of oil per day. In the U.K. central North Sea, we have taken over operatorship of the Scott Telford production platform and increased our ownership in the project by 14 percent, resulting in an increase in our sales to about 17,000 barrels of oil equivalent per day," Morgan said.

"In North America, our U.S. Rockies, British Columbia and southern Alberta resource plays are fuelling profitable gas growth. We drilled more than 1,800 net wells across the continent during the third quarter, most of which are yet to come on stream. An estimated 1,400 completed gas wells are expected to be tied into gathering systems during the fourth quarter, adding about 200 million cubic feet of gas production per day," Morgan said.

The company is on target to achieve its 2003 sales forecast of between 740,000 and 797,000 barrels of oil equivalent per day. To date in October, sales are averaging more than 810,000 barrels of oil equivalent per day, comprised of 3.1 billion cubic feet of gas and 300,000 barrels of oil and NGLs. EnCana expects to exit the year producing between 820,000 and 840,000 barrels of oil equivalent per day from continuing assets – up more than 12 percent from the 2002 exit rate and well within the company's forecast 2004 sales range of between 805,000 and 885,000 barrels of oil equivalent per day.

MAJOR NEW RESOURCE PLAY AT CUTBANK RIDGE

In September, EnCana announced the capture of a major new resource play at Cutbank Ridge covering about 500,000 net acres near the foothills of British Columbia and Alberta and containing an estimated 4 trillion cubic feet of recoverable gas. Similar to the company's resource plays at Greater Sierra in northeast B.C., Jonah in Wyoming, Mamm Creek in Colorado and Palliser and Suffield in southern Alberta, Cutbank Ridge is expected to deliver steady, profitable, long-life production growth for many years to come. The productive Cadomin geological formation underlying Cutbank Ridge lands is an expansive gas-charged reservoir where EnCana believes it can apply its proven assembly-line, resource play management system to generate several hundred million cubic feet of daily gas production in the years ahead. With Cutbank Ridge added to its portfolio, EnCana is now estimating that, beyond its proved and risked probable booked reserves, the company's existing lands contain unbooked resource potential of approximately 11 trillion cubic feet of gas and 650 million barrels of oil. Over the coming years, EnCana expects to convert these resources to reserves.

All references to production, sales and financial information for the first nine months of 2002 in this news release text and tables for EnCana are presented on a pro forma basis as if the merger of PanCanadian Energy Corporation ("PanCanadian" or "PCE") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of 2002. All dollar figures are Canadian unless otherwise stated.

NINE MONTHS CASH FLOW HITS $4.6 BILLION, NET EARNINGS $2.7 BILLION

During the first nine months of 2003, EnCana's net earnings increased 229 percent from the first nine months of 2002 to $2.7 billion, or $5.60 per common share diluted. Net earnings include gains totalling $406 million after tax, or 83 cents per common share diluted, as a result of foreign exchange translation on U.S. dollar denominated debt. While the stronger Canadian dollar results in gains on the U.S. dollar denominated debt, it adversely impacts the average net Canadian dollar price realized by the company on its sales of oil, NGLs and natural gas, which are either directly denominated in U.S. dollars or denominated in Canadian dollars but closely tied to U.S. currency. Cash flow for the first nine months of 2003 was up 69 percent over the same period of 2002 to $4.6 billion, or $9.55 per common share diluted. Revenues, net of royalties and production taxes, in the first nine months were $10.4 billion. Capital investment in the first nine months, excluding acquisitions and dispositions, was $4.9 billion.

NORTH AMERICAN NATURAL GAS INDUSTRY PRICES REMAIN STRONG

Natural gas prices across North America remained strong due to marginally lower supplies in the U.S. and Canada and the need to replenish the low storage levels at the end of last winter. In the third quarter, the average benchmark NYMEX index price was US$4.97 per thousand cubic feet, up 56 percent from the third quarter of 2002. North American storage injections increased during the summer months taking gas storage levels close to long-term averages. In the third quarter, the company's average realized field gate natural gas price, excluding hedging, was C$5.88 per thousand cubic feet; including hedging it was C$5.81 per thousand cubic feet.

WORLD OIL PRICES REMAIN STRONG IN THE WAKE OF CONTINUED SUPPLY UNCERTAINTY

During the third quarter, the average benchmark West Texas Intermediate crude oil price was US$30.21 per barrel, up 7 percent over the same period last year. The Organization of Petroleum Exporting Countries' decision to cut oil supplies by 900,000 barrels per day effective November 1, 2003 and uncertainty regarding Iraqi production continue to support world oil prices at relatively high levels. EnCana's third quarter average realized oil and NGLs price, excluding hedging, was C$28.24 per barrel; including hedging it was C$25.63 per barrel.

RISK MANAGEMENT PROGRAMS HELP MITIGATE VOLATILITY

EnCana's risk management program is designed to partially mitigate the volatility associated with commodity prices, exchange rates and interest rates. From time to time, EnCana will fix prices on future oil and gas sales in order to lock in financial returns and reduce cash flow at risk. EnCana has about 40 percent of projected 2004 gas sales, after royalties, hedged at an average effective NYMEX price of about US$5.23, based upon a 1.32 C$/US exchange rate and a US$0.73 per thousand cubic feet AECO basis for Canadian conversions. About half of EnCana's projected 2004 oil sales, after royalties, are hedged or subject to costless collars between US$20 and US$26 WTI. The detailed risk management positions at September 30, 2003 are presented in Note 10 to the third quarter Consolidated Financial Statements. With strong oil and gas prices and changes to exchange rates in the third quarter, EnCana's financial commodity price and currency risk management measures resulted in revenue being lower by approximately $81 million, comprised of $61 million on oil sales and $20 million on gas sales.

Consolidated EnCana Highlights

FINANCIAL HIGHLIGHTS

(unaudited) *(as at and for the periods ended September 30)* *($ millions, except per share amounts)*	**Q3 2003 Actuals**	Q3 2002 Actuals	**9 Months 2003 Actuals**	9 Months 2002 Pro forma[2]
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	**3,116**	2,741	**10,378**	7,489
Cash Flow				
Per common share – diluted	**1,352**	1,022	**4,642**	2,739
	2.81	2.12	**9.55**	5.66
Net earnings				
Per common share – basic[1]	**400**	204	**2,712**	825
Per common share – diluted	**0.83**	0.43	**5.69**	1.74
	0.82	0.42	**5.60**	1.70
Less:				
Foreign exchange gain (loss) on translation of US$ debt (after-tax)	**14**	(145)	**406**	17
Per common share – basic	**0.03**	(0.30)	**0.85**	0.04
Per common share – diluted	**0.03**	(0.30)	**0.83**	0.04
Less:				
Tax rate change gain	–	–	**486**	42
Per common share – basic	–	–	**1.02**	0.09
Per common share – diluted	–	–	**1.00**	0.09
Net earnings, excluding above gains (losses)	**386**	349	**1,820**	766
Per common share – basic	**0.80**	0.73	**3.82**	1.61
Per common share – diluted	**0.79**	0.72	**3.77**	1.57
Capital investment	**1,849**	1,440	**4,880**	4,084
				at Dec. 31/02
Total assets			**30,212**	31,322
Long-term debt			**7,103**	7,395
Preferred securities			**549**	583
Shareholders' equity			**14,953**	13,794
Debt-to-capitalization ratio (adjusted for working capital & including preferred securities as debt)			**33%**	31%
Common shares (millions)				
Outstanding at September 30	**465.0**	477.4	**465.0**	477.4
Weighted average (diluted)	**480.5**	482.2	**486.3**	483.6

1 **Impact of including share options in earnings calculations**
If EnCana were to record compensation expense for outstanding share options, net earnings per common share – basic would have been $5.58 per common share, 11 cents per common share less, for the first nine months of 2003.

2 **Important Notice: Readers are cautioned that comparisons to 2002 nine months results are based on pro forma calculations and these pro forma results may not reflect all adjustments and reconciliations that may be required under Canadian generally accepted accounting principles. These pro forma results may not be indicative of the results that actually would have occurred or of the results that may be obtained in the future. Also, certain information provided for prior years has been reclassified to conform to the presentation adopted in 2003.**

Consolidated EnCana Highlights

OPERATING HIGHLIGHTS

(for the period ended September 30)	**Q3 2003 Actuals**	Q3 2002 Actuals	% Change	**9 Months 2003 Actuals**	9 Months 2002 Pro forma[2]	% Change
SALES						
Natural gas *(MMcf/d)*						
North America	**2,954**	2,679	+ 10	**2,955**	2,654	+ 11
U.K.	**7**	9	– 22	**11**	10	+ 10
Total natural gas *(MMcf/d)*	**2,961**	2,688	+ 10	**2,966**	2,664	+ 11
Oil and NGLs *(bbls/d)*						
North America	**192,385**	169,069	+ 14	**184,523**	166,572	+ 11
Ecuador	**53,543**	55,579	– 4	**48,667**	51,467	– 5
U.K.	**5,813**	9,538	– 39	**8,463**	11,453	– 26
Total oil and NGLs* *(bbls/d)*	**251,741**	234,186	+ 7	**241,653**	229,492	+ 5
Total sales *(BOE/d)**	**745,241**	682,186	+ 9	**735,986**	673,492	+ 9
Prices						
Natural Gas *($/Mcf)*						
Including hedging						
Canada	**5.76**	3.53	+ 63	**6.37**	3.68	+ 73
U.S.	**5.94**	3.73	+ 59	**6.68**	3.61	+ 85
Excluding hedging						
Canada	**5.80**	3.24	+ 79	**6.71**	3.56	+ 88
U.S.	**6.11**	3.16	+ 93	**6.57**	3.33	+ 97
Total North American gas *($/Mcf)*						
Including hedging	**5.81**	3.56	+ 63	**6.45**	3.67	+ 76
Excluding hedging	**5.88**	3.21	+ 83	**6.68**	3.52	+ 90
Oil and NGLs *($/bbl)*						
Including hedging						
North American oil						
Light/medium	**28.51**	35.12	– 19	**31.08**	31.56	– 2
Heavy	**20.01**	28.55	– 30	**21.94**	25.62	– 14
International oil						
Ecuador	**28.40**	33.59	– 15	**33.27**	29.97	+ 11
U.K.	**35.79**	39.30	– 9	**38.37**	35.72	+ 7
Natural gas liquids	**33.10**	31.18	+ 6	**36.01**	27.93	+ 29
Excluding hedging						
North American oil						
Light/medium	**32.59**	36.01	– 9	**36.56**	32.65	+ 12
Heavy	**23.96**	29.44	– 19	**27.05**	26.14	+ 3
International oil						
Ecuador	**28.40**	33.59	– 15	**33.27**	29.97	+ 11
U.K.	**35.79**	39.30	– 9	**38.37**	35.83	+ 7
Natural gas liquids	**33.10**	31.18	+ 6	**36.01**	27.93	+ 29
Total oil and NGLs *($/bbl)*						
Including hedging	**25.63**	32.27	– 21	**28.75**	29.09	– 1
Excluding hedging	**28.24**	32.83	– 14	**32.12**	29.59	+ 9

* Excludes EnCana's share of Syncrude volumes, which averaged 3,401 barrels per day in the third quarter of 2003, compared to 36,039 barrels per day in the third quarter of 2002. For the first nine months of 2003, Syncrude volumes averaged 10,291 barrels per day, compared to 30,644 barrels per day in the same period in 2002.

CORPORATE DEVELOPMENTS

Normal Course Issuer Bid purchases

In the past 12 months, EnCana invested approximately $1 billion to purchase 20,224,400 common shares, representing approximately 4.25 percent of the company's outstanding shares on October 21, 2002, at an average price of $50.35 per common share. These purchases more than offset the approximately 4.8 million shares issued to date this year as a result of the exercise of share purchase options. On October 14, 2003 the company's total common shares outstanding was 464,246,813.

Normal Course Issuer Bid renewed

EnCana has received approval for the renewal of the company's Normal Course Issuer Bid from the Toronto Stock Exchange. Under the renewed bid, which commenced on October 22, 2003, EnCana may, over a 12-month period, purchase for cancellation up to 23,212,341 of its common shares, representing 5 percent of the 464,246,813 common shares outstanding as at October 14, 2003. The price paid will be the market price at the time of acquisition.

Dividend

The board of directors of EnCana declared a quarterly dividend of 10 cents per share payable on December 31, 2003 to common shareholders of record as of December 12, 2003.

Cash tax outlook

EnCana's estimate of normalized annual cash tax expense, with its current projected production, commodity prices, capital investment and exchange rate profile, is about $500 million per year. Largely as a result of the business reorganization arising from the merger, this pattern has shifted for 2003 and 2004. In 2003, cash taxes are expected to be about $400 million lower than the normalized level, while 2004 cash taxes are expected to be higher by a similar amount. For 2005, the company is expected to return to more normalized annual levels of cash tax.

U.S. protocol reporting of financial and operating results

Starting with year-end 2003, EnCana plans to report its financial and operating results following U.S. protocols in order to facilitate a more direct comparison to other North American upstream exploration and development companies. Financial results will be in U.S. dollars and EnCana's operating results, namely production and reserves, will be reported on an after-royalties basis. EnCana will also provide convenience statements prepared in Canadian dollars, along with operating results following Canadian protocols – production and reserves reported on a before-royalties basis.

Forecast of 10 percent internal sales growth in 2003 and 2004 confirmed

Total 2003 daily sales volumes from continuing operations are forecast to increase approximately 10 percent from pro forma 2002 levels, averaging between 740,000 and 797,000 barrels of oil equivalent, which is comprised of between 3 billion and 3.1 billion cubic feet of gas per day and 240,000 and 280,000 barrels of oil and NGLs per day. In 2004, daily sales are expected to average between 805,000 and 885,000 barrels of oil equivalent, comprised of natural gas sales between 3.25 billion and 3.45 billion cubic feet per day and 265,000 and 310,000 barrels of oil and NGLs per day, representing a 10 percent increase from the midpoint of forecast 2003 sales levels.

FINANCIAL STRENGTH

EnCana has a strong balance sheet. At September 30, 2003, the company's debt-to-capitalization ratio was 33:67 (preferred securities included as debt). EnCana's Debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.1 times. Third quarter capital investment was $1,849 million. Divestiture proceeds, net of acquisitions, were about $300 million.

On October 2, 2003, EnCana completed a public offering in the United States of US$500 million of 4.75% Notes due October 15, 2013. The net proceeds of the offering have been used to repay existing floating-rate bank and commercial paper indebtedness. As at September 30, 2003, on a pro forma basis, taking into account this offering, approximately 53 percent of EnCana's outstanding debt was in U.S. dollars and 72 percent of total debt was long-term fixed rate. EnCana has received strong investment grade credit ratings from the major bond rating services: A(low) by Dominion Bond Rating Service Limited; Baa1 by Moody's Investors Service and A- by Standard and Poor's Ratings Services. The company also has a $4 billion credit facility with a syndicate of major banks and lending institutions, of which more than $1.78 billion remains unutilized at September 30, 2003.

Year-to-date core capital investment, before acquisitions and dispositions, was about $4.6 billion, while acquisitions were about $600 million and divestiture proceeds were about $2.4 billion, resulting in net capital investment of about $2.8 billion in the first nine months.

Capital investment update

EnCana 2003 forecast capital program *($ millions)*

Upstream	
Offset production declines (estimated)	2,600
2003 and part of 2004 growth (estimated)	1,700
Exploration and long term development	600
Cutbank Ridge land purchase	400
Upstream total	**5,300**
Midstream	
Original forecast	500
OCP Pipeline additional requirements	100
Midstream total	**600**
Core Capital total (forecast)	**5,900**
Other	
Leased equipment purchases*	300
Minor corporate acquisitions	300
Other total	**600**
Divestitures	
Express and Cold Lake pipelines**	(1,600)
Syncrude	(1,500)
Divestitures total	**(3,100)**
Net Capital Investment (forecast)	**3,400**

* Represents the conversion of previous operating leases to EnCana ownership.

** $1.6 billion less $600 million of net assumption, by the purchaser, of debt resulted in net cash proceeds of $1.0 billion.

EnCana's 2003 upstream core capital investment is expected to be about $5.3 billion, an increase of about $400 million from the upper end of previous guidance. It is directed as follows: about $2.6 billion to offset annual production declines and about $1.7 billion for 2003 and a portion of 2004 production growth. Another $1 billion is directed to exploration, including Cutbank Ridge and multi-year development projects such as the Buzzard field. Total Midstream & Marketing capital is about $600 million. Minor corporate acquisitions total about $300 million and divestitures will generate total proceeds of $3.1 billion, resulting in a net 2003 capital investment forecast of $3.4 billion.

Preliminary reserve replacement cost estimated at less than $10 per barrel of oil equivalent

Based on the total upstream capital investment of about $5.9 billion, which includes core capital investment, minor acquisitions and most of the cost of purchases of previously leased equipment, the company's preliminary 2003 proved reserve replacement cost estimate will be similar to that reported in 2002. In 2002, EnCana's proved reserve replacement cost was $9.60 per barrel of oil equivalent.

Merger synergies update

EnCana estimates that it has implemented sustainable capital investment synergies of about $250 million and one-time, non-recurring capital synergies of about $380 million. EnCana has a tremendous inventory of investment opportunities, which in the post-merger period have led to more selective capital decisions yielding stronger economic metrics than either predecessor company could have accomplished. The company is also on track to realize annual recurring operating and administrative synergies of about $250 million per year.

Operating costs averaged $4.14 per barrel of oil equivalent for the third quarter of 2003 and $4.10 per barrel of oil equivalent for the first nine months of 2003, which is at the high end of the company's $3.80 to $4.10 per barrel of oil equivalent target. With production forecast to increase in the fourth quarter, EnCana expects its per unit operating costs to decline marginally.

OPERATIONAL HIGHLIGHTS

North America

Third quarter natural gas and liquids sales up 11 percent year over year

North American gas, oil and NGLs sales, excluding Syncrude, continued to grow in the third quarter, averaging 685,000 barrels of oil equivalent per day – an 11 percent increase over the average of 616,000 barrels of oil equivalent per day in the third quarter of 2002. Natural gas sales were up 10 percent, averaging 2.95 billion cubic feet per day. Liquids sales, excluding Syncrude, were up 14 percent year over year, averaging 192,000 barrels per day. Production from the U.S. Rockies continues to achieve very strong year-over-year growth. An earlier than normal winter break up in northern Canadian locations and a wet spring across much of the Canadian plains resulted in a three-month delay in much of the company's drilling program. Favourable weather has enabled much of the delayed program to be completed during the summer. An estimated 200 million cubic feet of daily production is expected to be connected to gathering systems during the fourth quarter. As a result of these delays, EnCana expects to achieve average 2003 gas sales volumes at the low end of its guidance range, but to exit 2003 already within the range of its 2004 gas sales guidance.

During the third quarter, the company did not inject gas production into storage since prices remained relatively high, with the AECO price index averaging $6.29 per thousand cubic feet of gas.

EnCana drilled 1,817 net wells in North America during the third quarter, and currently has about 25 rigs running in the U.S. Rockies and about 80 rigs across Western Canada.

USA region gas production surpasses 800 million cubic feet per day

Third quarter gas sales from the USA region rose 38 percent in the past year to average 757 million cubic feet per day, compared to an average of 550 million cubic feet per day for the same period in 2002. October production to date, which is largely from the Jonah field in Wyoming and the Mamm Creek field in Colorado, is more than 800 million cubic feet per day. In order to help mitigate pricing risk due to gas transportation constraints out of the U.S. Rockies, EnCana has fixed the price differential between NYMEX and the Rockies on 764 million cubic feet per day of gas sales for the remainder of 2003 at an average basis of US$0.52 per thousand cubic feet, and an average of 520 million cubic feet per day of forecast gas sales for 2004 through 2007 at an average basis of US$0.49 per thousand cubic feet.

"The Mamm Creek field, which we purchased in early 2001, is a classic resource play asset. Its production and reserves continue to grow and this low decline gas field has a large unbooked resource potential. In each of the past two years we have doubled daily gas production, from 35 million in 2001, to 70 million in 2002 and we are targeting a 2003 average of approximately 150 million cubic feet. At the same time, our costs to drill and complete a well have decreased by about 25 percent. With about 20 rigs currently drilling in the area, we are expecting continued strong performance from this high-growth asset," said Roger Biemans, President of EnCana's USA region.

In the Gulf of Mexico, EnCana holds a 25 percent interest in the recently-announced Sturgis deepwater discovery in Atwater Valley block 183, about 240 kilometres southeast of New Orleans, Louisiana. Located in about 3,700 feet of water, the Sturgis No.1 well encountered more than 100 feet of net pay of hydrocarbon-bearing sands. A subsequent side-track wellbore was drilled to a depth of 27,739 feet.

"Along with our earlier success this year in our appraisal drilling program at Tahiti, we are very encouraged by this latest find. We look forward to additional appraisal drilling at Sturgis by the operator – ChevronTexaco," said Gerry Macey, EnCana's President of International New Ventures Exploration.

Second major resource play added in northeast British Columbia at Cutbank Ridge

Over the past 18 months, EnCana has assembled more than 500,000 net acres (about 780 sections) of prospective lands that the company believes constitute a major new resource play at Cutbank Ridge near the foothills of the Canadian Rocky Mountains. Straddling the B.C.-Alberta border, EnCana's Cutbank Ridge lands are estimated to contain more than 4 trillion cubic feet of recoverable gas.

"We believe Cutbank Ridge will perform like our other resource plays at Greater Sierra in northeast B.C., the Jonah field in Wyoming, Mamm Creek in Colorado and Palliser and Suffield in southern Alberta. It's exactly the type of large-scale resource play we strive to capture and develop, one with the potential to generate several hundred million cubic feet per day of long-life, low decline gas production for many years to come," said Randy Eresman, EnCana's Chief Operating Officer. "These are the kinds of assets where we believe we can grow both production and reserves while our highly-focused business unit teams drive down costs by applying our proven resource play management system."

Cutbank Ridge is estimated to contain 6 billion cubic feet of recoverable natural gas per section. The initial cost of drilling and completing each horizontal well, including gathering pipelines and facilities, is estimated at about $4 million. All in, full-life-cycle finding and development costs at Cutbank Ridge are expected to be about $1.50 per thousand cubic feet of gas, which should make the investment highly profitable.

Greater Sierra builds upon summer drilling program

EnCana's Greater Sierra project is nearing the completion of 80 summer wells, more than double the number EnCana had planned earlier this year. With the positive changes in the B.C. government's royalty regime for summer drilling and its commitment to improve road infrastructure, EnCana has stepped up its development at Greater Sierra. Production is currently about 220 million cubic feet per day and once summer wells are tied in, sales are expected to exit the year near 300 million cubic feet per day. As well, construction of EnCana's new Ekwan Pipeline is expected to start in December. This 80 kilometre link to the Alberta gas transmission system has a planned capacity of more than 400 million cubic feet per day. With planned start-up by the second quarter of 2004, the Ekwan Pipeline is expected to facilitate continued sales growth from northeast British Columbia.

Coalbed methane development expands

EnCana is continuing to obtain technical and operational data required for large-scale coalbed methane (CBM) development on its 100-percent-owned shallow gas lands east of Calgary. EnCana's commercial demonstration project is producing about 3 million cubic feet of gas per day from about 35 wells. During the last half of 2003, the company is drilling an additional 100 wells that are expected to take production to about 10 million cubic feet per day by year-end.

Suffield and Pelican Lake surpassing expectations

Heavy oil production growth at Suffield in southeast Alberta has risen 21 percent to over 40,000 barrels per day since the beginning of the year. Performance of EnCana's Pelican Lake waterflood project in northeast Alberta is exceeding expectations as production to date in 2003 has averaged 16,000 barrels per day, up about 20 percent from initial forecasts. Based on the strong response from the 60 horizontal water injector wells turned on since project initiation in early 2002, Pelican Lake production is expected to rise more than 25 percent in 2004 to more than 20,000 barrels per day.

New phase underway for SAGD growth at Foster Creek

EnCana is injecting steam into its first expansion at Foster Creek in northeast Alberta, where oil production averaged more than 22,000 barrels per day during the third quarter. The six well pair expansion is expected to take total EnCana SAGD production, which includes other projects, to approximately 35,000 barrels per day by mid 2004.

East Coast – encouraging exploration results

EnCana has completed the drilling of two exploration wells near its Deep Panuke natural gas field, about 250 kilometres southeast of Halifax. Preliminary results from both wells – Margaree and MarCoh – are encouraging. EnCana holds 100 percent of Margaree and has 24.5 percent of MarCoh, where ExxonMobil owns 51 percent and Shell Canada holds 24.5 percent. In February 2003, EnCana initiated a comprehensive review of its Deep Panuke project in order to strengthen the anticipated economics of field development. The drilling results from Margaree and MarCoh will be incorporated into the company's overall review. EnCana plans to update federal and provincial regulators on the status of its Deep Panuke evaluation in December.

"It is still too early to know precisely how development of this promising field may unfold. However, we are certainly encouraged by this additional drilling, which increases our confidence in the size of the reserve and the development potential at Deep Panuke," Eresman said.

International

Third quarter oil sales from international operations averaged about 59,400 barrels of oil per day, down about 9 percent compared to the third quarter last year. With the OCP Pipeline in operation and EnCana's expanded ownership in the Scott and Telford oil fields, October daily oil production to date from international locations is now more than 110,000 barrels of oil equivalent per day.

Fourth quarter Ecuador production expected to double

Third quarter sales in Ecuador averaged about 53,500 barrels of oil per day, down about 4 percent from an average of about 55,600 barrels per day one year earlier. The lower sales are due largely to the delivery of about 6,800 barrels per day during the quarter for use as line fill on the new OCP Pipeline, which recently completed and passed performance testing. EnCana had hoped OCP would be completed early in the summer, but a significant volcanic eruption and subsequent mud flows, which occurred as pipeline construction was nearing completion, delayed the initial start date. However, with the opening of the pipeline in early September, EnCana has now taken its Ecuador production to more than 96,000 barrels per day, well on the way to the company's 2004 target of more than 100,000 barrels per day of production. In September, EnCana sold three tanker loads carrying more than 1.7 million barrels of Napo, the new OCP crude oil blend.

"Ecuador has entered a new era in its economic and industrial development. The opening of the first privately owned and operated pipeline, where EnCana indirectly holds a 36 percent interest, is expected to attract new investment to the country. We are continuing to develop our existing land base and look for new lands to further expand our production," said Don Swystun, President of EnCana's Ecuador region.

EnCana increases stake in North Sea's Scott and Telford fields and takes over operatorship

On October 1, 2003, EnCana completed its acquisition of an additional 14 percent interest in each of the Scott and Telford oil fields. The company took over operatorship of the Scott Telford production platform on October 1 and now holds 27.5 percent of the Scott field and 34.2 percent of the Telford field. Net production is currently about 17,000 barrels of oil equivalent per day.

During the fourth quarter, the U.K. Department of Industry and Trade is expected to conclude its regulatory review of EnCana's development plan for the North Sea's Buzzard oil field, estimated to contain more than 400 million barrels of recoverable reserves. Preliminary selection of Aker Verdal of Norway to construct three steel jackets has been announced. Bids for additional components are being reviewed. Provided that regulatory and partner approval is received, Buzzard is expected to start production in late 2006. EnCana, the operator, holds approximately 43 percent of Buzzard, which is expected to produce about 75,000 barrels per day of light, royalty free oil net to EnCana at peak production.

Midstream & Marketing

EnCana's Midstream & Marketing division generated $19 million of operating cash flow in the third quarter of 2003. With the strong prices for natural gas through the first three quarters of 2003, and lower than expected seasonal price differentials during much of the year, EnCana has seen lower prices bid for storage capacity and reduced opportunities for storage optimization as compared to previous years.

During the year, the company changed its focus on the utilization of Midstream & Marketing's proprietary storage capacity. EnCana's proprietary production will not normally be injected into storage except to mitigate short-term operational or transportation constraints. Proprietary storage capacity will now be utilized by the company's gas storage business unit for optimization activities and third party contracting.

During the fourth quarter, the company anticipates Midstream & Marketing will achieve operating cash flow of approximately $40 million. Based on current forward market gas prices EnCana expects to capture significant margins on its winter withdrawals of storage optimization volumes, but more heavily weighted to realizations in the first quarter of 2004. Total operating cash flow from Midstream & Marketing for 2003 is now expected to be approximately $75 million, down from the previous estimate of $100 million to $130 million.

New Louisiana storage facility planned

EnCana Gas Storage is planning to build a new, high-deliverability gas storage facility in southwest Louisiana. Starks Gas Storage L.L.C., an indirect, wholly owned subsidiary of EnCana Gas Storage Inc., plans to develop the project by converting existing underground brine caverns into a gas storage facility with connections to a number of nearby, large-diameter gas transmission pipelines. Located approximately 25 miles west of Lake Charles, Louisiana, Starks plans to initially develop 8 billion cubic feet of gas storage capacity with a withdrawal rate of approximately 400 million cubic feet per day. Having completed the preliminary engineering work and secured the property rights, Starks is now seeking customers with an interest in booking capacity in the new facility. The project is anticipated to be fully in-service by the third quarter of 2005.

EnCana continues to pursue expansions of its continental gas storage network, primarily with the expansion of Wild Goose Storage in northern California, and the completion of the first phase of the Countess gas storage facility east of Calgary. The Wild Goose expansion, scheduled for completion in April 2004, will raise total working gas capacity by 10 billion cubic feet to approximately 24 billion cubic feet, plus expand daily withdrawal capability by 140 percent to 480 million cubic feet per day and daily injection capability more than fivefold to 450 million cubic feet per day. The first phase of the Countess facility, scheduled for start-up November 1 of this year, has 10 billion cubic feet of gas in inventory and available for withdrawal during the coming winter. Two additional phases of Countess are planned to take capacity to about 30 billion cubic feet in 2004 and 40 billion cubic feet in 2005.

FINANCIAL INFORMATION

NOTE: All financial information in this interim report reflects actual results, except for the company's 2002 pro forma nine-month financial results, which reflect the results of PanCanadian and AEC as if they had merged at the beginning of 2002. The actual statements for the first nine months of 2002 represent PanCanadian results alone during the first quarter of 2002 as the merger did not occur until the beginning of April 2002.

This interim report and EnCana's supplemental information, including convenience financial statements prepared in U.S. dollars, are posted on the company's Web site: www.encana.com.

Updated guidance

EnCana has posted an updated guidance document on its Web site.

ENCANA CORPORATION

EnCana is one of the world's leading independent oil and gas companies and North America's largest independent natural gas producer and gas storage operator. It has an enterprise value of approximately C$30 billion. Ninety percent of the company's assets are in four key North American growth platforms. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. Through its U.S. subsidiaries, EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deepwater Gulf of Mexico. International subsidiaries operate two key high potential international growth platforms: Ecuador, where it is the largest private sector oil producer, and the U.K. central North Sea, where it is the operator of a large oil discovery. EnCana and its subsidiaries also conduct high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's high performance benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

ADVISORY – In the interest of providing EnCana Corporation ("EnCana" or the "company") shareholders and potential investors with information regarding the company, certain statements throughout this news release constitute 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", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this news release include, but are not limited to, statements with respect to: projected cash taxes for 2003, 2004 and beyond; projected oil shipment volumes through the OCP Pipeline by the end of 2003 and in 2004 and beyond, and the impact of the OCP Pipeline on investment in Ecuador; the timing for completion of the various phases of the Countess, Wild Goose and Starks gas storage projects, and storage capacities, injection and withdrawal rates expected upon completion; the effect of certain forward contracts; the production, growth and growth potential, including the company's plans therefor, with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea and the Gulf of Mexico; projections relating to the company's coalbed methane and SAGD projects and initiatives; production and sales targets for oil, natural gas and natural gas liquids for 2003 and 2004; the timing for completion of regulatory review and the commencement of production from the Buzzard project, and expected production rates therefrom; the company's projected capital investment levels for 2003; projected operating costs and finding and development costs for 2003; the company's execution of share purchases under its Normal Course Issuer Bid; projections for wells and production to be tied into gathering systems during the fourth quarter of 2003, and production increases expected therefrom; projected unbooked resource potential available from various assets and initiatives; expectations regarding 2003/2004 winter gas prices; gas storage levels for 2003 and 2004; projected cash flow for 2003 from the Midstream & Marketing division; estimated sustainable capital investment, operating and administrative synergies; the projected per share growth rate for 2003; the projected sales growth rate for 2003 and 2004; the impact of the company's investment strategy on future share value; the company's estimate of its ability to convert unbooked resource potential to reserves; plans to report financial and operating results following U.S. protocols and in U.S. dollars; 2003 proved reserves replacement cost; projected future usage plans for the company's proprietary gas storage facilities; the projected profitability and margins which may be achieved from various projects and initiatives, including Cutbank Ridge and gas storage operations, and the timing for completion and capacity of the Ekwan Pipeline project.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve 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, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable reserves; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the company operates, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the company operates and international terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the company; the risk that the anticipated synergies to be realized by the merger of AEC and the company will not be realized; costs relating to the merger of AEC and the company being higher than anticipated and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Statements relating to "reserves", "resources", and "resource potential" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana 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. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this news release are made as of the date of this news release, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

ADVISORY – In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company, certain statements throughout this Management's Discussion and Analysis ("MD&A") constitute 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", "forecast", "target", "project" 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 oilsands strategy; projected royalty rates for 2003; projected federal and provincial taxes and tax rates for 2003 and the Company's expectations regarding current tax expense for 2003 and 2004; projected oil shipment volumes through the OCP pipeline by the end of 2003; the timing for completion of the various phases of the Countess and Wild Goose gas storage projects and storage capacities, injection and withdrawal rates expected upon completion; the effect of certain forward contracts on future capital funding requirements; the impact of pipeline capacity on AECO production area prices; the production and growth potential, including the Company's plans therefor, with respect to EnCana's various assets and initiatives, including assets and initiatives in North America, Ecuador, the U.K. central North Sea, the Gulf of Mexico and potential new ventures exploration growth platforms; production and sales targets for oil, natural gas and natural gas liquids for 2003 and 2004; the Company's projected capital investment levels for 2003 and the source of funding therefor; projected 2003 future development costs; the effect of the Company's risk management program; the Company's execution of share purchases under its Normal Course Issuer Bid; projections with respect to increased marketing of 19 degree API Napo blend and decreased marketing of 23 degree API Oriente blend; the impact of the Kyoto Accord on operating costs; and crude oil price volatility for 2003.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve 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, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations, including credit risks; imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved or probable reserves; the Company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's ability to secure adequate product transportation; changes in environmental and other regulations; political and economic conditions in the countries in which the Company operates, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company operates and international terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions brought against the Company; the risk that the anticipated synergies to be realized by the merger of AEC and the Company will not be realized; costs relating to the merger of AEC and the Company being higher than anticipated; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. 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 exist in the quantities predicted or estimated, and can be profitably produced in the future. Although EnCana 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. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this MD&A are made as of the date of this MD&A, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, 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.

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the unaudited interim Consolidated Financial Statements for the period ended September 30, 2003 and September 30, 2002 and the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2002.

The 2002 comparative figures included in the unaudited interim Consolidated Financial Statements ("Consolidated Financial Statements") for the nine months ended September 30, 2003 include the results of the Company prior to the April 5, 2002 merger with Alberta Energy Company Ltd. ("AEC"). As such, the amounts reported for the nine months ended September 30, 2002 do not include any results related to AEC's operations prior to April 5, 2002.

EnCana reports the results of its continuing operations under two main business segments: Upstream and Midstream & Marketing as further described in Note 3 to the Consolidated Financial Statements.

CONSOLIDATED FINANCIAL RESULTS

EnCana's 2003 third quarter cash flow from continuing operations was $1,347 million, or $2.80 per Common Share-Diluted ("per share"), an increase of 47 percent over $916 million, or $1.90 per share, in the corresponding quarter of 2002. Net earnings from continuing operations were $399 million, or $0.82 per share, an increase of 244 percent when compared to $116 million, or $0.24 per share, in the third quarter of last year. Comparatively higher commodity prices and growth in the Company's sales volumes over the same period in 2002 were the primary factors contributing to the increases.

For the nine months ended September 30, 2003, cash flow from continuing operations of $4,637 million, or $9.54 per share, increased 110 percent from $2,207 million, or $5.45 per share, in the same period last year. The Company's net earnings from continuing operations were $2,418 million, or $5.00 per share, an increase of 232 percent when compared to $729 million, or $1.80 per share, in the first nine months of 2002. In addition to continued higher commodity prices and growth in sales volumes, the improvement in the year-to-date cash flow results reflected the inclusion of post-merger operations for the full nine-month period in 2003. Net earnings for the nine months of 2003 also included a $486 million, or $1.00 per share, recovery of future income tax liabilities, recorded in the second quarter, resulting from the reductions in the Canadian federal and Alberta corporate income tax rates and an unrealized after-tax gain on the translation of U.S. dollar denominated debt of $406 million, or $0.83 per share.

Consolidated Financial Summary	Three Months Ended September 30		Nine Months Ended September 30	
($ millions, except per share amounts)	**2003**	2002	**2003**	2002
Revenues, Net of Royalties and Production Taxes	**$ 3,116**	$ 2,741	**$ 10,378**	$ 6,388
Net Earnings from Continuing Operations	**399**	116	**2,418**	729
– per share	**0.82**	0.24	**5.00**	1.80
Net Earnings	**400**	204	**2,712**	795
– per share	**0.82**	0.42	**5.60**	1.96
Cash Flow from Continuing Operations	**1,347**	916	**4,637**	2,207
– per share	**2.80**	1.90	**9.54**	5.45
Cash Flow	**1,352**	1,022	**4,642**	2,349
– per share	**2.81**	2.12	**9.55**	5.80

In accordance with Canadian generally accepted accounting principles ("GAAP"), the Company is required to translate long-term debt borrowed in Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings or, in the case of long-term debt held by self-sustaining foreign operations, in the foreign currency translation adjustment account included in Shareholders' Equity in the Consolidated Balance Sheet. In order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt on the Company's results, the following table has been prepared. The majority of these unrealized gains/losses relate to debt with maturity dates in excess of 5 years.

($ millions)	2003 Year-to-date	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2
Net Earnings from Continuing Operations, as reported	**$2,418**	**$ 399**	$1,063	$ 956	$ 374	$ 116	$ 482
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**406**	**14**	199	193	10	(145)	163
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt	**$2,012**	**$ 385**	$ 864	$ 763	$ 364	$ 261	$ 319
($ per Common Share - Diluted)							
Net Earnings from Continuing Operations, as reported	**$ 5.00**	**$ 0.82**	$ 2.20	$ 1.98	$ 0.77	$ 0.24	$ 1.02
Deduct: Foreign exchange gain/(loss) on translation of U.S. dollar debt (after-tax)*	**0.83**	**0.03**	0.41	0.40	0.02	(0.30)	0.35
Earnings from Continuing Operations, excluding foreign exchange on translation of U.S. dollar debt	**$ 4.17**	**$ 0.79**	$ 1.79	$ 1.58	$ 0.75	$ 0.54	$ 0.67

* As this is an unrealized gain/(loss), there is no impact on cash flow.

Earnings from Continuing Operations, excluding foreign exchange on the translation of U.S. dollar debt, and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this discussion and analysis in order to provide shareholders and potential investors with additional information regarding the Company's finances and results of operations.

ACQUISITIONS AND DIVESTITURES

On October 1, 2003, an EnCana U.K. subsidiary became the operator of the Scott and Telford fields marking the close of the sale and purchase agreements to exchange a 22.5 percent non-operated interest in the Llano field in the Gulf of Mexico for a 14 percent interest in both the Scott and Telford fields in the U.K. central North Sea. As a result, this EnCana U.K. subsidiary has become the largest working interest owner in both the Scott and Telford fields at 27.49 percent and 34.16 percent respectively.

On July 18, 2003, an EnCana U.S. subsidiary acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of approximately $128 million (US$91 million). Included in this acquisition were interests in developed and undeveloped reserves in Texas, U.S.A. which are currently producing approximately 21 million cubic feet of natural gas per day.

On January 31, 2003, the EnCana group of companies expanded their production and landholdings in Ecuador through the purchase of a corporation for net cash consideration of approximately $179 million (US$116 million). This acquisition included interests in developed and undeveloped reserves producing approximately 3,000 barrels of oil per day in three blocks adjacent to Block 15, where an Ecuadorian EnCana subsidiary has an existing non-operated working interest.

Discontinued Operations

Syncrude

On July 10, 2003, subsidiaries of the Company completed the sale of their remaining 3.75 percent working interest together with EnCana's gross-overriding royalty in the Syncrude Joint Venture for net cash consideration of approximately $427 million, subject to normal post-closing adjustments. The sale completed the Company's and its subsidiaries' disposition of their entire interest in the Syncrude project. The initial sale of the Company's 10 percent interest in the Syncrude project was completed on February 28, 2003 for net cash consideration of $1,026 million, before post-closing adjustments. There was no gain or loss on this sale. Net earnings from Syncrude operations were $1 million in the quarter, $31 million for the nine months ended September 30, 2003.

With the sale of the Syncrude interest completed, the Company intends to focus its oilsands strategy on developing its high quality bitumen resources, recovered through producing wells using steam-assisted gravity drainage (“SAGD”) technology, on 100-percent-owned and operated lands at Foster Creek and Christina Lake.

Midstream - Pipelines

Subsidiaries of the Company closed the sale of their interests in the Cold Lake Pipeline System and Express Pipeline System on January 2, 2003 and January 9, 2003, respectively, for total consideration of approximately $1.6 billion, including the assumption of related long-term debt. An after-tax gain on sale of $263 million was recorded in relation to these transactions.

These pipeline sales were part of EnCana’s strategic realignment to focus on its large portfolio of higher return growth assets. The proceeds were used for general corporate purposes, including debt reduction, prior to being re-deployed.

The Syncrude and Midstream - Pipelines operations described above have been accounted for as discontinued operations as described in Note 4 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

	Three Months Ended September 30		Nine Months Ended September 30	
(average for the period)	**2003**	2002	**2003**	2002
AECO Price *($ per thousand cubic feet)*	**$ 6.29**	$ 3.25	**$ 7.07**	$ 3.67
NYMEX Price *(US$ per million British thermal unit)*	**4.97**	3.18	**5.66**	2.97
WTI *(US$ per barrel)*	**30.21**	28.25	**30.94**	25.45
WTI/Bow River Differential *(US$ per barrel)*	**8.12**	5.38	**7.42**	5.35
WTI/Oriente Differential (Ecuador) *(US$ per barrel)*	**5.3**4	4.35	**5.57**	4.28
U.S./Canadian dollar exchange rate *(US$)*	**0.725**	0.640	**0.700**	0.637

Natural gas prices in the third quarter of 2003 were significantly higher than prices in the same period last year. The average AECO index price was $6.29 per thousand cubic feet, up 94 percent from $3.25 per thousand cubic feet in the third quarter of 2002. The NYMEX average price was also higher at US$4.97 per million British thermal unit, an increase of 56 percent over the third quarter of 2002. Average gas prices remained relatively strong in the third quarter as a result of concerns over storage inventories entering winter and a lack of confidence concerning prospects for North American supply growth. Gas prices in the third quarter dropped when compared to the second quarter due to reduced industrial demand and a reduction in gas-driven electricity generation caused by cooler summer temperatures. In addition to storage injection demands, colder weather experienced in the first quarter of 2003 contributed to the higher average gas prices for the first nine months of 2003.

The benchmark West Texas Intermediate (“WTI”) crude oil price was higher for both the third quarter of 2003 and the year-to-date in comparison with the prior year. The higher prices reflect the impact of continued low levels of world oil inventories, market uncertainty over Iraqi supply and OPEC’s management of its production levels.

Differentials between heavy and light crude oil prices continue to widen when comparing 2003 with 2002. Both the WTI/Bow River differential and the WTI/Oriente differential were wider when compared to the third quarter and the first nine months of last year. This was driven by lower asphalt demand in 2003, additional Canadian heavy crude oil coming on stream and increased freight rates on Oriente crude oil.

The Canadian dollar continued to strengthen relative to the U.S. dollar during the first nine months of 2003. The U.S./Canadian dollar exchange rate averaged US$0.725 per $1 Canadian in the third quarter, a reduction over the average rate of US$0.640 per $1 Canadian during the same period last year, closing at US$0.740 on September 30, 2003. The year-to-date U.S./Canadian dollar exchange rate averaged US$0.700 per $1 Canadian compared with an average of US$0.637 per $1 Canadian in the first nine months of 2002. The strengthening of the Canadian dollar is primarily the result of increased deficit concerns in the U.S. and the continuing difference between Canadian and U.S. interest rates. While the stronger Canadian dollar results in gains on the U.S. dollar denominated debt, it adversely impacts the average net Canadian dollar price realized by the Company on its sales of oil and natural gas, which are either directly denominated in U.S. dollars or denominated in Canadian dollars but closely tied to U.S. currency. The adverse impact in revenue is partially offset by operating and capital expenses denominated in U.S. dollars which lowers the Canadian dollar amounts paid for those goods and services.

RESULTS OF OPERATIONS

*Upstream**

Three Months Ended September 30

($ millions)	2003 Produced Gas & NGLs	2003 Crude Oil	2003 Non-Producing	2003 Total	2002 Produced Gas & NGLs	2002 Crude Oil	2002 Non-Producing	2002 Total
Revenues								
Gross revenue	$ 1,808	$ 530	$ 72	$ 2,410	$ 1,141	$ 661	$ 26	$ 1,828
Royalties and production taxes	310	63	–	373	138	118	–	256
Revenues, net of royalties and production taxes	1,498	467	72	2,037	1,003	543	26	1,572
Expenses								
Transportation and selling	133	25	–	158	92	34	–	126
Operating	154	139	64	357	141	120	35	296
Depreciation, depletion and amortization	484	229	3	716	393	182	4	579
Upstream Income	$ 727	$ 74	$ 5	$ 806	$ 377	$ 207	$ (13)	$ 571

Nine Months Ended September 30

($ millions)	2003 Produced Gas & NGLs	2003 Crude Oil	2003 Non-Producing	2003 Total	2002 Produced Gas & NGLs	2002 Crude Oil	2002 Non-Producing	2002 Total
Revenues								
Gross revenue	$ 5,886	$ 1,712	$ 181	$ 7,779	$ 2,675	$ 1,519	$ 61	$ 4,255
Royalties and production taxes	1,018	288	–	1,306	347	258	–	605
Revenues, net of royalties and production taxes	4,868	1,424	181	6,473	2,328	1,261	61	3,650
Expenses								
Transportation and selling	366	108	–	474	210	67	–	277
Operating	447	405	174	1,026	312	293	71	676
Depreciation, depletion and amortization	1,465	664	7	2,136	892	415	10	1,317
Upstream Income	$ 2,590	$ 247	$ –	$ 2,837	$ 914	$ 486	$ (20)	$ 1,380

* Upstream results exclude Syncrude operations, which have been accounted for as discontinued operations as described in Note 4 to the Consolidated Financial Statements.

Sales Volumes	Three Months Ended September 30 **2003**	Three Months Ended September 30 2002	Nine Months Ended September 30 **2003**	Nine Months Ended September 30 2002
Produced Gas *(million cubic feet per day)*	**2,961**	2,688	**2,966**	2,124
Crude Oil *(barrels per day)*	**223,337**	211,283	**211,868**	175,448
NGLs *(barrels per day)*	**28,404**	22,903	**29,785**	21,594
Total *(barrel of oil equivalent per day)**	**745,241**	682,186	**735,986**	551,042

* Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent

Revenue Variances for 2003 Compared to 2002 *($ millions)*	Three Months Ended September 30 Price	Three Months Ended September 30 Volume	Three Months Ended September 30 Total	Nine Months Ended September 30 Price	Nine Months Ended September 30 Volume	Nine Months Ended September 30 Total
Produced Gas and NGLs	$ 543	$ 124	$ 667	$ 2,153	$ 1,058	$ 3,211
Crude Oil	(169)	38	(131)	(122)	315	193
Total Gross Revenue*	$ 374	$ 162	$ 536	$ 2,031	$ 1,373	$ 3,404

* Excludes gross revenue from Non-Producing Operations

Consolidated Upstream Results

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry.

In the third quarter of 2003, gross revenue from the Company's upstream operations was $2,410 million, an increase of $582 million, or 32 percent, over gross revenue of $1,828 million in the third quarter of 2002. The quarter over quarter increase primarily reflected the benefit of higher realized natural gas prices and a 38 percent increase in natural gas sales from the Company's prospects in the U.S. Rockies.

Upstream gross revenue for the first nine months of 2003 was $7,779 million, up $3,524 million, or 83 percent, from the first nine months of last year. In addition to higher commodity prices, the increase in gross revenue reflected the inclusion of a full nine months of post-merger sales volumes, increased operations in the U.S. Rockies, expansion of the Company's SAGD projects and continued development in both Canada and the U.S. Rockies.

The following table provides a summary of royalties as a percentage of the Company's realized commodity prices, net of transportation and selling costs and excluding the impact of financial hedging:

Average Royalty Rates *(excluding the impact of financial hedging)*	Three Months Ended September 30		Nine Months Ended September 30	
	2003	2002	**2003**	2002
Produced Gas				
Canada	**15%**	12%	**14%**	13%
U.S.*	**20%**	23%	**20%**	21%
NGLs - North America	**21%**	15%	**20%**	13%
Crude Oil				
North America**	**11%**	13%	**12%**	13%
Ecuador	**30%**	37%	**34%**	36%
Total Upstream	**17%**	16%	**17%**	16%

* Excludes U.S. production taxes of approximately 8 percent.

** Excludes impact of amendments related to prior years which reduced royalties by $21 million.

As shown in the table above, average royalties were 17 percent in the third quarter basically unchanged when compared to the corresponding period in 2002. For the nine months ended September 30, 2003, royalties averaged 17 percent compared with 16 percent in the same period of 2002. The reduction in the Ecuadorian royalties for the third quarter is due to lower realized prices. This year-to-date rate is on track with the Company's expectations, which anticipate a royalty rate of 18 percent for 2003.

Transportation and selling costs totalled $158 million in the quarter and $474 million for the year-to-date, compared with costs of $126 million and $277 million in the respective periods of 2002. The higher costs are primarily the result of higher sales volumes in 2003. For the purpose of the revenue discussions below, these costs have been netted against gross revenue in calculating the per unit realized price for each commodity.

Upstream operating expenses, excluding costs related to non-producing activities, were $293 million in the third quarter, an increase of $32 million over the third quarter of 2002 primarily due to higher levels of production in 2003. On a per unit basis, operating expenses, including cost recoveries, were $4.14 per barrel of oil equivalent in the quarter up from $4.00 per barrel of oil equivalent in the same quarter of last year. The increase is mainly due to maintenance, workovers, higher fuel and power costs due to higher natural gas prices, combined with increased production weighting from SAGD projects and higher per unit costs in the U.K. due to decreased sales volumes.

In the first nine months of the year, upstream operating expenses, excluding costs related to non-producing activities, were $852 million compared with costs of $605 million in the same period of 2002. Inclusion of the full nine months of post-merger production and 2002 acquisitions by subsidiaries in the U.S. Rockies, expansion of the SAGD projects and continued development in both Canada and the U.S. Rockies were the primary factors contributing to the increase. For the year-to-date, these costs, including cost recoveries, were $4.10 per barrel of oil equivalent, which compared with $3.94 per barrel of oil equivalent in the first nine months of 2002. Increases in maintenance costs, workovers, fuel and electricity costs due to higher natural gas prices, combined with increased production weighting from SAGD projects and higher per unit costs in the U.K. due to lower sales volumes, resulted in higher upstream unit operating expenses.

Depreciation, depletion and amortization ("DD&A") charges totalled $716 million, or $10.44 per barrel of oil equivalent, in the third quarter of 2003 compared with $579 million, or $9.23 per barrel of oil equivalent, in the same quarter last year. For the first nine months of 2003, DD&A charges amounted to $2,136 million, or $10.63 per barrel of oil equivalent, up from $1,317 million, or $8.75 per barrel of oil equivalent in the same period of 2002. The 2003 DD&A rates reflect increased future development costs related to the proven reserves added for SAGD projects and the U.S. Rockies. The 2003 future development costs are approximately $2.30 per barrel of oil equivalent of the DD&A calculation compared to $0.83 per barrel of oil equivalent in 2002.

Produced Gas and NGLs

Per-Unit Results – Produced Gas and NGLs

Three Months Ended September 30	Produced Gas - Canada		Produced Gas - U.S.		NGLs - North America	
	2003	2002	**2003**	2002	**2003**	2002
	($ per thousand cubic feet)		*($ per thousand cubic feet)*		*($ per barrel)*	
Price, net of transportation and selling	**$ 5.80**	$ 3.24	**$ 6.11**	$ 3.16	**$ 33.10**	$ 31.18
Royalties	**0.85**	0.39	**1.73**	0.99	**6.79**	4.62
Operating expenses	**0.58**	0.58	**0.36**	0.34	**–**	–
Netback excluding hedging	**4.37**	2.27	**4.02**	1.83	**26.31**	26.56
Financial Hedge	**(0.04)**	0.29	**(0.17)**	0.57	**–**	–
Netback including hedging	**$ 4.33**	$ 2.56	**$ 3.85**	$ 2.40	**$ 26.31**	$ 26.56
	(MMcf/d)		*(MMcf/d)*		*(bbls/d)*	
Sales Volumes	**2,197**	2,129	**757**	550	**27,975**	22,927

Nine Months Ended September 30	Produced Gas - Canada		Produced Gas - U.S.		NGLs - North America	
	2003	2002	**2003**	2002	**2003**	2002
	($ per thousand cubic feet)		*($ per thousand cubic feet)*		*($ per barrel)*	
Price, net of transportation and selling	**$ 6.71**	$ 3.64	**$ 6.57**	$ 3.36	**$ 36.01**	$ 27.99
Royalties	**0.97**	0.48	**1.89**	0.99	**7.35**	3.76
Operating expenses	**0.59**	0.55	**0.31**	0.39	–	–
Netback excluding hedging	**5.15**	2.61	**4.37**	1.98	**28.66**	24.23
Financial Hedge	**(0.34)**	0.13	**0.11**	0.33	**–**	–
Netback including hedging	**$ 4.81**	$ 2.74	**$ 4.48**	$ 2.31	**$ 28.66**	$ 24.23
	(MMcf/d)		*(MMcf/d)*		*(bbls/d)*	
Sales Volumes	**2,246**	1,762	**709**	352	**29,059**	20,745

Gross revenue from sales of produced gas and NGLs was $1,808 million in the third quarter of 2003, an increase of $667 million, or 58 percent, over the same quarter last year. Higher natural gas and NGL commodity prices and increased sales volumes were the primary contributing factors to the increase in gross revenue. Natural gas revenues in the quarter were reduced by $20 million due to financial currency and commodity hedging activities, which compared to a gain of $86 million in the third quarter of 2002.

In the first nine months of 2003, gross revenue from sales of produced gas and NGLs was $5,886 million, an increase of $3,211 million, or 120 percent, over the corresponding period last year. The increase in 2003 results reflected higher commodity prices and sales volumes, as well as the inclusion of post-merger results for the full nine-month period. Natural gas and NGL gross revenue, for the nine months, was reduced by $187 million from financial currency and commodity hedging activities. This compared with a net gain of $95 million on financial transactions in the first nine months of last year.

Produced gas sales volumes in the quarter averaged 2,961 million cubic feet per day, up 10 percent from sales of 2,688 million cubic feet per day in the third quarter of last year. NGLs sales volumes were 28,404 barrels per day, up 24 percent from sales volumes of 22,903 barrels per day in the corresponding quarter of 2002. The higher 2003 sales volumes were primarily the result of continued development successes at Jonah, Mamm Creek, Suffield and Greater Sierra combined with acquisitions by subsidiaries in the U.S. Rockies region. Canadian gas production growth has been impacted by the short winter, wet spring and greater than expected declines in the Ladyfern area.

During the first nine months of the year, produced gas sales volumes rose to 2,966 million cubic feet per day, a 40 percent increase over 2002 levels for the same period. NGL sales volumes were also higher at 29,785 barrels per day compared to sales volumes of 21,594 barrels per day in the first nine months of 2002. In addition to the continued development and acquisitions in the U.S. Rockies region previously mentioned, the increase in the year-to-date sales volumes also reflected the added volumes for the full nine months of the year from the merger with AEC.

In addition to growth in the Company's natural gas and NGLs sales volumes, gross revenue also increased as a result of stronger commodity prices. Realized natural gas sales prices in Canada averaged $5.80 per thousand cubic feet in the quarter, a 79 percent improvement over an average price of $3.24 per thousand cubic feet in the third quarter of 2002. The realized price for natural gas in the U.S. was also higher at $6.11 per thousand cubic feet, an increase of 93 percent over $3.16 per thousand cubic feet in the same quarter last year. Increases in the natural gas prices are primarily the result of record gas storage injection demands and cooler weather experienced in the early part of 2003. The average North American NGL price for the quarter was $33.10 per barrel, up 6 percent from $31.18 per barrel in the third quarter of 2002.

High commodity prices resulted in stronger realized natural gas and NGL prices on a year-to-date basis. The realized Canadian natural gas sales price averaged $6.71 per thousand cubic feet compared to an average price of $3.64 per thousand cubic feet in the first nine months of 2002. The realized price for natural gas in the U.S. was $6.57 per thousand cubic feet, which compared with $3.36 per thousand cubic feet in the first nine months of 2002. The average North American NGL price for the year-to-date was up 29 percent to $36.01 per barrel.

Produced gas operating expenses in Canada, net of operating recoveries, in the quarter were $0.58 per thousand cubic feet, unchanged from the same quarter of 2002. For the year-to-date, these costs were $0.59 per thousand cubic feet, which compared with $0.55 per thousand cubic feet in the same period last year. Higher Canadian operating costs, year over year, resulted from increased maintenance, workovers, higher processing fees and increased production from higher operating cost areas.

In the U.S. Rockies, produced gas operating expenses, net of operating recoveries, averaged $0.36 per thousand cubic feet in the third quarter of 2003, an increase over costs of $0.34 per thousand cubic feet in the same quarter of 2002. For the nine months ended September 30, 2003, these costs were $0.31 per thousand cubic feet, down 21 percent from $0.39 per thousand cubic feet in the same period last year. Year-over-year unit operating costs in the U.S. benefited from the addition of lower operating cost properties at Jonah and Mamm Creek.

Crude Oil

Per-Unit Results – Crude Oil

Three Months Ended September 30	North America		Ecuador		United Kingdom	
($ per barrel)	**2003**	2002	**2003**	2002	**2003**	2002
Price, net of transportation and selling	**$ 27.09**	$ 32.38	**$ 28.40**	$ 33.59	**$ 35.79**	$ 39.30
Royalties*	**2.87**	4.07	**8.59**	12.51	**–**	–
Operating expenses	**7.61**	6.66	**4.45**	4.60	**9.03**	5.71
Netback excluding hedging	**16.61**	21.65	**15.36**	16.48	**26.76**	33.59
Financial Hedge	**(4.00)**	(0.89)	**–**	–	**–**	–
Netback including hedging	**$ 12.61**	$ 20.76	**$ 15.36**	$ 16.48	**$ 26.76**	$ 33.59
Sales Volumes *(bbls/d)*	**164,410**	146,142	**53,543**	55,579	**5,384**	9,562

* North America excludes the impact of amendments related to prior years which reduced royalties by $21 million.

Nine Months Ended September 30	North America		Ecuador		United Kingdom	
($ per barrel)	**2003**	2002	**2003**	2002	**2003**	2002
Price, net of transportation and selling	**$ 30.70**	$ 30.17	**$ 33.27**	$ 32.58	**$ 38.37**	$ 35.83
Royalties*	**3.72**	3.93	**11.47**	11.61	**–**	–
Operating expenses	**7.58**	6.56	**5.28**	5.17	**6.27**	3.80
Netback excluding hedging	**19.40**	19.68	**16.52**	15.80	**32.10**	32.03
Financial Hedge	**(5.25)**	(0.99)	**–**	(0.01)	**–**	(0.11)
Netback including hedging	**$ 14.15**	$ 18.69	**$ 16.52**	$ 15.79	**$ 32.10**	$ 31.92
Sales Volumes *(bbls/d)*	**155,464**	126,159	**48,667**	38,685	**7,737**	10,604

* North America excludes the impact of amendments related to prior years which reduced royalties by $21 million.

In the third quarter of 2003, gross revenue from the sale of crude oil was $530 million, down 20 percent from $661 million in the same quarter last year. The decline in gross revenue was the result of lower realized prices and an increase in costs related to financial hedging. Crude oil gross revenue in the quarter was reduced by a cost of approximately $61 million resulting from financial commodity and currency hedging. This compared with a cost of $12 million in the third quarter of 2002.

Gross revenue from the sale of crude oil for the first nine months of 2003 was $1,712 million, an increase of 13 percent over gross revenue of $1,519 million for the same period last year. The higher gross revenue reflected higher oil sales volumes, which were mainly the result of increased production from the Company's SAGD projects, higher average realized sales prices and the inclusion of post-merger volumes for the full nine month period. Crude oil gross revenue in the first nine months of 2003 was reduced by approximately $223 million as a result of financial commodity and currency hedging, which compared with a reduction of $34 million in the same period of 2002.

North America crude oil sales rose 13 percent, averaging 164,410 barrels per day in the quarter, compared with sales of 146,142 barrels per day in the same quarter of 2002. The increase in sales volumes reflected continued development at Suffield and Pelican Lake, commencement of commercial production at Christina Lake and increased production at Foster Creek.

North America crude oil sales were also higher on a year-to-date basis, averaging 155,464 barrels per day in 2003 compared with 126,159 barrels per day in the first nine months of 2002. The improvement in sales reflected the increase in volumes related to the Company's SAGD projects, continued development at Suffield, as well as the inclusion of the full nine months of post-merger sales volumes in 2003.

World oil prices continued to be strong in the first nine months of 2003. The Company's realized price from North America crude oil averaged $27.09 per barrel in the quarter and $30.70 per barrel in the first nine months of 2003. This compared with realized prices of $32.38 per barrel and $30.17 per barrel in the respective periods of 2002. Low levels of oil inventories, continued uncertainty over Iraq oil shipments and management of production volumes by the OPEC members has contributed to the increase in the higher average US$ per barrel WTI price in the first nine months of 2003.

In the third quarter of 2003, unit operating costs for North America crude oil averaged $7.61 per barrel, up 14 percent from $6.66 per barrel in the third quarter of 2002. For the nine months ended September 30, 2003, these costs averaged $7.58 per barrel compared with an average cost of $6.56 per barrel in the same period of 2002. The higher unit operating expenses in 2003 were due to higher maintenance costs and higher fuel and electricity costs resulting from the rise in natural gas prices combined with increased production from the SAGD projects at Foster Creek and Christina Lake.

Crude oil production in Ecuador averaged 73,760 barrels per day during the quarter, up from 52,344 barrels per day in the same quarter of 2002. In the third quarter of 2003, the Company continued to transfer crude oil to the Oleoducto de Crudos Pesados ("OCP") with 6,805 barrels per day of crude oil being transferred for use by OCP in asset commissioning. Sales of Ecuador crude oil were 53,543 barrels per day, including an under lifting of 13,412 barrels per day, which compared with sales of 55,579 barrels per day and over lifting of 3,235 barrels per day in the third quarter of last year. In mid-September, the Company's Ecuadorian subsidiary had its first lifting from the new OCP Marine Terminal at Balao. With the completion of the OCP pipeline, Ecuador production volumes are no longer transportation constrained and, as a result, September 2003 production exceeded 96,000 barrels per day. Sales of Ecuador crude oil were higher on a year-to-date basis over 2002 due to the inclusion of a full nine months of volumes in 2003.

The average realized price for Ecuador crude oil was $28.40 per barrel in the quarter and $33.27 per barrel for the year-to-date which compared to an average price of $33.59 per barrel and $32.58 for the comparative periods of last year. Unit operating costs were $4.45 per barrel in the quarter, down slightly from $4.60 per barrel in the third quarter of 2002. These costs were $5.28 per barrel in the first nine months of the year compared with $5.17 per barrel in the same period last year.

Sales of U.K. crude oil averaged 5,384 barrels per day in the quarter and 7,737 barrels per day for the year-to-date, which compared with sales of 9,562 barrels per day and 10,604 barrels per day in the respective periods last year. Production declines were expected due to the natural declines of the fields and platform maintenance in the third quarter. This resulted in an increase in per unit operating costs, which were $9.03 per barrel in the quarter and $6.27 per barrel for the year-to-date. In comparison, 2002 unit operating costs were $5.71 per barrel in the third quarter and $3.80 per barrel for the nine months ended September 30.

Non-producing activities added $72 million in revenues for the third quarter and $181 million year-to-date, and included activities that do not result directly in the production of oil and gas. These activities include revenue from third party gas processing, gas gathering and electrical generation.

Midstream & Marketing

Midstream Financial Results*

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2003**	2002	**2003**	2002
Gross Revenue	**$ 248**	$ 156	**$ 940**	$ 386
Expenses				
Operating	**79**	48	**272**	181
Purchased product	**155**	72	**613**	123
Depreciation, depletion and amortization	**10**	9	**27**	33
	$ 4	$ 27	**$ 28**	$ 49

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 4 to the Consolidated Financial Statements.

Gross revenue from continuing midstream operations increased to $248 million in the quarter, up from $156 million in the same quarter of 2002 due primarily to higher commodity prices. Despite higher gross revenue, financial results continued to be negatively impacted by short-term commodity price factors. Narrower summer/winter price spreads have resulted in lower revenues from third-party gas storage contracts and reduced margins from optimization activities. Relatively higher feedstock prices and reduced seasonal demand for propane decreased natural gas processing margins.

Marketing Financial Results* – by Product

Three Months Ended September 30	Gas		Crude Oil & NGLs		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Gross Revenue	**$ 502**	$ 448	**$ 327**	$ 561	**$ 829**	$ 1,009
Expenses						
Transportation and selling	**5**	38	**10**	10	**15**	48
Operating	**4**	2	**5**	4	**9**	6
Purchased product	**490**	429	**310**	540	**800**	969
Depreciation, depletion and amortization	**2**	1	**–**	–	**2**	1
	$ 1	$ (22)	**$ 2**	$ 7	**$ 3**	$ (15)

Nine Months Ended September 30	Gas		Crude Oil & NGLs		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Gross Revenue	**$ 1,693**	$ 1,066	**$ 1,268**	$ 1,283	**$ 2,961**	$ 2,349
Expenses						
Transportation and selling	**13**	64	**50**	39	**63**	103
Operating	**62**	2	**12**	10	**74**	12
Purchased product	**1,645**	967	**1,200**	1,227	**2,845**	2,194
Depreciation, depletion and amortization	**3**	8	**–**	–	**3**	8
	$ (30)	$ 25	**$ 6**	$ 7	**$ (24)**	$ 32

* Results of the Midstream & Marketing segment exclude financial results related to discontinued operations as described in Note 4 to the Consolidated Financial Statements.

EnCana's Marketing operations include market activities to optimize the value from the Company's proprietary production, including the management of transportation commitments not utilized for its own production. During the third quarter of 2003, gross revenue was $829 million, down from gross revenue of $1,009 million in the same quarter last year. For the nine months ended September 30, 2003, gross revenue from the Company's marketing activity was up $612 million to $2,961 million over the same period of last year. This increase largely reflected the inclusion of a full nine months of AEC volumes and the higher commodity prices experienced across the energy industry in the first nine months of 2003.

Corporate

Administrative expenses totalled $56 million in the quarter and $172 million for the year-to-date. This compared with $50 million and $111 million in the respective periods of 2002. The increase reflected the inclusion of the full nine months of post-merger operations. In 2003, the Company incurred higher governance, salary and consultant costs. On a per unit basis, administrative costs were $0.82 per barrel of oil equivalent in the quarter, compared with $0.80 per barrel of oil equivalent in the third quarter of last year. For the first nine months these costs were $0.86 per barrel of oil equivalent, which compared to $0.74 per barrel of oil equivalent in the same period last year.

Net interest expense of $87 million was down from $112 million in the third quarter of 2002. The lower interest expense reflected lower debt levels in the third quarter of 2003. For the first nine months of the year, net interest expense amounted to $257 million, which compared with $242 million for the same period in 2002. The higher nine-month net interest expense resulted primarily from the additional expense associated with the comparatively higher average debt level outstanding during the period in 2003. The AEC debt balances were excluded for the first quarter of 2002.

A foreign exchange gain of $25 million was recorded in the third quarter of 2003. This compared with a loss of $156 million in the corresponding quarter of last year. A foreign exchange gain of $560 million was included in the Company's results for the first nine months of the year, which compared with a gain of $24 million in the same period of 2002. The majority of the foreign exchange gain, $511 million, resulted from the translation of U.S. dollar denominated debt into Canadian dollars at the period-end exchange rate. Any exchange gains and losses resulting from this translation are recorded in earnings in the period they arise.

The provision for income tax resulted in an expense of $278 million in the quarter, and an expense of $513 million for the year-to-date. This compared to expenses of $126 million and $361 million in the respective periods of 2002. The 2003 provision for nine months includes a $486 million decrease in future income tax liabilities resulting from the reductions in the Canadian federal and Alberta corporate income tax rates and related changes to the resource allowance deduction. These changes were substantively enacted during the second quarter of 2003. The federal tax rate, which was reduced in other industries in 2000, is to be reduced by seven percentage points over the period 2003-2007, in addition the resource allowance deduction is to be phased out and replaced with a deduction for crown royalties paid, over the same period. The Alberta tax rate was reduced by one half of one percentage point. The effective tax rate for 2003 is expected to be 34 to 36 percent before considering the effect of the reduction in Canadian and Alberta tax rates and the unrealized gain or loss on the translation of U.S. dollar debt. The current tax expense was $75 million for the quarter and $38 million for the nine months ended September 30, 2003.

LIQUIDITY AND CAPITAL RESOURCES

Third quarter cash flow from continuing operations was $1,347 million, up from $916 million in the same quarter of 2002. Cash flow from continuing operations for the first nine months of 2003 was $4,637 million, $2,430 million higher than $2,207 million for the same period last year. The increased cash flow from continuing operations was primarily the result of higher revenues resulting from the Company's growth in sales volumes and stronger commodity prices. Cash flow in the first nine months of 2003 was also impacted by the inclusion of the full nine months of post-merger results.

EnCana's net debt, adjusted for working capital and including preferred securities was $7,198 million at September 30, 2003 compared with $6,130 million at December 31, 2002. The working capital at September 30, 2003, was $454 million and $1,848 million at December 31, 2002, of which $1,664 million related to the net assets and liabilities of Discontinued Operations. The increase in net debt was the result of higher capital spending and general operating requirements offset in part by proceeds from the dispositions of the Syncrude, Cold Lake and Express Pipeline Systems interests, and cash flow in excess of amounts paid for the Normal Course Issuer Bid. The strengthening of the Canadian dollar relative to the U.S. dollar resulted in an unrealized year-to-date gain of $511 million before tax on the translation of U.S. dollar debt and the corresponding reduction to the debt level as at September 30, 2003.

On October 2, 2003, the Company issued US$500 million notes due in 10 years at 4.75 percent. The proceeds from this issue were used primarily to repay existing bank and commercial paper indebtedness.

Net debt-to-capitalization, including all preferred securities, was 33 percent, up from 31 percent at December 31, 2002. Net debt-to-EBITDA was 1.1 times the trailing 12-month cash flow at the end of the quarter. As at September 30, 2003, the Company had available unused committed bank credit facilities in the amount of $1,784 million. Available unused committed bank credit facilities increased significantly after October 2, 2003 due to the receipt of proceeds from the US$500 million notes mentioned previously.

At December 31, 2002, the Company had $457 million in preferred securities of a subsidiary recorded as a liability on its balance sheet. These preferred securities are unsecured junior subordinated debentures and were recorded as a liability of the Company following the merger with AEC. On January 1, 2003, these preferred securities became the direct obligation of EnCana as a result of the amalgamation of the Company with AEC and, accordingly, are now recorded under the shareholders' equity section of the Consolidated Balance Sheet.

In October 2002, the Company received regulatory approval, under Canadian securities laws, to make a Normal Course Issuer Bid. Under the bid, EnCana was able to purchase for cancellation up to 23,843,565 of its Common Shares in the open market, representing five percent of the approximately 476,871,300 Common Shares then outstanding. During the third quarter, the Company purchased and paid for 15,281,500 Common Shares at an average price of $50.46 per Common Share. As of the expiry of the bid, on October 21, 2003, the Company had purchased for cancellation a total of 20,224,400 Common Shares at an average price of $50.35 per Common Share under this program.

On October 20, 2003, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 22, 2003. Under this bid, EnCana is able to purchase for cancellation up to 23,212,341 of its Common Shares, representing five percent of the approximately 464,246,813 Common Shares outstanding as of October 14, 2003. Purchases under the program must terminate on October 21, 2004 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the Toronto Stock Exchange. As of October 27, 2003, the Company has not purchased any Common Shares under the new bid.

Capital Expenditures

The Company's consolidated capital expenditures were $1,849 million in the quarter, up $409 million from the third quarter of 2002. Capital expenditures for the first nine months of the year of $4,880 million compared with expenditures of $3,311 million in the first nine months of 2002. The majority of expenditures in both 2003 and 2002 were directed towards natural gas exploration and development in North America. The Company's capital investment for the quarter and year-to-date was funded by cash flow in excess of amounts paid for the Normal Course Issuer Bid, proceeds received on the dispositions of the Syncrude interest, interests in the Cold Lake and Express Pipeline Systems and debt.

The following table provides a summary of the Company's capital spending, excluding dispositions and corporate acquisitions, on a divisional basis:

Capital Expenditures*	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2003**	2002	**2003**	2002
Upstream				
Canada	**$ 1,238**	$ 359	**$ 3,250**	$ 1,406
United States	**384**	876	**885**	1,500
Ecuador	**90**	96	**247**	168
United Kingdom	**26**	41	**64**	103
Other Countries	**21**	27	**89**	66
Total Upstream	**1,759**	1,399	**4,535**	3,243
Midstream & Marketing	**80**	22	**290**	39
Corporate	**10**	19	**55**	29
Total	**$ 1,849**	$ 1,440	**$ 4,880**	$ 3,311

* Excludes cash proceeds on dispositions of approximately $2.4 billion.

Upstream Capital Expenditures

Upstream capital expenditures totalled $1,759 million in the third quarter of 2003, up from $1,399 million in the same quarter last year. Capital spending on the Company's upstream operations for the year-to-date was $4,535 million, up from $3,243 million in the first nine months of 2002. The majority of 2003 expenditures related to North American properties, with spending in Canada directed primarily towards exploration and development of natural gas properties at Suffield and the Palliser Block in Alberta and Greater Sierra and Cutbank Ridge in northeast British Columbia. Capital expenditures in the United States focused primarily on natural gas exploration and development at Jonah and Mamm Creek.

Midstream & Marketing Capital Expenditures

In the first nine months of 2003, capital expenditures in the Midstream & Marketing segment were $290 million, of which $80 million was spent during the third quarter. This compared with $39 million for the first nine months of 2002. Expenditures in the first nine months of 2003 related primarily to ongoing improvements to midstream facilities, the construction of the Countess gas storage facility and the expansion of the Wild Goose storage facility. Year-to-date capital spending also included approximately $70 million related to equipment operating lease buyouts.

The Company has completed gas injections into the first 10 billion cubic feet of new storage capacity at Countess. The second and third phases of the Countess storage facility are expected to take total capacity to about 40 billion cubic feet by the second quarter of 2005. The expansion of the Wild Goose storage facility is expected to increase withdrawal capability from 200 million cubic feet per day to 320 million cubic feet per day in November 2003. By April 2004, withdrawal capacity will be further increased to 480 million cubic feet per day while injection capacity is expected to rise from 80 million to 450 million cubic feet per day and total working gas inventory capacity will increase from 14 billion cubic feet to 24 billion cubic feet.

In early July, a subsidiary of the Company increased its equity interest in the OCP Pipeline in Ecuador from 31.4 percent to 36.3 percent. The OCP Pipeline completed and passed performance testing during the week of October 13, 2003. OCP expects to be shipping 220,000 barrels per day by year-end with increasing volumes as field productivity increases in coming years. The shippers in total have a commitment to pay for shipping 350,000 barrels per day. As a result of using the OCP to transport its crude oil, the Company expects to increase the marketing of 19 degree API Napo blend and reduce the marketing of the 23 degree API Oriente blend.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company and its subsidiaries have entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements as outlined in the December 31, 2002 audited Consolidated Financial Statements and MD&A. As of September 30, 2003, these commitments, excluding debt obligations and preferred securities, had decreased by approximately $2 billion from December 31, 2002, to approximately $6 billion. The reduction in commitments reflects the impact of the sale of the Syncrude interest, the strengthening of the U.S./Canadian dollar exchange rate and the buyout of several equipment leases.

Discontinued Merchant Energy Operations

In July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") on a previously disclosed CFTC investigation. The investigation related to alleged inaccurate reporting of natural gas trading information during 2000 and 2001 by former employees of WD's now discontinued Houston-based merchant energy trading operation to energy industry publications that compiled and reported index prices. All Houston-based merchant energy trading operations were discontinued following the merger in 2002. Under the terms of the settlement, WD agreed to pay a civil monetary penalty in the amount of US$20 million without admitting or denying the findings in the CFTC's order.

The Company and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California and, along with other energy companies, are defendants in seven class action lawsuits in California and two class action lawsuits filed in the United States District Court in New York. The California lawsuits relate to sales of natural gas in California from 1999 to the present and contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws to artificially raise the price of natural gas through various means including the illegal sharing of price information through online trading, price indices and wash trading. The New York lawsuits claim that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the New York Mercantile Exchange from 2000 to 2002. The Gallo complaint claims damages in excess of US$30 million, before potential trebling under California laws. As is customary, the class actions do not specify the amount of damages claimed.

The Company and WD intend to vigorously defend against these claims; however, the Company cannot predict the outcome of these proceedings, whether these proceedings would lead to monetary damages which could have a material adverse effect on the Company's financial position, or whether there will be other actions arising out of these allegations on behalf of the same or different classes.

RISK MANAGEMENT

The Company's results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. Certain exposures are managed through the use of various derivative instruments and contracts, which are governed under formal policies approved by senior management, and are subject to limits established by the Board of Directors.

This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates and enhancing the probability of achieving corporate performance targets.

As a means of managing commodity price volatility in its producing areas and to ensure greater certainty in cash flow generation for its capital program, the Company has entered into various financial agreements and physical contracts. These transactions have fixed the oil and gas prices for a portion of the Company's future production.

Natural Gas

The Company entered into fixed price AECO and NYMEX swaps and AECO and NYMEX collars as a means of protecting corporate cash flow to ensure sufficient funds for capital expenditure programs. To protect weakening production area prices, the Company has entered into AECO and Rockies basis transactions. AECO production area prices may be negatively impacted as large amounts of contracted capacity on pipelines moving gas to downstream markets come up for renewal over the next several years. To manage exposure to transportation capacity on the Alliance Pipeline, the Company has entered into fixed price purchase and sale contracts.

Crude Oil

The Company has managed the WTI NYMEX price for a portion of its oil production with fixed price swaps and costless collars.

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments and physical contracts at various locations and terms over the next 13 months to manage the price volatility of the corresponding physical transactions and inventories. The financial instruments used included futures, fixed for floating swaps and basis swaps.

The following table summarizes the unrecognized gains/(losses) on the Company's risk management activities at September 30, 2003:

	Contract Maturity			
($ millions)	2003	2004	2005–2007	Total
Natural Gas	$ 9	$ 201	$ 164	**$ 374**
Crude Oil	(42)	(182)	–	**(224)**
Gas Storage Optimization	39	43	–	**82**
Power	2	2	–	**4**
Foreign Currency Risk	19	4	–	**23**
Interest Rate Risk	5	27	27	**59**
Total	$ 32	$ 95	$ 191	**$ 318**

Further details regarding the above risk management activities can be found in Note 10 to the Consolidated Financial Statements.

Kyoto Protocol

In December 2002, the Canadian Federal Government ratified the Kyoto Accord ("Accord") committing Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 - 2012. The Accord becomes effective once ratification from at least 55 Parties to the Convention representing 55 percent of Annex I Party emissions is obtained. Currently there is uncertainty surrounding whether or not the Accord will enter into force. The upstream oil and gas sector is currently in discussions with various levels of provincial and federal governments regarding the development of greenhouse gas regulations for the industry. It is premature to predict what impact these potential regulations could have on the sector but it is possible that the Company would face minor increases in operating costs in order to comply with a greenhouse gas emissions reduction target. The federal government has also committed to several important principles that will continue to protect the competitiveness of the oil and gas industry beyond 2012, including a 10 year target lock-in period for new projects and additional flexibility mechanisms for achieving compliance.

OUTLOOK

EnCana plans to continue to focus on growing natural gas production and storage capacity in North America and crude oil production in Canada and Ecuador to deliver near-term growth while building the U.K. central North Sea and the Gulf of Mexico oil growth platforms for expected medium and longer term growth. The Company also plans to continue its efforts to expand its medium and long-term growth prospects through new ventures exploration.

The Company's 2003 forecast for produced gas sales remains at between 3.0 and 3.1 billion cubic feet per day and between 3.25 and 3.45 billion cubic feet per day for 2004. Crude oil and natural gas liquids sales volumes for 2003 continue to be forecast at between 240,000 and 280,000 barrels per day and between 265,000 and 310,000 barrels per day for 2004.

Strong storage injection requirements combined with reduced U.S. and Canadian supply have tightened the balance between supply and demand resulting in higher average natural gas prices in 2003. The outlook for the fourth quarter and beyond will be principally impacted by weather and economic activity.

Volatility in crude oil prices is expected to continue in 2003 as a result of market uncertainties over the reintegration of Iraqi production, political issues in Venezuela and Nigeria, OPEC compliance with production quotas and the overall health of the world economies.

The Company expects 2003 capital investment in core programs to be approximately $5.9 billion before acquisitions and divestitures ($3.4 billion net of divestitures). It is anticipated that the capital program will be funded from cash flow and proceeds from the divestitures of non-core assets.

EnCana's estimate of normalized annual cash tax expense, with its current projected production, commodity prices, capital investment and exchange rate profile, is about $500 million per year. Largely as a result of the business reorganization arising from the merger, this pattern has shifted for 2003 and 2004. In 2003, cash taxes are expected to be about $400 million lower than the normalized level, while 2004 cash taxes are expected to be higher by a similar amount. For 2005, the company is expected to return to more normalized annual levels of cash tax.

October 27, 2003

EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

For the period ended September 30, 2003

		September 30			
		Three Months Ended		Nine Months Ended	
($ millions, except per share amounts)		**2003**	2002	**2003**	2002
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	*(Note 3)*	**$ 3,116**	$ 2,741	**$ 10,378**	$ 6,388
EXPENSES	*(Note 3)*				
Transportation and selling		**173**	174	**537**	380
Operating		**445**	350	**1,372**	869
Purchased product		**955**	1,041	**3,458**	2,317
Administrative		**56**	50	**172**	111
Interest, net		**87**	112	**257**	242
Foreign exchange (gain) loss	*(Note 5)*	**(25)**	156	**(560)**	(24)
Depreciation, depletion and amortization		**748**	605	**2,211**	1,392
		2,439	2,488	**7,447**	5,287
NET EARNINGS BEFORE THE UNDERNOTED		**677**	253	**2,931**	1,101
Income tax expense	*(Note 6)*	**278**	126	**513**	361
Distributions on Subsidiary Preferred Securities, net of tax		**–**	11	**–**	11
NET EARNINGS FROM CONTINUING OPERATIONS		**399**	116	**2,418**	729
NET EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 4)*	**1**	88	**294**	66
NET EARNINGS		**$ 400**	$ 204	**$ 2,712**	$ 795
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX		**7**	1	**(8)**	2
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS		**$ 393**	$ 203	**$ 2,720**	$ 793
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 9)*				
Basic		**$ 0.83**	$ 0.24	**$ 5.08**	$ 1.83
Diluted		**$ 0.82**	$ 0.24	**$ 5.00**	$ 1.80
NET EARNINGS PER COMMON SHARE	*(Note 9)*				
Basic		**$ 0.83**	$ 0.43	**$ 5.69**	$ 1.99
Diluted		**$ 0.82**	$ 0.42	**$ 5.60**	$ 1.96

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

		Nine Months Ended September 30	
($ millions)		**2003**	2002
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 4,684**	$ 3,630
Net Earnings		**2,712**	795
Dividends on Common Shares and Other Distributions, net of tax		**(135)**	(122)
Charges for Normal Course Issuer Bid	*(Note 8)*	**(503)**	–
RETAINED EARNINGS, END OF PERIOD		**$ 6,758**	$ 4,303

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED BALANCE SHEET *(unaudited)*

For the period ended September 30, 2003

($ millions)		As at September 30, 2003	As at December 31, 2002
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 335**	$ 183
Accounts receivable and accrued revenue		**1,295**	1,987
Inventories		**1,046**	528
Assets of discontinued operations	*(Note 4)*	**–**	3,422
		2,676	6,120
Capital Assets, net	*(Note 3)*	**24,440**	22,356
Investments and Other Assets		**627**	377
Goodwill		**2,469**	2,469
	(Note 3)	**$ 30,212**	$ 31,322
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,964**	$ 2,282
Income tax payable		**208**	20
Liabilities of discontinued operations	*(Note 4)*	**–**	1,758
Current portion of long-term debt	*(Note 7)*	**50**	212
		2,222	4,272
Long-Term Debt	*(Note 7)*	**7,103**	7,395
Deferred Credits and Other Liabilities		**557**	564
Future Income Taxes		**5,377**	4,840
Preferred Securities of Subsidiary		**–**	457
		15,259	17,528
Shareholders' Equity			
Preferred securities		**549**	126
Share capital	*(Note 8)*	**8,527**	8,732
Share options, net		**98**	133
Paid in surplus		**–**	61
Retained earnings		**6,758**	4,684
Foreign currency translation adjustment		**(979)**	58
		14,953	13,794
		$ 30,212	$ 31,322

See accompanying Notes to Consolidated Financial Statements.

EnCana Corporation

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

For the period ended September 30, 2003

		September 30			
		Three Months Ended		Nine Months Ended	
($ millions)		**2003**	2002	**2003**	2002
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 399**	$ 116	**$ 2,418**	$ 729
Depreciation, depletion and amortization		**748**	605	**2,211**	1,392
Future income taxes	*(Note 6)*	**203**	97	**475**	245
Other		**(3)**	98	**(467)**	(159)
Cash flow from continuing operations		**1,347**	916	**4,637**	2,207
Cash flow from discontinued operations		**5**	106	**5**	142
Cash flow		**1,352**	1,022	**4,642**	2,349
Net change in other assets and liabilities		**(92)**	–	**(115)**	(22)
Net change in non-cash working capital from continuing operations		**168**	(322)	**229**	(811)
Net change in non-cash working capital from discontinued operations		**(4)**	45	**78**	74
		1,424	745	**4,834**	1,590
INVESTING ACTIVITIES					
Business combination		**–**	–	**–**	(128)
Capital expenditures	*(Note 3)*	**(1,849)**	(1,440)	**(4,880)**	(3,311)
Proceeds on disposal of capital assets		**–**	133	**27**	376
Corporate acquisitions	*(Note 2)*	**(128)**	–	**(307)**	–
Equity investments		**(34)**	–	**(222)**	–
Net change in investments and other		**(56)**	27	**(96)**	15
Net change in non-cash working capital from continuing operations		**63**	83	**(173)**	(167)
Discontinued operations		**424**	(65)	**2,372**	(134)
		(1,580)	(1,262)	**(3,279)**	(3,349)
FINANCING ACTIVITIES					
Net issuance of long-term debt		**896**	813	**56**	1,305
Issuance of common shares	*(Note 8)*	**16**	27	**136**	96
Repurchase of common shares	*(Note 8)*	**(772)**	–	**(940)**	–
Dividends on common shares		**(47)**	(47)	**(143)**	(120)
Payments to preferred securities holders		**(20)**	(24)	**(32)**	(31)
Net change in non-cash working capital from continuing operations		**(5)**	3	**(13)**	2
Discontinued operations		**–**	(4)	**(438)**	(9)
Other		**11**	7	**(7)**	(25)
		79	775	**(1,381)**	1,218
DEDUCT: FOREIGN EXCHANGE (GAIN) LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**(6)**	(4)	**22**	7
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		**(71)**	262	**152**	(548)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**406**	153	**183**	963
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 335**	$ 415	**$ 335**	$ 415

See accompanying Notes to Consolidated Financial Statements.

NOTE 1 BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration, production and marketing of natural gas, natural gas liquids and crude oil, as well as natural gas storage operations, natural gas liquids processing and power generation operations.

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2002. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2002.

NOTE 2 CORPORATE ACQUISITIONS

On January 31, 2003, the Company acquired the Ecuadorian interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $179 million (US$116 million).

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $128 million (US$91 million). Savannah's operations are in Texas, USA.

These purchases were accounted for using the purchase method with the results reflected in the consolidated results of EnCana from the dates of acquisition. These acquisitions were accounted for as follows:

($ millions)	Vintage	Savannah
Working Capital	**$ 2**	**$ 1**
Capital Assets	**194**	**155**
Future Income Taxes	**(17)**	**(28)**
	$ 179	**$ 128**

NOTE 3 SEGMENTED INFORMATION

The Company has defined its continuing operations into the following segments:

- Upstream includes the Company's exploration for and production of natural gas, natural gas liquids and crude oil and related Non-Producing activities. The Company's Upstream operations are located in Canada, the United States, the U.K. central North Sea, Ecuador and International New Ventures exploration activity in the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia, Latin America, as well as the Canadian East Coast and the North American northern frontier.
- Midstream & Marketing includes natural gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry.

Operations that have been discontinued are disclosed in Note 4.

SEGMENTED INFORMATION (continued)

Results of Operations *(For the three months ended September 30)*

	Upstream		Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002
Revenues				
Gross revenue	**$ 2,410**	$ 1,828	**$ 1,077**	$ 1,165
Royalties and production taxes	**373**	256	**–**	–
Revenues, net of royalties and production taxes	**2,037**	1,572	**1,077**	1,165
Expenses				
Transportation and selling	**158**	126	**15**	48
Operating	**357**	296	**88**	54
Purchased product	**–**	–	**955**	1,041
Depreciation, depletion and amortization	**716**	579	**12**	10
Segment Income	**$ 806**	$ 571	**$ 7**	$ 12

	Corporate		Consolidated	
	2003	2002	**2003**	2002
Revenues				
Gross revenue	**$ 2**	$ 4	**$ 3,489**	$ 2,997
Royalties and production taxes	**–**	–	**373**	256
Revenues, net of royalties and production taxes	**2**	4	**3,116**	2,741
Expenses				
Transportation and selling	**–**	–	**173**	174
Operating	**–**	–	**445**	350
Purchased product	**–**	–	**955**	1,041
Depreciation, depletion and amortization	**20**	16	**748**	605
Segment Income	**$ (18)**	$ (12)	**795**	571
Administrative			**56**	50
Interest, net			**87**	112
Foreign exchange (gain) loss			**(25)**	156
			118	318
Net Earnings Before the Undernoted			**677**	253
Income tax expense			**278**	126
Distributions on subsidiary preferred securities, net of tax			**–**	11
Net Earnings from Continuing Operations			**$ 399**	$ 116

SEGMENTED INFORMATION (continued)

Geographic and Product Information *(For the three months ended September 30)*

UPSTREAM	North America					
	Produced Gas and NGLs					
	Canada		U.S. Rockies		Crude Oil	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 1,324**	$ 881	**$ 480**	$ 260	**$ 359**	$ 438
Royalties and production taxes	**180**	83	**130**	55	**21**	54
Revenues, net of royalties and production taxes	**1,144**	798	**350**	205	**338**	384
Expenses						
Transportation and selling	**99**	58	**30**	32	**12**	17
Operating	**128**	123	**26**	18	**113**	91
Depreciation, depletion and amortization	**377**	290	**107**	103	**167**	116
Segment Income	**$ 540**	$ 327	**$ 187**	$ 52	**$ 46**	$ 160

	Ecuador		U.K. North Sea		Non-Producing		Total Upstream	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 152**	$ 186	**$ 23**	$ 37	**$ 72**	$ 26	**$ 2,410**	$ 1,828
Royalties and production taxes	**42**	64	**–**	–	**–**	–	**373**	256
Revenues, net of royalties and production taxes	**110**	122	**23**	37	**72**	26	**2,037**	1,572
Expenses								
Transportation and selling	**12**	14	**5**	5	**–**	–	**158**	126
Operating	**22**	24	**4**	5	**64**	35	**357**	296
Depreciation, depletion and amortization	**46**	37	**16**	29	**3**	4	**716**	579
Segment Income	**$ 30**	$ 47	**$ (2)**	$ (2)	**$ 5**	$ (13)	**$ 806**	$ 571

MIDSTREAM & MARKETING	Midstream		Marketing*		Total Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 248**	$ 156	**$ 829**	$ 1,009	**$ 1,077**	$ 1,165
Expenses						
Transportation and selling	**–**	–	**15**	48	**15**	48
Operating	**79**	48	**9**	6	**88**	54
Purchased product	**155**	72	**800**	969	**955**	1,041
Depreciation, depletion and amortization	**10**	9	**2**	1	**12**	10
Segment Income	**$ 4**	$ 27	**$ 3**	$ (15)	**$ 7**	$ 12

* Includes transportation cost optimization activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

SEGMENTED INFORMATION (continued)

Results of Operations *(For the nine months ended September 30)*

	Upstream		Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002
Revenues				
Gross revenue	**$ 7,779**	$ 4,255	**$ 3,901**	$ 2,735
Royalties and production taxes	**1,306**	605	**–**	–
Revenues, net of royalties and production taxes	**6,473**	3,650	**3,901**	2,735
Expenses				
Transportation and selling	**474**	277	**63**	103
Operating	**1,026**	676	**346**	193
Purchased product	**–**	–	**3,458**	2,317
Depreciation, depletion and amortization	**2,136**	1,317	**30**	41
Segment Income	**$ 2,837**	$ 1,380	$ **4**	$ 81

	Corporate		Consolidated	
	2003	2002	**2003**	2002
Revenues				
Gross revenue	**$ 4**	$ 3	**$ 11,684**	$ 6,993
Royalties and production taxes	**–**	-	**1,306**	605
Revenues, net of royalties and production taxes	**4**	3	**10,378**	6,388
Expenses				
Transportation and selling	**–**	–	**537**	380
Operating	**–**	–	**1,372**	869
Purchased product	**–**	–	**3,458**	2,317
Depreciation, depletion and amortization	**45**	34	**2,211**	1,392
Segment Income	**$ (41)**	$ (31)	**2,800**	1,430
Administrative			**172**	111
Interest, net			**257**	242
Foreign exchange (gain)			**(560)**	(24)
			(131)	329
Net Earnings Before the Undernoted			**2,931**	1,101
Income tax expense			**513**	361
Distributions on subsidiary preferred securities, net of tax			**–**	11
Net Earnings from Continuing Operations			**$ 2,418**	$ 729

SEGMENTED INFORMATION (continued)

Geographic and Product Information *(For the nine months ended September 30)*

UPSTREAM	North America					
	Produced Gas and NGLs					
	Canada		U.S. Rockies		Crude Oil	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 4,377**	$ 2,193	**$ 1,491**	$ 467	**$ 1,150**	$ 1,040
Royalties and production taxes	**625**	243	**393**	104	**136**	135
Revenues, net of royalties and production taxes	**3,752**	1,950	**1,098**	363	**1,014**	905
Expenses						
Transportation and selling	**277**	146	**79**	57	**69**	35
Operating	**384**	274	**63**	38	**322**	227
Depreciation, depletion and amortization	**1,164**	697	**301**	195	**464**	279
Segment Income	**$ 1,927**	$ 833	**$ 655**	$ 73	**$ 159**	$ 364

	Ecuador		U.K. North Sea		Non-Producing		Total Upstream	
	2003	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues								
Gross revenue	**$ 475**	$ 368	**$ 105**	$ 126	**$ 181**	$ 61	**$ 7,779**	$ 4,255
Royalties and production taxes	**152**	123	**–**	–	**–**	–	**1,306**	605
Revenues, net of royalties and production taxes	**323**	245	**105**	126	**181**	61	**6,473**	3,650
Expenses								
Transportation and selling	**33**	24	**16**	15	**–**	–	**474**	277
Operating	**70**	55	**13**	11	**174**	71	**1,026**	676
Depreciation, depletion and amortization	**124**	88	**76**	48	**7**	10	**2,136**	1,317
Segment Income	**$ 96**	$ 78	**$ –**	$ 52	**$ –**	$ (20)	**$ 2,837**	$ 1,380

MIDSTREAM & MARKETING	Midstream		Marketing*		Total Midstream & Marketing	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002
Revenues						
Gross revenue	**$ 940**	$ 386	**$ 2,961**	$ 2,349	**$ 3,901**	$ 2,735
Expenses						
Transportation and selling	**–**	–	**63**	103	**63**	103
Operating	**272**	181	**74**	12	**346**	193
Purchased product	**613**	123	**2,845**	2,194	**3,458**	2,317
Depreciation, depletion and amortization	**27**	33	**3**	8	**30**	41
Segment Income	**$ 28**	$ 49	**$ (24)**	$ 32	**$ 4**	$ 81

* Includes transportation cost optimization activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

SEGMENTED INFORMATION (continued)

Capital Expenditures

($ millions)	Three Months Ended September 30 **2003**	2002	Nine Months Ended September 30 **2003**	2002
Upstream				
Canada	**$ 1,238**	$ 359	**$ 3,250**	$ 1,406
United States	**384**	876	**885**	1,500
Ecuador	**90**	96	**247**	168
United Kingdom	**26**	41	**64**	103
Other Countries	**21**	27	**89**	66
Midstream & Marketing	**80**	22	**290**	39
Corporate	**10**	19	**55**	29
Total	**$ 1,849**	$ 1,440	**$ 4,880**	$ 3,311

Capital and Total Assets

	Capital Assets		Total Assets	
	As at		As at	
($ millions)	**September 30, 2003**	December 31, 2002	**September 30, 2003**	December 31, 2002
Upstream	**$ 23,252**	$ 21,422	**$ 24,585**	$ 25,192
Midstream & Marketing	**970**	742	**2,469**	2,216
Corporate	**218**	192	**3,158**	492
Assets of Discontinued Operations			**–**	3,422
Total	**$ 24,440**	$ 22,356	**$ 30,212**	$ 31,322

NOTE 4 DISCONTINUED OPERATIONS

On February 28, 2003, the Company completed the sale of its 10 percent working interest in the Syncrude Joint Venture ("Syncrude") to Canadian Oil Sands Limited for net cash consideration of $1,026 million plus closing adjustments. The Company also granted Canadian Oil Sands Limited an option to purchase its remaining 3.75 percent working interest in Syncrude and a gross-overriding royalty interest. On July 10, 2003, the Company completed the sale of the remaining interest in Syncrude for net cash consideration of $427 million, subject to closing adjustments. This transaction completed the Company's disposition of its interest in Syncrude and, as a result, these operations have been accounted for as discontinued operations. There was no gain or loss on this sale.

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations. The wind-down of these operations was substantially completed at December 31, 2002.

On July 9, 2002, the Company announced that it planned to sell its 70 percent equity investment in the Cold Lake Pipeline System and its 100 percent interest in the Express Pipeline System. Accordingly, these operations have been accounted for as discontinued operations. On January 2, 2003 and January 9, 2003, the Company completed the sale of its interest in the Cold Lake Pipeline System and Express Pipeline System for total consideration of approximately $1.6 billion, including assumption of related long-term debt, and recorded an after-tax gain on sale of $263 million.

DISCONTINUED OPERATIONS (continued)

The following table presents the effect of the discontinued operations on the Consolidated Financial Statements:

Consolidated Statement of Earnings

	For the three months ended September 30							
	Syncrude		Merchant Energy		Midstream - Pipelines		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues, net of royalties and production taxes	**$ 11**	$ 141	**$ –**	$ 154	**$ –**	$ 91	**$ 11**	$ 386
Expenses								
Transportation and selling	**–**	2	**–**	–	**–**	–	**–**	2
Operating	**6**	44	**–**	–	**–**	33	**6**	77
Purchased product	**–**	–	**–**	162	**–**	–	**–**	162
Administrative	**–**	–	**–**	16	**–**	–	**–**	16
Interest, net	**–**	–	**–**	–	**–**	11	**–**	11
Foreign exchange loss	**–**	–	**–**	–	**–**	7	**–**	7
Depreciation, depletion and amortization	**1**	11	**–**	–	**–**	12	**1**	23
(Gain) loss on discontinuance	**–**	–	**–**	(29)	**–**	–	**–**	(29)
	7	57	**–**	149	**–**	63	**7**	269
Net Earnings Before Income Tax	**4**	84	**–**	5	**–**	28	**4**	117
Income tax expense	**3**	16	**–**	2	**–**	11	**3**	29
Net Earnings from Discontinued Operations	**$ 1**	$ 68	**$ –**	$ 3	**$ –**	$ 17	**$ 1**	$ 88

Consolidated Statement of Earnings

	For the nine months ended September 30							
	Syncrude*		Merchant Energy		Midstream - Pipelines*		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Revenues, net of royalties and production taxes	**$ 129**	$ 231	**$ –**	$ 1,463	**$ –**	$ 149	**$ 129**	$ 1,843
Expenses								
Transportation and selling	**2**	3	**–**	–	**–**	–	**2**	3
Operating	**69**	112	**–**	–	**–**	53	**69**	165
Purchased product	**–**	–	**–**	1,475	**–**	–	**–**	1,475
Administrative	**–**	–	**–**	34	**–**	–	**–**	34
Interest, net	**–**	–	**–**	–	**–**	22	**–**	22
Foreign exchange (gain)	**–**	–	**–**	–	**–**	(3)	**–**	(3)
Depreciation, depletion and amortization	**10**	18	**–**	1	**–**	23	**10**	42
(Gain) loss on discontinuance	**–**	–	**–**	24	**(343)**	–	**(343)**	24
	81	133	**–**	1,534	**(343)**	95	**(262)**	1,762
Net Earnings (Loss) Before Income Tax	**48**	98	**–**	(71)	**343**	54	**391**	81
Income tax expense (recovery)	**17**	18	**–**	(25)	**80**	22	**97**	15
Net Earnings (Loss) from Discontinued Operations	**$ 31**	$ 80	**$ –**	$ (46)	**$ 263**	$ 32	**$ 294**	$ 66

* Reflects only six months of earnings for 2002 as EnCana did not, at that time, own the operations which have been discontinued.

DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

	As at September 30							
	Syncrude		Merchant Energy		Midstream - Pipelines		Total	
($ millions)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Assets								
Cash and cash equivalents	**$ –**	$ 15	**$ –**	$ –	**$ –**	$ 60	**$ –**	$ 75
Accounts receivable and accrued revenue	**–**	54	**–**	55	**–**	32	**–**	141
Inventories	**–**	17	**–**	–	**–**	1	**–**	18
	–	86	**–**	55	**–**	93	**–**	234
Capital assets, net	**–**	1,332	**–**	–	**–**	819	**–**	2,151
Investments and other assets	**–**	–	**–**	–	**–**	369	**–**	369
Goodwill	**–**	417	**–**	–	**–**	–	**–**	417
	–	1,835	**–**	55	**–**	1,281	**–**	3,171
Liabilities								
Accounts payable and accrued liabilities	**–**	96	**–**	30	**–**	44	**–**	170
Income tax payable	**–**	(2)	**–**	–	**–**	5	**–**	3
Current portion of long-term debt	**–**	–	**–**	–	**–**	25	**–**	25
	–	94	**–**	30	**–**	74	**–**	198
Deferred credits and other liabilities	**–**	21	**–**	–	**–**	–	**–**	21
Long-term debt	**–**	–	**–**	–	**–**	583	**–**	583
Future income taxes	**–**	341	**–**	–	**–**	155	**–**	496
	–	456	**–**	30	**–**	812	**–**	1,298
Net Assets of Discontinued Operations	**$ –**	$ 1,379	**$ –**	$ 25	**$ –**	$ 469	**$ –**	$ 1,873

Consolidated Balance Sheet

	As at December 31	
($ millions)	2002	2001
Assets		
Cash and cash equivalents	$ 97	$ –
Accounts receivable and accrued revenue	96	632
Inventories	16	70
	209	702
Capital assets, net	2,231	9
Investments and other assets	374	17
Goodwill	608	–
	3,422	728
Liabilities		
Accounts payable and accrued liabilities	153	584
Income tax payable	11	–
Short-term debt	438	–
Current portion of long-term debt	23	–
	625	584
Long-term debt	576	–
Deferred credits and other liabilities	21	2
Future income taxes	536	–
	1,758	586
Net Assets of Discontinued Operations	$ 1,664	$ 142

NOTE 5 FOREIGN EXCHANGE (GAIN) LOSS

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2003**	2002	**2003**	2002
Unrealized foreign exchange (gain) loss on translation of U.S. dollar debt	**$ (18)**	$ 183	**$ (511)**	$ (21)
Other foreign exchange (gains)	**(7)**	(27)	**(49)**	(3)
	$ (25)	$ 156	**$ (560)**	$ (24)

NOTE 6 INCOME TAXES

	Three Months Ended September 30		Nine Months Ended September 30	
($ millions)	**2003**	2002	**2003**	2002
Provision for Income Taxes				
Current				
Canada	**$ 47**	$ 73	**$ (12)**	$ 137
United States	**14**	(57)	**14**	(49)
Ecuador	**11**	7	**30**	14
United Kingdom	**2**	4	**5**	12
Other Countries	**1**	2	**1**	2
	75	29	**38**	116
Future	**203**	97	**961**	287
Future tax rate reductions *	**–**	–	**(486)**	(42)
	$ 278	$ 126	**$ 513**	$ 361

* During the second quarter of 2003, both the Canadian federal and Alberta governments substantively enacted income tax rate reductions previously announced.

NOTE 7 LONG-TERM DEBT

($ millions)	**As at September 30, 2003**	As at December 31, 2002
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 1,624**	$ 1,388
Unsecured notes and debentures	**1,725**	1,825
	3,349	3,213
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**728**	696
Unsecured notes and debentures	**2,989**	3,608
	3,717	4,304
Increase in Value of Debt Acquired *	**87**	90
Current Portion of Long-Term Debt	**(50)**	(212)
	$ 7,103	$ 7,395

* Certain of the notes and debentures of the Company were acquired in the business combination with Alberta Energy Company Ltd. on April 5, 2002 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 23 years.

On October 2, 2003, the Company completed the issuance of US$500 million unsecured notes with a coupon rate of 4.75%. These notes mature in 2013. Proceeds from the offering were used to repay amounts recorded as revolving credit and term loan borrowings.

NOTE 8 SHARE CAPITAL

(millions)	September 30, 2003 Number	Amount	December 31, 2002 Number	Amount
Common Shares Outstanding, Beginning of Year	**478.9**	**$ 8,732**	254.9	$ 196
Shares Issued to AEC Shareholders	**–**	**–**	218.5	8,397
Shares Issued under Option Plans	**4.7**	**136**	5.5	139
Shares Repurchased	**(18.6)**	**(341)**	–	–
Common Shares Outstanding, End of Period	**465.0**	**$ 8,527**	478.9	$ 8,732

During the quarter, the Company purchased, for cancellation, 15,281,500 common shares (Year-to-date – 18,624,400 common shares) for total consideration of approximately $772 million (Year-to-date – $940 million). Of the $940 million paid this year, $341 million was charged to Share capital, $96 million was charged to Paid in surplus and $503 million was charged to Retained earnings.

The Company has stock-based compensation plans that allow employees and directors to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous successor and/or related company replacement plans expire ten years from the date the options were granted.

The following tables summarize the information about options to purchase common shares at September 30, 2003:

	Stock Options *(millions)*	**Weighted Average Exercise Price** *($)*
Outstanding, Beginning of Year	**29.6**	**39.74**
Granted under EnCana Plans	**6.1**	**47.98**
Exercised	**(4.7)**	**28.59**
Forfeited	**(1.1)**	**47.44**
Outstanding, End of Period	**29.9**	**42.89**
Exercisable, End of Period	**16.2**	**38.54**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *($)*
13.50 to 19.99	1.8	0.8	18.87	1.8	18.87
20.00 to 24.99	1.4	1.7	22.35	1.4	22.35
25.00 to 29.99	2.3	1.7	26.51	2.3	26.51
30.00 to 43.99	1.4	2.5	38.78	1.2	38.30
44.00 to 53.00	23.0	3.8	47.93	9.5	47.69
	29.9	2.8	42.89	16.2	38.54

SHARE CAPITAL (continued)

The Company does not record compensation expense in the Consolidated Financial Statements for share options granted to employees and directors. If the fair-value method had been used, the Company's Net Earnings and Net Earnings per Common Share would approximate the following pro forma amounts:

($ millions, except per share amounts)	Nine Months Ended September 30 **2003**	2002
Compensation Costs	**53**	65
Net Earnings		
As reported	**2,712**	795
Pro forma	**2,659**	730
Net Earnings per Common Share		
Basic		
As reported	**5.69**	1.99
Pro forma	**5.58**	1.83
Diluted		
As reported	**5.60**	1.96
Pro forma	**5.49**	1.80

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:

	Nine Months Ended September 30 **2003**	2002
Weighted Average Fair Value of Options Granted	**$ 12.21**	$ 13.35
Risk Free Interest Rate	**3.89%**	4.36%
Expected Lives (years)	**3.00**	3.00
Expected Volatility	**0.33**	0.35
Annual Dividend per Share	**$ 0.40**	$ 0.40

NOTE 9 PER SHARE AMOUNTS

The following table summarizes the common shares used in calculating net earnings per common share:

	Three Months Ended				Nine Months Ended	
	March 31	June 30	September 30		September 30	
(millions)	2003	2003	**2003**	2002	**2003**	2002
Weighted Average Common Shares Outstanding – Basic	479.9	480.6	**473.4**	476.8	**478.0**	397.8
Effect of Dilutive Securities	7.0	6.3	**7.1**	5.4	**8.3**	6.9
Weighted Average Common Shares Outstanding – Diluted	486.9	486.9	**480.5**	482.2	**486.3**	404.7

NOTE 10 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities are as follows:

($ millions)	**As at September 30, 2003**
Commodity Price Risk	
Crude oil	**$ (224)**
Gas storage optimization	**82**
Natural gas	**374**
Power	**4**
Foreign Currency Risk	**23**
Interest Rate Risk	**59**
Unrecognized Gains	**$ 318**

Information with respect to power, foreign currency risk and interest rate risk contracts in place at December 31, 2002, is disclosed in Note 19 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at September 30, 2003.

Crude Oil

As at September 30, 2003, the Company's corporate oil risk management activities had an unrecognized loss of $224 million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Unrecognized Gain/(Loss) *(C$ millions)*
Fixed WTI NYMEX Price	85,000	2003	25.28	$ (37)
Fixed WTI NYMEX Price	62,500	2004	23.13	(109)
Collars on WTI NYMEX	40,000	2003	21.95-29.00	(5)
Collars on WTI NYMEX	62,500	2004	20.00-25.69	(73)
				$ (224)

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial contracts at various locations and terms over the next 13 months to manage the price volatility of the corresponding physical transactions and inventory.

As at September 30, 2003, the unrecognized gain on gas storage optimization contracts was $82 million. The contracts are as follows:

	Notional Volumes *(bcf)*	Price *(US$/mcf)*	Unrecognized Gain/(Loss) *(C$ millions)*
Financial Instruments			
Purchases	213.1	5.21	$ (77)
Sales	251.4	5.44	125
			48
Physical Contracts			34
			$ 82

The unrecognized gain does not reflect unrealized gains on physical inventory in storage.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At September 30, 2003, the fair value of financial instruments and physical contracts that related to the corporate gas risk management activities was $374 million. The contracts are as follows:

	Notional Volumes *(MMcf/d)*	Physical/ Financial	Term	Price		Unrecognized Gain/(Loss) *(C$ millions)*
Fixed Price Contracts						
Sales Contracts						
Fixed AECO price	561	Financial	2003	6.36	C$/mcf	$ 27
Fixed AECO price	10	Financial	2003	3.37	US$/mmbtu	(1)
Fixed AECO price	10	Physical	2003	3.34	US$/mmbtu	(1)
NYMEX Fixed price*	536	Financial	2003	4.50	US$/mmbtu	(19)
NYMEX Collars	50	Physical	2003	2.46-4.90	US$/mmbtu	(1)
Fixed AECO price	453	Financial	2004	6.20	C$/mcf	77
AECO Collars	71	Financial	2004	5.34-7.52	C$/mcf	8
NYMEX Fixed price*	536	Financial	2004	5.06	US$/mmbtu	48
Chicago Fixed price	40	Financial	2004	5.42	US$/mmbtu	9
NYMEX Collars	10	Financial	2004	4.60-6.55	US$/mmbtu	2
NYMEX Collars	50	Physical	2004	2.46-4.90	US$/mmbtu	(16)
NYMEX Collars	47	Physical	2005-2007	2.46-4.90	US$/mmbtu	(40)
Basis Contracts						
Sales Contracts						
Fixed NYMEX to AECO basis*	364	Financial	2003	(0.55)	US$/mmbtu	(2)
Fixed NYMEX to Rockies basis	280	Financial	2003	(0.50)	US$/mmbtu	(2)
Fixed NYMEX to Rockies basis	418	Physical	2003	(0.52)	US$/mmbtu	(5)
Fixed NYMEX to San Juan basis	33	Financial	2003	(0.63)	US$/mmbtu	(1)
Fixed NYMEX to San Juan basis	33	Physical	2003	(0.64)	US$/mmbtu	(1)
Fixed NYMEX to AECO basis*	336	Financial	2004	(0.54)	US$/mmbtu	24
Fixed NYMEX to Rockies basis	190	Financial	2004	(0.42)	US$/mmbtu	16
Fixed NYMEX to Rockies basis	403	Physical	2004	(0.49)	US$/mmbtu	20
Fixed NYMEX to San Juan basis	60	Financial	2004	(0.63)	US$/mmbtu	(1)
Fixed NYMEX to San Juan basis	50	Physical	2004	(0.64)	US$/mmbtu	(1)
Fixed NYMEX to AECO basis*	677	Financial	2005-2007	(0.65)	US$/mmbtu	69
Fixed NYMEX to Rockies basis	132	Financial	2005-2007	(0.44)	US$/mmbtu	49
Fixed NYMEX to Rockies basis	250	Physical	2005-2007	(0.47)	US$/mmbtu	83
Fixed NYMEX to San Juan basis	69	Financial	2005-2006	(0.63)	US$/mmbtu	–
Fixed NYMEX to San Juan basis	46	Physical	2005-2006	(0.64)	US$/mmbtu	(1)
Purchase Contracts						
Fixed Nymex to AECO basis*	119	Financial	2003	(0.77)	US$/mmbtu	2
Alliance Pipeline Mitigation						
Sale Contracts	14	Financial	2003	3.92	US$/mmbtu	(1)
Purchase Contracts	15	Physical	2003	3.24	C$/mcf	3
						344
Gas Marketing Financial Positions [(1)]						(3)
Gas Marketing Physical Positions [(1)]						33
						$ 374

* Certain Fixed NYMEX to AECO basis and NYMEX Fixed price contracts have previously been combined and reported as Fixed AECO prices. They are now reclassified and reported separately.

[(1)] The gas marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

NOTE 11 RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2003.

Financial Statistics

(C$ millions, except per share amounts)	2003				2002		
	Year-to-date	**Q3**	Q2	Q1	Q4	Q3	Q2
Cash Flow	**4,642**	**1,352**	1,438	1,852	1,472	1,022	938
Per share – Basic	**9.71**	**2.86**	2.99	3.86	3.08	2.14	2.03
– Diluted	**9.55**	**2.81**	2.95	3.80	3.03	2.12	2.00
Net Earnings	**2,712**	**400**	1,066	1,246	429	204	458
Per share – Basic	**5.69**	**0.83**	2.24	2.61	0.90	0.43	0.99
– Diluted	**5.60**	**0.82**	2.21	2.57	0.88	0.42	0.97
Net Earnings from Continuing Operations	**2,418**	**399**	1,063	956	374	116	482
Per share – Basic	**5.08**	**0.83**	2.23	2.00	0.78	0.24	1.04
– Diluted	**5.00**	**0.82**	2.20	1.98	0.77	0.24	1.02
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) *	**2,012**	**385**	864	763	364	261	319
Per share – Diluted	**4.17**	**0.79**	1.79	1.58	0.75	0.54	0.67
Earnings from Continuing Operations, excluding foreign exchange translation of U.S. dollar debt (after tax) and tax rate change gain	**1,526**	**385**	378	763	364	261	277
Per share – Diluted	**3.17**	**0.79**	0.79	1.58	0.75	0.54	0.58

Shares	2003				2002		
	Year-to-date	**Q3**	Q2	Q1	Q4	Q3	Q2
Common Shares Outstanding *(millions)*							
Period end	**465.0**	**465.0**	479.9	480.6	478.9	477.4	476.3
Average – Basic	**478.0**	**473.4**	480.6	479.9	477.9	476.8	461.1
Average – Diluted	**486.3**	**480.5**	486.9	486.9	485.2	482.2	470.0
Closing Price Range *($ per share)*							
TSX – C$							
High	**53.09**	**52.43**	53.09	49.55	49.75	48.25	50.25
Low	**45.70**	**47.55**	45.70	46.06	41.75	38.05	43.62
Close	**48.90**	**48.90**	51.70	47.75	48.78	48.00	46.70
NYSE – US$							
High	**39.26**	**38.14**	39.26	33.39	32.10	31.35	32.20
Low	**29.92**	**34.36**	31.04	29.92	26.45	24.08	28.50
Close	**36.38**	**36.38**	38.37	32.36	31.10	30.10	30.60
Share Volume Traded *(millions)*	**335.2**	**117.9**	107.2	110.2	122.3	105.5	113.2
Share Value Traded *($ millions weekly average)*	**417.2**	**443.4**	405.4	402.9	418.3	366.3	412.6

Ratios	
Debt to Capitalization	**33%**
Return on Capital Employed	**16%**
Return on Common Equity	**23%**

* The Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustments recorded in the Consolidated Statement of Earnings.

Financial Statistics *(continued)*

Net Capital Investment *(C$ millions)*	**2003**	Pro Forma 2002
Upstream		
Canada	**$ 2,988**	$ 1,818
United States	**868**	748
Ecuador	**247**	236
United Kingdom	**64**	103
Other Countries	**89**	59
	4,256	2,964
Midstream & Marketing	**290**	46
Corporate	**55**	33
Core Capital	**4,601**	3,043
Acquisitions		
Property (mainly leased equipment buyouts in 2003)	**279**	1,041
Corporate	**307**	–
Dispositions		
Upstream	**(27)**	(419)
Midstream & Marketing	**–**	(1)
Net Capital Investment – Continuing Operations	**5,160**	3,664
Discontinued Operations	**(2,372)**	173
Total Net Capital Investment	**$ 2,788**	$ 3,837

EnCana Corporation

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

For the period ended September 30, 2003

Pro Forma Operating Statistics

Sales Volumes	**2003**				2002			
	Year-to-date	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1*
Produced Gas *(MMcf/d)*								
Canada								
Production	**2,199**	**2,197**	2,213	2,190	2,226	2,209	2,262	2,188
Inventory withdrawal/(injection)	**47**	**–**	–	141	149	(80)	(118)	160
Canada Sales	**2,246**	**2,197**	2,213	2,331	2,375	2,129	2,144	2,348
United States	**709**	**757**	698	672	654	550	428	365
United Kingdom	**11**	**7**	12	13	8	9	8	11
	2,966	**2,961**	2,923	3,016	3,037	2,688	2,580	2,724
Oil and Natural Gas Liquids *(bbls/d)*								
North America								
Light and Medium Oil	**59,653**	**59,708**	59,012	60,246	62,369	65,345	66,807	70,914
Heavy Oil	**95,811**	**104,702**	91,939	90,636	86,019	80,797	76,233	68,846
Natural Gas Liquids								
Canada	**17,863**	**16,488**	17,970	19,162	19,121	16,225	16,796	17,448
United States	**11,196**	**11,487**	12,329	9,751	11,558	6,702	7,115	6,427
Total North America	**184,523**	**192,385**	181,250	179,795	179,067	169,069	166,951	163,635
Ecuador								
Production	**59,234**	**73,760**	49,006	54,726	48,486	52,344	52,744	50,351
Transferred to OCP Pipeline**	**(5,932)**	**(6,805)**	(2,816)	(8,191)	–	–	–	–
Over/(under) lifting	**(4,635)**	**(13,412)**	3,385	(3,771)	1,448	3,235	7,120	(11,577)
Ecuador Sales	**48,667**	**53,543**	49,575	42,764	49,934	55,579	59,864	38,774
United Kingdom	**8,463**	**5,813**	9,019	10,610	7,786	9,538	11,966	12,889
Total Oil and Natural Gas Liquids	**241,653**	**251,741**	239,844	233,169	236,787	234,186	238,781	215,298
Total *(boe/d)*	**735,986**	**745,241**	727,011	735,836	742,954	682,186	668,781	669,298
Syncrude	**10,291**	**3,401**	7,383	20,272	34,261	36,039	24,295	31,548

* Q1 2002 volumes have been presented on a pro forma basis.

** Crude oil production in Ecuador transferred to the OCP Pipeline for use by OCP in asset commissioning.

Operating Statistics

Per-unit Results	**2003**				2002		
	Year-to-date	**Q3**	Q2	Q1	Q4	Q3	Q2
Produced Gas – Canada (C*$/Mcf)*							
Price, net of transportation and selling	**6.71**	**5.80**	6.43	7.85	5.17	3.24	4.23
Royalties	**0.97**	**0.85**	1.05	1.00	0.77	0.39	0.65
Operating expenses	**0.59**	**0.58**	0.54	0.63	0.59	0.58	0.54
Netback excluding hedge	**5.15**	**4.37**	4.84	6.22	3.81	2.27	3.04
Financial Hedge	**(0.34)**	**(0.04)**	(0.31)	(0.65)	(0.08)	0.29	(0.12)
Netback including hedge	**4.81**	**4.33**	4.53	5.57	3.73	2.56	2.92
Produced Gas – United States *(C$/Mcf)*							
Price, net of transportation and selling	**6.57**	**6.11**	6.13	7.55	4.74	3.16	3.56
Royalties	**1.89**	**1.73**	1.74	2.23	1.42	0.99	0.98
Operating expenses	**0.31**	**0.36**	0.33	0.25	0.28	0.34	0.38
Netback excluding hedge	**4.37**	**4.02**	4.06	5.07	3.04	1.83	2.20
Financial Hedge	**0.11**	**(0.17)**	(0.24)	0.80	0.42	0.57	0.06
Netback including hedge	**4.48**	**3.85**	3.82	5.87	3.46	2.40	2.26
Produced Gas – Total *(C$/Mcf)*							
Price, net of transportation and selling	**6.68**	**5.88**	6.36	7.78	5.08	3.21	4.11
Royalties	1.**19**	**1.08**	1.22	1.28	0.91	0.51	0.70
Operating expenses	**0.52**	**0.53**	0.49	0.54	0.52	0.53	0.52
Netback excluding hedge	**4.97**	**4.27**	4.65	5.96	3.65	2.17	2.89
Financial Hedge	**(0.23)**	**(0.07)**	(0.30)	(0.33)	0.03	0.35	(0.09)
Netback including hedge	**4.74**	**4.20**	4.35	5.63	3.68	2.52	2.80

Operating Statistics

Per-unit Results (continued)	**2003**				2002		
	Year-to-date	**Q3**	Q2	Q1	Q4	Q3	Q2
Light and Medium Oil – North America *(C$/bbl)*							
Price, net of transportation and selling	**36.56**	**32.59**	35.81	41.36	36.36	36.01	35.35
Royalties *	**4.61**	**3.68**	4.33	5.82	4.81	4.56	4.36
Operating expenses	**7.75**	**8.02**	7.54	7.68	7.16	6.58	7.25
Netback excluding hedge	**24.20**	**20.89**	23.94	27.86	24.39	24.87	23.74
Financial Hedge	**(5.48)**	**(4.08)**	(3.59)	(8.83)	(1.26)	(0.89)	(1.59)
Netback including hedge	**18.72**	**16.81**	20.35	19.03	23.13	23.98	22.15
Heavy Oil – North America *(C$/bbl)*							
Price, net of transportation and selling	**27.05**	**23.96**	25.94	31.80	25.81	29.44	26.85
Royalties *	**3.17**	**2.40**	3.25	3.99	3.43	3.67	3.09
Operating expenses	**7.47**	**7.38**	7.52	7.52	5.64	6.71	5.87
Netback excluding hedge	**16.41**	**14.18**	15.17	20.29	16.74	19.06	17.89
Financial Hedge	**(5.11)**	**(3.95)**	(2.74)	(8.83)	(1.18)	(0.89)	(0.76)
Netback including hedge	**11.30**	**10.23**	12.43	11.46	15.56	18.17	17.13
Total Oil – North America *(C$/bbl)*							
Price, net of transportation and selling	**30.70**	**27.09**	29.80	35.61	30.26	32.38	30.82
Royalties *	**3.72**	**2.87**	3.67	4.72	4.01	4.07	3.68
Operating expenses	**7.58**	**7.61**	7.53	7.59	6.28	6.66	6.51
Netback excluding hedge	**19.40**	**16.61**	18.60	23.30	19.97	21.65	20.63
Financial Hedge	**(5.25)**	**(4.00)**	(3.08)	(8.83)	(1.22)	(0.89)	(1.15)
Netback including hedge	**14.15**	**12.61**	15.52	14.47	18.75	20.76	19.48
Natural Gas Liquids – Canada *(C$/bbl)*							
Price, net of transportation and selling	**34.29**	**31.65**	29.40	41.25	34.15	27.51	27.07
Royalties	**6.35**	**5.24**	5.28	8.33	5.60	3.80	4.24
Netback	**27.94**	**26.41**	24.12	32.92	28.55	23.71	22.83
Natural Gas Liquids – United States *(C$/bbl)*							
Price, net of transportation and selling	**38.77**	**35.18**	34.45	48.59	39.47	40.07	36.65
Royalties	**8.96**	**9.02**	7.37	10.92	6.54	6.60	5.75
Netback	**29.81**	**26.16**	27.08	37.67	32.93	33.47	30.90
Natural Gas Liquids – Total *(C$/bbl)*							
Price, net of transportation and selling	**36.01**	**33.10**	31.45	43.73	36.15	31.18	29.92
Royalties	**7.35**	**6.79**	6.13	9.21	5.95	4.62	4.69
Netback	**28.66**	**26.31**	25.32	34.52	30.20	26.56	25.23
Ecuador Oil *(C$/bbl)*							
Price, net of transportation and selling	**33.27**	**28.40**	29.50	43.90	35.38	33.59	31.67
Royalties	**11.47**	**8.59**	9.78	17.12	12.29	12.51	10.76
Operating expenses	**5.28**	**4.45**	5.91	5.63	6.04	4.60	5.70
Netback excluding hedge	**16.52**	**15.36**	13.81	21.15	17.05	16.48	15.21
Financial Hedge	**–**	**–**	–	–	–	–	(0.04)
Netback including hedge	**16.52**	**15.36**	13.81	21.15	17.05	16.48	15.17
United Kingdom Oil *(C$/bbl)*							
Price, net of transportation and selling	**38.37**	**35.79**	35.58	42.53	37.99	39.30	37.78
Operating expenses	**6.27**	**9.03**	6.56	4.41	11.10	5.71	3.12
Netback	**32.10**	**26.76**	29.02	38.12	26.89	33.59	34.66

* Excludes impact of amendments, made in Q3 2003, related to prior years which reduced royalties by $21 million.

CONVENIENCE STATEMENTS

(Prepared in US$) For the period ended September 30, 2003

The Consolidated Financial Statements of the Company are prepared in Canadian dollars. The financial information presented below shows the Canadian GAAP financial information and has been translated into U.S. dollars for the convenience of the readers. The financial information presented below has been translated into U.S. dollars at a rate of $1 Canadian equals US$0.74, the rate of exchange on September 30, 2003. This translation should not be construed as a representation that the Canadian dollar amounts shown in the Consolidated Financial Statements could be converted into U.S. dollars at the rate of $1 Canadian equals US$0.74 or at any other rate.

Consolidated Statement of Earnings *(unaudited)*

(US$ millions, except per share amounts)	**Nine months ended September 30 2003**
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	**$ 7,680**
EXPENSES	
Transportation and selling	**398**
Operating	**1,015**
Purchased product	**2,559**
Administrative	**127**
Interest, net	**190**
Foreign exchange (gain)	**(414)**
Depreciation, depletion and amortization	**1,636**
	5,511
EARNINGS BEFORE THE UNDERNOTED	**2,169**
Income tax expense	**380**
NET EARNINGS FROM CONTINUING OPERATIONS	**1,789**
NET EARNINGS FROM DISCONTINUED OPERATIONS	**218**
NET EARNINGS	**2,007**
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX	**(6)**
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$ 2,013**
NET EARNINGS PER COMMON SHARE – DILUTED	**$ 4.14**

Condensed Consolidated Balance Sheet *(unaudited)*

(US$ millions)	**As at September 30 2003**
ASSETS	
Current Assets	**$ 1,980**
Capital Assets, net	**18,086**
Investments and Other Assets	**464**
Goodwill	**1,827**
	$ 22,357
LIABILITIES AND SHAREHOLDERS' EQUITY	
Current Liabilities	**$ 1,644**
Long-Term Debt	**5,257**
Deferred Credits and Other Liabilities	**412**
Future Income Taxes	**3,979**
	11,292
Shareholders' Equity	**11,065**
	$ 22,357

EnCana Corporation

CONVENIENCE STATEMENTS

(Prepared in US$) For the period ended September 30, 2003

Condensed Consolidated Statement of Cash Flows *(unaudited)*

(US$ millions, except per share amounts)	**Nine months ended September 30 2003**
CASH FROM OPERATING ACTIVITIES	
Net earnings from continuing operations	**$ 1,789**
Depreciation, depletion and amortization	**1,636**
Future income taxes	**352**
Other	**(346)**
Cash flow from continuing operations	**3,431**
Cash flow from discontinuing operations	**4**
Cash flow	**3,435**
Net change in other assets and liabilities	**(85)**
Net change in non-cash working capital from continuing operations	**169**
Net change in non-cash working capital from discontinued operations	**58**
	$ 3,577
CASH USED IN INVESTING ACTIVITIES	**$ (2,426)**
CASH USED IN FINANCING ACTIVITIES	**$ (1,022)**
CASH FLOW PER COMMON SHARE – DILUTED	**$ 7.06**

ENCANA CORPORATION

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