Third quarter report
for the period ended
September 30, 2005

Q3

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EnCana

energy for people

EnCana's third quarter cash flow reaches US$1.93 billion, or $2.20 per share – up 51 percent

Natural gas sales increase 3 percent to 3.2 billion cubic feet per day

Calgary, Alberta, (October 26, 2005) – EnCana Corporation's (TSX & NYSE: ECA) third quarter 2005 total cash flow per share increased 51 percent to US$2.20 per share diluted, or $1.93 billion, compared to the third quarter of 2004. Total operating earnings per share increased 33 percent to 80 cents per share diluted, or $704 million, compared to the third quarter of 2004. Cash flow and operating earnings increased due to stronger natural gas and liquids prices and increased gas sales.

EnCana's third quarter net earnings were 30 cents per share diluted, or $266 million, which included an unrealized after-tax loss of $604 million due to mark-to-market accounting of all hedges and an unrealized foreign exchange after-tax gain of $166 million on translation of Canadian issued U.S. dollar debt. Of the $604 million unrealized hedging loss, about 60 percent relates to EnCana's 2004 acquisition of Tom Brown, Inc. All of the Tom Brown hedge positions expire at the end of 2006. In 2006, 82 percent of EnCana's forecast sales are fully exposed to price upside. Total third quarter revenues net of royalties were $3.38 billion.

IMPORTANT NOTE: EnCana reports in U.S. dollars and follows U.S. protocols, which report sales and reserves on an after-royalties basis. All dollar figures are U.S. dollars unless otherwise noted. All prior-period share and per-share references have been adjusted to reflect the two-for-one common share split which occurred in May 2005. EnCana is treating its Ecuador operations as discontinued because EnCana is in the process of selling its Ecuador assets. Total results, which include results from Ecuador, are reported in the company's financial statements included in this news release and in supplementary documents posted on its website – www.encana.com.

On September 13, 2005, EnCana announced it had reached an agreement to sell all of its interests in Ecuador for approximately $1.42 billion, which is approximately equivalent to the net book value of the assets at July 1, 2005, the effective date of the transaction. In accordance with Generally Accepted Accounting Principles for discontinued operations, the carrying value of EnCana's investments in Ecuador cannot exceed the expected selling price; therefore, no net earnings from these assets will be shown subsequent to July 1, 2005.

Total natural gas sales in the third quarter increased to 3.22 billion cubic feet per day, up 3 percent compared to the third quarter of 2004. Oil and natural gas liquids (NGLs) sales were 219,200 barrels per day, down 16 percent mainly due to divestitures of conventional oil properties in Canada and the U.K. North Sea and lower Ecuador sales. Third quarter sales of natural gas, oil and NGLs from total operations were 4.5 billion cubic feet of gas equivalent (Bcfe) per day. The impact of divestitures and a delay in the timing of production additions resulted in total sales being down 3 percent from the third quarter of 2004.

Third quarter generates strong cash flow, key resource play production up 13 percent

"Our third quarter was marked by strong cash flow and operating earnings, plus steady growth from continuing operations in North American natural gas production – up 4 percent, or 126 million cubic feet per day, since the third quarter of 2004. Record setting wet weather in key Western Canadian producing regions and industry activity levels in the North American oil and gas service sector have restricted access to land and equipment in an unprecedented way this year. As a result, we have drilled fewer wells to date this year than planned and our gas production volumes are lagging forecast rates. EnCana also has wells capable of delivering about 225 million cubic feet per day of natural gas production waiting to be tied in to gathering and sales pipelines. With more than 120 operated rigs active in our gas fields, we are expecting to exit 2005 with gas sales of about 3.4 billion to 3.5 billion cubic feet per day," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

"The difference between our reduced 2005 production outlook and the midpoint of our original guidance range amounts to about a two-month delay in the ramp up of gas production. Our 2005 average gas production is now forecast to be in the range of 3.25 billion to 3.30 billion cubic feet per day, slightly below our original guidance range, but about 9 percent higher than average 2004 sales. North American oil and NGLs sales are forecast to be within original guidance. Despite these challenges, production from our key resource plays is up 13 percent in the past year. The reservoir performance across our portfolio of long-life unconventional assets remains strong. At the same time, EnCana shareholders are benefiting from the market's robust energy prices and our projects continue to generate strong investment returns," Morgan said.

2006 gas sales forecast to rise between 7 and 11 percent

In 2006, EnCana is forecasting gas sales of between 3.50 billion and 3.63 billion cubic feet per day, which represents an increase of between 7 and 11 percent from forecast midpoint for 2005 sales. North American oil and NGLs sales are expected to be about the same as 2004, in the range of 155,000 to 160,000 barrels of oil per day, which reflects growth from expanding oilsands projects being offset by declining production in conventional oil properties and higher royalty rates due to achieving payout status at Pelican Lake around year-end. Total North American sales are forecast to be between 4.43 billion and 4.59 billion cubic feet equivalent per day, an increase of between 5 and 9 percent from the midpoint of the updated total North American sales guidance range for 2005.

Moderated growth in 2006 expected to generate free cash flow

"We expect that 2006 will be characterized by continued high industry activity levels and inflationary pressures, which are the product of the strong commodity prices that are generating robust netbacks. Given these conditions and the learnings we've gained from this year's experience, we have moderated our North American production growth rate to between 5 and 9 percent – a measured pace that's aimed at more efficiently converting our proved reserves into sales growth and our Unbooked Resource Potential into proved reserves as we generate substantial free cash flow," said Randy Eresman, EnCana's Chief Operating Officer.

Third quarter milestones: Ecuador sale deal reached, Entrega pipeline under construction, Brazil discovery

EnCana reached a series of important milestones in the third quarter: an agreement to sell its Ecuador assets for $1.42 billion and the start of construction on the Entrega natural gas pipeline out of the Piceance Basin in the U.S. Rockies. In the waters offshore Brazil, EnCana drilled and tested a third appraisal well about four kilometres from a promising oil discovery named Chinook located in block BM-C-7. The test well was recently followed up by an additional successful appraisal well that also encountered oil and high-quality reservoir sands. Advancing the company's oilsands market integration initiative, the company has arranged to import diluent from overseas markets. In Texas, EnCana has made an initial land purchase in the Maverick Basin – about 330,000 net acres with multi-zone gas resource play potential.

Cutbank Doig formation gas discovery underlies Cutbank Ridge resource play

"In addition, we recently made a substantial natural gas discovery in British Columbia below our Cutbank Ridge resource play. This Cutbank Doig find, which we estimate contains 350 billion to 550 billion cubic feet of original gas in place net to EnCana, is producing about 25 million cubic feet of gas per day in October from five wells. It is believed to be similar in characteristics to the nearby Sinclair Doig pool in Alberta, which was discovered in the late 1970s by an EnCana predecessor company, has produced more than 250 billion cubic feet to date and is expected to yield more than 400 billion cubic feet during its life. Cutbank Doig is a clear illustration of the exploration upside potential of deeper formations underlying the extensive lands of our key resource plays.

"Alongside our continued strong resource play performance, all of these third quarter achievements help reinforce EnCana's foundation for expected sustainable profitable sales growth in future years," Eresman said.

Oilsands resources capable of delivering large, long-term production expansion
"Our in-situ oilsands developments in northeast Alberta continue to achieve top-level capital and operating efficiency. Expansion of Foster Creek from 30,000 to 60,000 barrels per day is proceeding on schedule and should be fully on stream by the end of 2006. Beyond that, we plan to progressively develop steam-assisted gravity drainage production to more than 200,000 barrels of oil per day generally with projects and expansions of approximately 30,000 barrel per day increments. This is a size where we believe we have the opportunity to capture advantages of scale while maintaining control of execution, schedules and costs," Eresman said.

Nine months cash flow per share up 47 percent
Total cash flow per share in the first nine months increased 47 percent to $5.50 per share diluted, or $4.92 billion. Total nine months operating earnings increased 47 percent to $2.20 per share diluted, or $1.97 billion. EnCana's total nine months net earnings per share increased 19 percent to $1.19 per share diluted, or $1.06 billion, which includes an unrealized mark-to-market after-tax loss of $1,023 million due to changes in the value of commodity hedging positions at September 30, 2005 and an unrealized foreign exchange gain of $113 million on translation of Canadian issued U.S. dollar debt.

Nine months sales of natural gas, oil and NGLs from total operations were 4.55 Bcfe per day, about the same as in the first nine months of 2004. Total natural gas sales increased 8 percent to 3.19 billion cubic feet per day. Total oil and NGLs sales were 226,300 barrels per day, down 14 percent mainly due to divestitures of conventional oil properties in Canada and the U.K. North Sea.

IMPORTANT NOTE: All references in the remaining text of this news release are on a continuing operations basis, which does not include results of the Ecuador business, as it has been accounted for as discontinued.

Continuing operations: Cash flow up 45 percent; Operating earnings up 32 percent
Third quarter 2005 cash flow from continuing operations increased 45 percent to $1.82 billion compared to the same period in 2004. Cash taxes during the third quarter were $169 million. Operating earnings from continuing operations increased 32 percent to $731 million compared to the third quarter of 2004. EnCana's third quarter net earnings from continuing operations decreased 38 percent to $266 million, which included a $631 million after-tax unrealized mark-to-market loss as a result of changes in the value of commodity hedging positions at quarter-end compared to the previous quarter and an after-tax unrealized gain of $166 million due to translation of U.S. dollar denominated debt issued in Canada.

Natural gas sales from continuing operations up 4 percent, total sales steady
Third quarter natural gas sales from continuing operations rose 4 percent to 3.22 billion cubic feet per day compared with the third quarter of 2004, mainly from resource play growth. Oil and NGLs sales from continuing operations were 150,500 barrels per day, down 11 percent from the third quarter one year earlier, due to property divestitures. Third quarter sales of natural gas, oil and NGLs from continuing operations were 4.13 Bcfe per day, about the same as during the third quarter of 2004.

Operating costs impacted by inflation and a depreciating U.S. dollar
Operating costs from continuing operations in the third quarter of 2005 were 69 cents per thousand cubic feet of gas equivalent (Mcfe), which is higher than the company's previous forecast range due mainly to industry inflation, the impact of a depreciating U.S. dollar, increased long-term, stock-based compensation expenses and weather delays of planned production additions. June was the wettest month in recorded history in Alberta and with the oil and gas service sector running at unprecedented levels, the company has found that it is unable to make up for lost drilling and completion days as it has done in the past. To help mitigate these challenges, EnCana is contracting with drilling companies to build an additional 46 fit-for-purpose rigs. While EnCana expects full year operating costs to

be about 13 percent higher than the company's previous forecast of 55 to 60 cents per Mcfe, EnCana expects to continue to be amongst the lowest cost operators in the industry. EnCana drilled 1,150 net wells during the third quarter. Third quarter core capital investment was $1.46 billion. The company's recent addition of approximately $250 million of capital investment in 2005 is directed to capture key land positions in emerging resource plays. EnCana has updated its 2005 corporate guidance to reflect its most recent sales and operating cost outlooks, and has posted its 2006 corporate guidance on its website, www.encana.com.

Nine months operating earnings from continuing operations up 36 percent

Nine months 2005 operating earnings increased 36 percent to $1.87 billion. Nine months 2005 cash flow from continuing operations increased 46 percent to $4.64 billion. EnCana's nine months net earnings from continuing operations decreased 9 percent to $927 million, which includes two non-cash items: an after-tax unrealized mark-to-market hedge loss of $1.06 billion and an after-tax unrealized mark-to-market gain on foreign exchange on U.S. dollar denominated debt issued in Canada of $113 million. Nine months 2005 revenues net of royalties were $9.33 billion. EnCana drilled 3,520 net wells in the first nine months of 2005.

North American natural gas prices strengthen in the third quarter of 2005

The average third quarter benchmark NYMEX index gas price was $8.49 per thousand cubic feet, up 47 percent from $5.76 per thousand cubic feet in the third quarter of 2004. EnCana's North American realized natural gas prices, excluding financial hedging, averaged $7.29 per thousand cubic feet, up 41 percent from an average of $5.18 per thousand cubic feet in the third quarter of 2004. Natural gas prices have continued to increase due primarily to high world oil prices, continued global economic strength, a lack of growth in domestic natural gas production and hurricane damage to Gulf of Mexico production facilities.

Third quarter world oil and Canadian heavy oil prices remain strong

Oil and NGLs continued to trade at strong prices during the third quarter of 2005 due to continued global demand growth, diminished supply due to Gulf of Mexico hurricane damage and tightening global production and refining capacity. During the third quarter of 2005, the average benchmark West Texas Intermediate (WTI) crude oil price was $63.31 per barrel, up 44 percent from the third quarter 2004 average of $43.89 per barrel. Strong asphalt markets in Canada in the third quarter helped support Canadian heavy oil prices. The WTI/Bow River differential was $17.08 per barrel, yielding a Bow River blend price of $46.23 per barrel, a price that was about 73 percent of WTI prices, which is about the same in percentage terms as in the third quarter of 2004. In the third quarter, EnCana's average realized oil and NGLs price was $46.16 per barrel, up 44 percent from the third quarter of 2004.

Price risk management

EnCana's price risk mitigation strategy is intended to provide downside protection and deliver greater certainty of cash flows and returns on investments. Detailed risk management positions at September 30, 2005 are presented in Note 12 to the unaudited third quarter consolidated financial statements. In the third quarter of 2005, EnCana's financial price risk management measures resulted in realized losses of approximately $135 million after-tax, comprised of a $52 million loss on oil hedges, an $88 million loss on gas hedges and a $5 million gain on other hedges. A review of the company's hedging strategy in 2004 resulted in more frequent use of put options to protect downside but which do not limit upside in a rising price environment.

About 80 percent of 2006 forecast gas sales is exposed to price upside, while about 46 percent has downside price protection. About 91 percent of 2006 forecast oil and NGLs sales is exposed to price upside, while about 46 percent has downside protection. Overall, on a Mcfe basis, about 82 percent of EnCana's forecast 2006 sales are exposed to market price upside.

EnCana Continuing Operations Highlights
US$ and U.S. protocols

Financial Highlights (as at and for the period ended September 30) ($ millions)	**Q3 2005**	Q3 2004	% Δ	**9 months 2005**	9 months 2004	% Δ
Revenues, net of royalties	**3,089**	2,320	+ 33	**9,331**	7,602	+ 23
Pre-tax cash flow	**1,992**	1,362	+ 46	**5,120**	3,687	+ 39
Less:						
Cash tax	**169**	103	+ 64	**477**	511	- 7
Cash flow	**1,823**	1,259	+ 45	**4,643**	3,176	+ 46
Net acquisitions & divestitures	**166**	(901)	n/a	**(1,664)***	1,034	n/a
Add:						
Core capital	**1,456**	963	+ 51	**4,389**	3,250	+ 35
Net capital investment	**1,622**	62	n/a	**2,725**	4,284	n/a
Net earnings	**266**	432	- 38	**927**	1,023	- 9
Add (Deduct):						
Unrealized mark-to-market hedging loss, after-tax	**631**	276	+ 129	**1,058**	561	+ 89
Unrealized foreign exchange (gain) on translation of U.S. dollar debt issued in Canada, after-tax	**(166)**	(155)	+ 7	**(113)**	(98)	+ 15
Future tax (recovery) due to tax rate change	**-**	-	n/a	**-**	(109)	n/a
Operating earnings	**731**	553	+ 32	**1,872**	1,377	+ 36

* Includes proceeds from Gulf of Mexico sale of $2.1 billion, minus tax of $591 million

EnCana financial results in U.S. dollars and operating results according to U.S. protocols
EnCana reports in U.S. dollars and according to U.S. protocols in order to facilitate a more direct comparison to other North American upstream oil and natural gas exploration and development companies. Reserves and production are reported on an after-royalty basis.

Operating Highlights (for the period ended September 30) (After royalties)	**Q3 2005**	Q3 2004	% Δ	**9 months 2005**	9 months 2004	% Δ
North America Natural Gas sales (MMcf/d)	**3,222**	3,096	+ 4	**3,193**	2,928	+ 9
North America Oil and NGLs (bbls/d)	**150,457**	169,673	- 11	**154,892**	168,750	- 8
Total sales (MMcfe/d)	**4,125**	4,114	-	**4,122**	3,941	+ 5

Key resource play production growth up about 13 percent across EnCana's portfolio

Development capital continues to be focused on turning EnCana's Unbooked Resource Potential into reserves and production. Third quarter gas and oil production from key North American resource plays has increased approximately 13 percent since the third quarter of 2004. Year-over-year gas production growth is driven mainly by the Piceance basin in Colorado, coalbed methane on the legacy Palliser Block in Alberta and Cutbank Ridge in northeast British Columbia. Through much of 2005, gas production growth in the Piceance Basin remained flat as the company expands production in newer and less well-developed fields. The company has invested in building production infrastructure in these new areas and bringing efficiencies to drilling logistics, evidenced by recent production increases. Piceance Basin is currently producing about 320 million cubic feet per day and expects to grow 2005 average production by more than 17 percent, compared to 2004. The successful application of a water flood at Pelican Lake in northeast Alberta helped grow oil production by about 26 percent in the past year. Foster Creek's steam-assisted gravity drainage project is expanding from 30,000 to 60,000 barrels per day of production over the next year. The first 10,000 barrels per day of additional volumes is scheduled to start late this year.

Growth from key North American resource plays

Resource Play	Daily Production									
	2005				2004					2003
(After royalties)	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas (MMcf/d)										
Jonah	**429**	**440**	416	431	389	404	373	387	394	374
Piceance	**300**	**302**	302	300	261	291	282	251	218	151
East Texas	**87**	**94**	85	82	50	83	81	36	-	-
Fort Worth	**64**	**66**	63	61	27	34	31	23	21	7
Greater Sierra	**217**	**225**	228	195	230	211	244	247	216	143
Cutbank Ridge	**81**	**105**	80	56	40	50	45	41	22	3
CBM	**50**	**62**	51	38	17	27	19	11	10	4
Shallow Gas	**624**	**616**	633	625	592	629	595	590	554	507
Oil (Mbbls/d)										
Foster Creek	**27**	**27**	24	30	29	28	29	30	28	22
Pelican Lake	**25**	**27**	27	21	19	23	22	15	15	16
Total (MMcfe/d)	**2,166**	**2,235**	2,166	2,096	1,892	2,034	1,976	1,858	1,696	1,416
% change from prior year's quarter		**13.1**	16.6	23.6						
% change from prior period		**3.2**	3.3	3.0	33.6	2.9	6.4	9.6	7.1	

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled									
	2005				2004					2003
	YTD	Q3	Q2	Q1	Full year	Q4	Q3	Q2	Q1	Full Year
Natural Gas										
Jonah	**83**	**25**	30	28	70	21	17	21	11	59
Piceance	**211**	**69**	65	77	250	47	66	66	71	284
East Texas	**64**	**21**	22	21	50	23	20	7	-	-
Fort Worth	**39**	**18**	12	9	36	8	10	10	8	5
Greater Sierra	**139**	**33**	47	59	187	18	13	21	135	199
Cutbank Ridge	**101**	**40**	38	23	50	17	12	4	17	20
CBM	**757**	**216**	219	322	760	234	347	98	81	267
Shallow Gas	**979**	**341**	365	273	1,552	222	384	416	530	2,366
Oil										
Foster Creek	**26**	**14**	2	10	11	7	-	-	4	8
Pelican Lake	**56**	**3**	34	19	92	-	33	30	29	134
Total net wells	**2,455**	**780**	834	841	3,058	597	902	673	886	3,342

Corporate developments

EnCana CEO to step down at year-end; COO Randy Eresman to succeed Gwyn Morgan

On October 25, 2005, EnCana's founding President & Chief Executive Officer Gwyn Morgan announced his intention to step down at year-end. He will remain an officer of the company in the role of Executive Vice-Chairman for the year 2006, working mainly in an advisory capacity to the new Chief Executive Officer.

EnCana's board of directors also announced the appointment of Randall K. Eresman as President & Chief Executive Officer and a Director, effective January 1, 2006. A petroleum engineering graduate from the University of Wyoming, Eresman joined EnCana predecessor company Alberta Energy Company Ltd. (AEC) in 1980. He played a key role in the building of AEC and was appointed Chief Operating Officer of EnCana soon after its creation in 2002.

Quarterly dividend of 7.5 cents per share declared

EnCana's board of directors has declared a quarterly dividend of 7.5 cents per share which is payable on December 30, 2005 to common shareholders of record as of December 15, 2005.

EnCana renews Normal Course Issuer Bid

EnCana has received approval for renewal of the company's Normal Course Issuer Bid from Toronto Stock Exchange (TSX). Under the renewed bid, EnCana may purchase for cancellation up to 85,603,640 of its common shares, representing 10 percent of the public float of approximately 856,036,400 common shares outstanding as at October 25, 2005. EnCana plans to fund its share purchases under the renewed bid with proceeds from planned asset divestitures and cash flow. In the past 12 months under its previous Normal Course Issuer Bid, EnCana purchased 84,208,100 common shares, representing approximately 9.1 percent of the company's outstanding shares on October 22, 2004, at an average price of approximately US$32.05 per common share. Purchases under the renewed bid may commence on October 31, 2005 and may be made until October 30, 2006. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies, and may also be made through the facilities of the New York Stock Exchange (NYSE) in accordance with its rules. Approval of the bid is not required from the NYSE. The price to be paid will be the market price at the time of acquisition. EnCana believes that the purchase of its common shares will help create value for the company's shareholders.

Changes in Share Capital (millions of shares)	First 9 months 2005	Full Year 2004	% Δ
Common shares outstanding, beginning of period	**900.6**	921.2	- 2.2
Shares issued under option plan	**13.9**	19.4	
Shares purchased under Normal Course Issuer Bid	**(60.7)**	(40.0)	
Common shares outstanding, end of period	**853.8**	900.6	- 5.2

2006 capital investment

EnCana's 2006 budget is directed towards continuing to achieve strong production growth from the company's portfolio of sustainable, long-term resource plays across North America. Capital investment is forecast to increase in 2006 due to service industry inflation and the high levels of field activity, both of which are fuelled by the strong commodity price environment EnCana benefits from. The company's tempered growth rate of between 5 and 9 percent is a measured pace that's designed to enhance capital efficiency as the company converts its proved reserves and Unbooked Resource Potential into sales growth and free cash flow for reinvestment in attractive shareholder returns.

EnCana capital investment forecast by type ($ billions)	2005	2006
Upstream		
Maintain production[1]	2.6	2.9 - 3.1
Achieve current year's growth[1]	1.8	2.1 - 2.2
Oilsands	0.4	0.5 - 0.5
International	0.1	0.1 - 0.1
Other long-lead time growth	0.6	0.6 - 0.6
Sub-total	5.5	6.2 - 6.5
Midstream (Entrega Pipeline) and Corporate	0.4	0.4 - 0.5
Core Capital Investment	5.9	6.6 - 7.0
Acquisitions[2]	0.4	n/a
Divestitures[3]	(3.8 - 4.4)	n/a
Net acquisitions and divestitures	(3.4 - 4.0)	(0.5 - 1.5)
Discontinued Operations	0.2	n/a
Net Capital Investment (forecast)	**2.7 - 2.1**	**6.1 - 5.5**

1 Excludes oilsands
2 2005 represents miscellaneous acquisitions including the Maverick Basin of Texas
3 2005 includes sale of Canadian conventional oil, Gulf of Mexico assets and the pending sale of Ecuador assets

Financial strength

At September 30, 2005 the company's net debt-to-capitalization ratio was 40:60. Completion of planned asset divestitures, including EnCana's businesses in Ecuador, natural gas liquids processing and natural gas storage, is expected to generate sales proceeds in the range of $2.5 billion to $3.5 billion. EnCana's net debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.6 times. In the third quarter of 2005, EnCana invested $1.46 billion of core capital. Acquisitions and divestitures resulted in net investment of $166 million, resulting in net capital investment of $1.62 billion during the third quarter. Not surprisingly, with strong commodity prices, cash taxes as a percent of pre-tax cash flow are also expected to be higher in 2006 as outlined in EnCana's corporate guidance.

Updated corporate guidance
EnCana has updated its 2005 corporate guidance and has posted new corporate guidance for 2006 on its website: www.encana.com.

EnCana Corporation
With an enterprise value of approximately US$52 billion, EnCana is one of North America's leading natural gas producers, is among the largest holders of gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana delivers predictable, reliable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average decline rates and very long producing lives compared to conventional plays. The application of technology to unlock the huge resource potential of these plays typically results in continuous increases in production and reserves and decreases in costs over multiple decades of resource play life. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

NOTE 1: Non-GAAP measures
This news release contains references to cash flow, pre-tax cash flow, cash flow from continuing operations, operating earnings from continuing operations, total operating earnings and EBITDA. Total operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain on the sale of discontinued operations, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates. Management believes these items reduce the comparability of the company's underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. EBIDTA is a non-GAAP measure that shows net earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation and depletion, depreciation and amortization. These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

ADVISORY REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION – EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). EnCana's reserves quantities represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

In this news release, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the same basis. BOE and cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head. EnCana defines Unbooked Resource Potential as quantities of oil and gas on existing land holdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements in this news release include, but are not limited to: future economic and operating performance; anticipated future cash flow; anticipated cash taxes in 2006; anticipated growth and success of resource plays and the expected characteristics of resource plays; the planned sale of interests in Ecuador, the midstream NGLs business unit and the natural gas storage business and the timing of such potential transactions; the expected proceeds from planned divestitures and the use of proceeds from divestitures for share purchases under the company's Normal Course Issuer Bid program and debt repayment; projections with respect to the company's Unbooked Resource Potential and projected future production growth; expected debt levels and debt to capitalization ratios; anticipated expiry of certain commodity hedge positions; the potential success of projects such as Entrega, Brazil, Maverick Basin and Cutbank Doig; anticipated production from the Sinclair Doig; estimates of original gas in place; the belief in the similarity of characteristics of the Cutbank Doig to the Sinclair Doig; anticipated effect of EnCana's market risk mitigation strategy and EnCana's ability to participate in commodity price upside; anticipated purchases pursuant to the Normal Course Issuer Bid; anticipated production in 2005 and beyond; anticipated drilling; the capacity of the company's steam-assisted gravity drainage expansion project at Foster Creek and the timing thereof; anticipated expansion of the company's oilsands resources; potential capital expenditures and investment and the impact of inflation; potential oil, natural gas and NGLs sales in 2005 and beyond; anticipated ability to meet production, operating cost, cash tax and sales guidance targets; anticipated costs and the ability to mitigate against drilling costs increases; anticipated commodity prices; projections relating to project returns from EnCana's North American resource plays and potential risks associated with drilling and references to potential exploration. 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 reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved 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 or the interpretations of such regulations; political and economic conditions in the countries in which the company operates, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. 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.

MANAGEMENT'S DISCUSSION & ANALYSIS

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 ("Interim Consolidated Financial Statements") for the period ended September 30, 2005, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2004. Readers are referred to the legal advisory detailing "Forward-Looking Statements" contained at the end of this MD&A. The Interim Consolidated Financial Statements and comparative information have been prepared in accordance with Canadian GAAP in United States dollars (except where indicated as being in another currency).

This MD&A has been prepared in United States dollars with production and sales volumes presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated October 27, 2005.

SUMMARY OF KEY SECTIONS

Certain terms used in this MD&A (and not otherwise defined) are defined in the notes regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana, found at the end of this MD&A.

SUMMARY OF KEY EVENTS AND FINANCIAL RESULTS

Key events in the third quarter of 2005:

- Cash flow from continuing operations increased 45 percent to $1,823 million compared with $1,259 million in 2004;
- Net earnings from continuing operations decreased 38 percent to $266 million compared with $432 million in 2004;
- Operating earnings from continuing operations increased 32 percent to $731 million compared with $553 million in 2004;

- Sales volumes from continuing operations were 4,125 million cubic feet equivalent per day ("MMcfe/d"), relatively unchanged compared to the same period in 2004, comprised of 3,222 million cubic feet per day ("MMcf/d") of natural gas and 150,457 barrels per day ("bbls/d") of liquids. Natural gas volumes in the United States increased 15 percent to 1,099 MMcf/d while natural gas volumes in Canada were relatively unchanged at 2,123 MMcf/d. Liquids volumes decreased 11 percent to 150,457 bbls/d. Natural gas and liquids volumes in Canada decreased as a result of dispositions over the past year;
- Average sales prices, excluding financial hedges, increased 41 percent for North American natural gas and 44 percent for North American liquids compared with the same period in 2004;
- EnCana announced that it had reached an agreement to sell all of its shares in subsidiaries which have oil and pipeline interests in Ecuador for $1.42 billion;
- EnCana recorded realized commodity hedging losses from continuing operations of $135 million after-tax ($115 million after-tax in 2004) and unrealized commodity hedging losses of $631 million after-tax ($276 million after-tax in 2004); and
- EnCana completed the redemption of nine issues of Canadian medium term notes with an aggregate principal amount of C$1.15 billion for a total cost of C$1.3 billion.

Key events year-to-date in 2005:

- Cash flow from continuing operations increased 46 percent to $4,643 million compared with $3,176 million in 2004;
- Net earnings from continuing operations decreased nine percent to $927 million compared with $1,023 million in 2004;
- Operating earnings from continuing operations increased 36 percent to $1,872 million compared with $1,377 million in 2004;
- Sales volumes from continuing operations increased five percent to 4,122 MMcfe/d, natural gas volumes increased nine percent to 3,193 MMcf/d and liquids volumes decreased eight percent to 154,892 bbls/d;
- Average sales prices, excluding financial hedges, increased 23 percent for North American natural gas and 26 percent for North American liquids;
- EnCana announced that it had reached an agreement to sell all of its shares in subsidiaries which have oil and pipeline interests in Ecuador for $1.42 billion;
- EnCana sold its Gulf of Mexico assets for net proceeds of approximately $1.5 billion after-tax and other adjustments and sold certain non-core conventional oil and gas assets for proceeds of $440 million before adjustments;
- EnCana recorded realized commodity hedging losses from continuing operations of $216 million after-tax ($309 million after-tax in 2004) and unrealized commodity hedging losses of $1,058 million after-tax ($561 million after-tax in 2004);
- EnCana completed the redemption of nine issues of Canadian medium term notes with an aggregate principal amount of C$1.15 billion for a total cost of C$1.3 billion; and
- EnCana purchased approximately 55 million shares under the Normal Course Issuer Bid ("Bid") for a total cost of $1,924 million, bringing our total purchases under the Bid to 91 percent of the maximum purchases allowable under the Bid.

OVERVIEW

EnCana is a leading independent North American based oil and gas company. EnCana pursues predictable, profitable growth from its portfolio of long-life resource plays in Canada and the United States. EnCana's disciplined pursuit of these unconventional resources has enabled it to become North America's leading natural gas producer and a technical and cost performance leader in the development of oilsands through in-situ recovery.

EnCana reports the results of its continuing operations under two operating segments:

- Upstream, which focuses on the Company's exploration for and development and production of natural gas, crude oil and natural gas liquids ("NGLs"), and other related activities; and
- Midstream & Market Optimization, which is conducted by the Midstream & Marketing division. Marketing undertakes market optimization activities to enhance the sale of Upstream's proprietary production. Market Optimization results reflect third party purchases and sales of product which provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. Midstream focuses on natural gas storage, NGLs processing and power generation.

BUSINESS ENVIRONMENT

NATURAL GAS

An extremely warm summer in North America combined with supply losses as a result of hurricane damage and high crude oil prices resulting in increased prices for alternative fuels have resulted in historically high average NYMEX gas prices in the third quarter.

Higher average AECO gas prices in the third quarter of 2005 compared with the same period in 2004 can be attributed to increased NYMEX prices partially offset by increased AECO/NYMEX basis differentials in the third quarter of 2005 compared to the third quarter of 2004. The AECO basis widened to $1.74 in the third quarter of 2005 from $0.70 in the same period in 2004. This increase was mainly due to a higher NYMEX price and the timing differences between settlements of the AECO and NYMEX contracts.

	Three months ended September 30			Nine months ended September 30			Year Ended
Natural Gas Price Benchmarks *(Average for the period)*	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
AECO Price *(C$/Mcf)*	**$ 8.17**	23%	$ 6.66	**$ 7.41**	11%	$ 6.69	$ 6.79
NYMEX Price *($/MMBtu)*	**8.49**	47%	5.76	**7.16**	23%	5.81	6.14
Rockies (Opal) Price *($/MMBtu)*	**6.71**	33%	5.06	**6.08**	21%	5.02	5.23
AECO/NYMEX Basis Differential *($/MMBtu)*	**1.74**	149%	0.70	**1.12**	44%	0.78	0.91
Rockies/NYMEX Basis Differential *($/MMBtu)*	**1.78**	154%	0.70	**1.08**	35%	0.80	0.91

CRUDE OIL

The West Texas Intermediate ("WTI") crude oil price was significantly higher in the third quarter of 2005 than the same period in 2004. The hurricane damage to the U.S. Gulf Coast production and refinery facilities in a market that was already supply constrained was a major factor in this price strength. Third quarter Canadian heavy oil differentials were significantly wider in dollar terms relative to the third quarter of 2004, due to the higher price for WTI and the wider Maya differential, which is the North American heavy crude benchmark. Strong asphalt markets in Canada in the third quarter helped support Canadian heavy oil prices relative to the Maya price. The Bow River Blend average sales price for the third quarter of 2005 was 73 percent of WTI, similar to its 72 percent of WTI value in the third quarter of 2004.

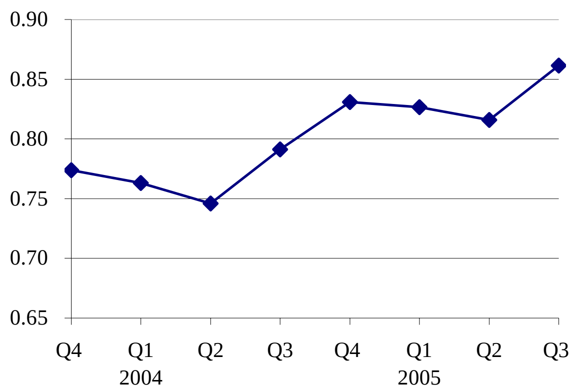
The NAPO blend average price for the third quarter of 2005 was 73 percent of WTI, up from 67 percent in the same period in 2004. This was primarily related to better refinery economics on NAPO crude which translates into higher value.

Crude Oil Price Benchmarks *(Average for the period $/bbl)*	Three months ended September 30 2005	2005 vs 2004	2004	Nine months ended September 30 2005	2005 vs 2004	2004	Year Ended 2004
WTI	**$ 63.31**	44%	$ 43.89	**$ 55.61**	42%	$ 39.21	$ 41.47
WTI/Maya Differential	**15.61**	34%	11.67	**15.34**	55%	9.89	11.58
WTI/Bow River Differential	**17.08**	41%	12.09	**18.59**	73%	10.72	12.82
WTI/OCP NAPO Differential (Ecuador)	**17.09**	19%	14.31	**16.70**	31%	12.71	14.33

U.S./CANADIAN DOLLAR EXCHANGE RATES

The September 30, 2005 U.S./Canadian dollar exchange rate of US$0.861 per C$1 increased by nine percent compared with the September 30, 2004 rate of $0.791. The September 2005 rate is approximately four percent higher than the 2004 year-end rate of $0.831.

U.S./Canadian Dollar Period End Exchange Rates



	Three months ended September 30 2005	Nine months ended September 30 2005	Year Ended 2004
Average U.S. / Canadian dollar exchange rate	$ 0.833	$ 0.817	$ 0.768
Average U.S. / Canadian dollar exchange rate for prior year	$ 0.765	$ 0.753	$ 0.716
Additional U.S. costs incurred for every C$100 spent on capital projects, operating & administrative expenses compared to prior year	$ 6.80	$ 6.40	$ 5.20

The impacts on results from the conversion of Canadian to U.S. dollars should be considered when analyzing specific components contained in the Interim Consolidated Financial Statements. Revenues were relatively unaffected by the increase in the exchange rate since commodity prices received are largely based in U.S. dollars or in Canadian dollar prices which are closely tied to the value of the U.S. dollar.

ACQUISITIONS AND DIVESTITURES

On September 13, 2005 EnCana announced that it had reached an agreement to sell all of its shares in subsidiaries which have crude oil and pipeline interests in Ecuador for approximately $1.42 billion. The sale will have an effective date of July 1, 2005. On October 27, 2005 EnCana announced that it had reached an agreement to sell substantially all of its natural gas liquids business for approximately $586 million before adjustments. Both of these sales are expected to close before year-end and are subject to closing conditions and approvals. EnCana continues with plans to divest of its natural gas storage business.

During the year, EnCana completed two significant transactions:

- On May 26, 2005, EnCana closed the sale of its Gulf of Mexico assets for approximately $2.1 billion in cash, resulting in net proceeds of approximately $1.5 billion after-tax and other adjustments; and
- On June 30, 2005, EnCana closed the sale of certain non-core Canadian conventional oil and gas assets producing approximately 6,400 barrels of oil equivalent per day for proceeds of approximately $326 million before adjustments.

Proceeds from these divestitures were directed primarily to a combination of debt reduction and the purchase of EnCana shares pursuant to EnCana's Normal Course Issuer Bid program.

CONSOLIDATED FINANCIAL RESULTS

Consolidated Financial Summary	Three months ended September 30			Nine months ended September 30			Year Ended
		2005 vs			2005 vs		
($ millions, except per share [1] amounts)	**2005**	2004	2004	**2005**	2004	2004	2004
Cash Flow[2]	**$ 1,931**	42%	$ 1,363	**$ 4,916**	41%	$ 3,489	$ 4,980
- per share - diluted	**2.20**	51%	1.46	**5.50**	47%	3.73	5.32
Net Earnings	**266**	-32%	393	**1,060**	14%	933	3,513
- per share - basic	**0.31**	-28%	0.43	**1.21**	20%	1.01	3.82
- per share - diluted	**0.30**	-29%	0.42	**1.19**	19%	1.00	3.75
Operating Earnings[3]	**704**	26%	559	**1,970**	40%	1,403	1,976
- per share diluted	**0.80**	33%	0.60	**2.20**	47%	1.50	2.11
Cash Flow from Continuing Operations[2]	**1,823**	45%	1,259	**4,643**	46%	3,176	4,605
Net Earnings from Continuing Operations	**266**	-38%	432	**927**	-9%	1,023	2,211
- per share - basic	**0.31**	-34%	0.47	**1.06**	-5%	1.11	2.40
- per share - diluted	**0.30**	-35%	0.46	**1.04**	-5%	1.10	2.36
Operating Earnings from Continuing Operations [3]	**731**	32%	553	**1,872**	36%	1,377	1,989
Revenues, Net of Royalties	**3,089**	33%	2,320	**9,331**	23%	7,602	11,810

Quarterly Summary	**2005**			2004				2003
($ millions, except per share [1] amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Cash Flow[2]	$ 1,931	$ 1,572	$ 1,413	$ 1,491	$ 1,363	$ 1,131	$ 995	$ 1,254
- per share - diluted	2.20	1.76	1.55	1.60	1.46	1.21	1.07	1.35
Net Earnings (Loss)	266	839	(45)	2,580	393	250	290	426
- per share - basic	0.31	0.96	(0.05)	2.81	0.43	0.27	0.31	0.46
- per share - diluted	0.30	0.94	(0.05)	2.77	0.42	0.27	0.31	0.46
Operating Earnings[3]	704	655	611	573	559	379	465	316
- per share - diluted	0.80	0.73	0.67	0.62	0.60	0.41	0.50	0.34
Cash Flow from Continuing Operations[2]	1,823	1,512	1,308	1,429	1,259	1,021	896	1,103
Net Earnings (Loss) from Continuing Operations	266	786	(125)	1,188	432	265	326	447
- per share - basic	0.31	0.90	(0.14)	1.29	0.47	0.29	0.35	0.49
- per share - diluted	0.30	0.88	(0.14)	1.28	0.46	0.28	0.35	0.48
Operating Earnings from Continuing Operations[3]	731	623	518	612	553	362	462	337
Revenues, Net of Royalties	3,089	3,581	2,661	4,208	2,320	2,552	2,730	2,639

(1) Per share amounts have been restated for the effect of the common share split in May 2005.

(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are discussed under "Cash Flow" in this MD&A.

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under Operating Earnings in this MD&A.

CASH FLOW

EnCana's total 2005 third quarter cash flow was $1,931 million, an increase of $568 million from the same period in 2004. This increase reflects increased commodity prices in the third quarter of 2005 partially reduced by higher realized financial hedge losses and increased costs. EnCana's discontinued operations contributed $108 million to cash flow compared with $104 million from the same period in 2004.

EnCana's 2005 third quarter cash flow from continuing operations increased $564 million to $1,823 million compared with the same period in 2004 with significant items as follows:

- Natural gas sales volumes increased four percent to 3,222 MMcf/d;
- Average North American natural gas prices, excluding financial hedges, increased 41 percent to $7.29 per Mcf compared to $5.18 per Mcf in the same period of 2004;
- Average North American liquids prices, excluding financial hedges, increased 44 percent to $46.16 per bbl in 2005 compared to $32.03 per bbl in the same period of 2004;
- Realized financial commodity hedge losses included in cash flow from continuing operations were $135 million after-tax in 2005 compared to $115 million after-tax for the same period in 2004;
- Operating expenses increased 27 percent to $432 million in 2005 compared with $340 million in 2004; and
- The current income tax provision was $169 million in 2005 compared with $103 million in 2004.

EnCana's total 2005 year-to-date cash flow was $4,916 million, an increase of $1,427 million from the same period in 2004. This increase reflects the net impact of increased prices and lower realized hedge losses for the first nine months in 2005 partially reduced by increased costs. EnCana's discontinued operations contributed $273 million to cash flow compared with $313 million in 2004.

EnCana's 2005 year-to-date cash flow from continuing operations increased $1,467 million to $4,643 million compared with the same period in 2004 with significant items as follows:

- Natural gas sales volumes increased nine percent to 3,193 MMcf/d;
- Average North American natural gas prices, excluding financial hedges, increased 23 percent to $6.46 per Mcf compared to $5.26 per Mcf in the same period of 2004;
- Average North American liquids prices, excluding financial hedges, increased 26 percent to $35.82 per bbl in 2005 compared to $28.32 per bbl in the same period of 2004;
- Realized financial commodity hedge losses included in cash flow from continuing operations were $216 million after-tax in 2005 compared to $309 million after-tax for the same period in 2004;
- Operating expenses increased 23 percent to $1,177 million in 2005 compared with $960 million in 2004; and
- The current income tax provision excluding income tax on the sale of assets was $477 million in 2005 compared with $511 million in 2004.

Cash flow measures are considered non-GAAP but are commonly used in the oil and gas industry to assist management and investors to measure the Company's ability to finance its capital programs and meet its financial obligations. The calculation of cash flow is disclosed in the Consolidated Statement of Cash Flows in the Interim Consolidated Financial Statements.

NET EARNINGS

EnCana's 2005 total third quarter net earnings were $266 million compared with $393 million in the same period in 2004. EnCana's 2005 third quarter net earnings from continuing operations were $266 million, a decrease of $166 million compared with 2004. In addition to the items affecting third quarter cash flow from continuing operations as detailed previously, significant items are:

- Unrealized mark-to-market losses of $631 million after-tax in 2005 compared with a loss of $276 million in the same period in 2004;
- A $166 million after-tax unrealized gain on Canadian issued U.S. dollar debt in 2005 compared with a $155 million gain in 2004; and
- Interest expense was $218 million in 2005 compared with $106 million in 2004.

EnCana's total 2005 year-to-date net earnings were $1,060 million compared with $933 million in the same period in 2004. EnCana's year-to-date net earnings from continuing operations were $927 million, a decrease of $96 million in 2005 compared with 2004. In addition to the items affecting cash flow from continuing operations as detailed previously, significant items are:

- Unrealized mark-to-market losses of $1,058 million after-tax in 2005 compared to $561 million in the same period in 2004;
- A $113 million after-tax unrealized gain on Canadian issued U.S. dollar debt to-date in 2005 compared with a $98 million gain in 2004;
- Interest expense was $419 million in 2005 compared with $284 million in 2004;
- An increase in depreciation, depletion and amortization ("DD&A") of $277 million as a result of the impact of the higher value of the Canadian dollar and higher DD&A rates resulting from the impacts of foreign exchange, increased future development costs, the Tom Brown, Inc. ("TBI") acquisition in May 2004 and increased sales volumes; and
- Included in 2004 is a gain due to a change in income tax rates of $109 million, with no comparable amount in 2005.

Reconciliation of Net Earnings from Continuing Operations from 2004 to 2005
($ millions)

2004 year-to-date net earnings from continuing operations	**$ 1,023**
Upstream prices	1,281 [1]
Upstream volumes	341
Realized loss on financial contracts	142
Gain on disposition	(35)
Interest, net	(132) [2]
Foreign exchange loss	(150)
Income tax	(211)
Upstream expenses	(291)
DD&A expenses	(277)
Unrealized fair value adjustment on financial contracts	(742)
Other	(22)
2005 year-to-date net earnings from continuing operations	**$ 927**

(1) Excludes the effect of Upstream financial hedging that is included in the Realized loss on financial contracts.
(2) Excludes the effect of interest rate swaps that is included in the Realized loss on financial contracts.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that show net earnings excluding non-operating items such as the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates. Management believes these items reduce the comparability of the Company's underlying financial performance between periods. The majority of the unrealized gains or losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years. The following table has been prepared in order to provide investors with information that is more comparable between years.

Summary of total Operating Earnings	Three months September 30			Nine months ended September 30			Year Ended
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
Net Earnings, as reported	**$ 266**	-32%	$ 393	**$ 1,060**	14%	$ 933	$ 3,513
Deduct: Gain on discontinuance	-		-	-		-	(1,364)
Add: Unrealized mark-to-market accounting loss (after-tax)	**604**		321	**1,023**		677	165
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(166)**		(155)	**(113)**		(98)	(229)
Deduct: Future tax recovery due to tax rate reductions	-		-	-		(109)	(109)
Operating Earnings [1][3]	**$ 704**	26%	$ 559	**$ 1,970**	40%	$ 1,403	$ 1,976
($ per Common Share - Diluted)							
Net Earnings, as reported	**$ 0.30**	-29%	$ 0.42	**$ 1.19**	19%	$ 1.00	$ 3.75
Deduct: Gain on discontinuance	-		-	-		-	(1.46)
Add: Unrealized mark-to-market accounting loss (after-tax)	**0.69**		0.35	**1.14**		0.72	0.18
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(0.19)**		(0.17)	**(0.13)**		(0.10)	(0.24)
Deduct: Future tax recovery due to tax rate reductions	-		-	-		(0.12)	(0.12)
Operating Earnings [1][3]	**$ 0.80**	33%	$ 0.60	**$ 2.20**	47%	$ 1.50	$ 2.11

Summary of Operating Earnings from Continuing Operations	Three months ended September 30			Nine months ended September 30			Year Ended
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004	2004
Net Earnings from Continuing Operations, as reported	**$ 266**	-38%	$ 432	**$ 927**	-9%	$ 1,023	$ 2,211
Add: Unrealized mark-to-market accounting loss (after-tax)	**631**		276	**1,058**		561	116
Deduct: Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt (after-tax)	**(166)**		(155)	**(113)**		(98)	(229)
Deduct: Future tax recovery due to tax rate reductions	-		-	-		(109)	(109)
Operating Earnings from Continuing Operations [2][3]	**$ 731**	32%	$ 553	**$ 1,872**	36%	$ 1,377	$ 1,989

(1) Operating Earnings is a non-GAAP measure that shows net earnings excluding the after-tax gain or loss from the disposition of discontinued operations, the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(2) Operating Earnings from Continuing Operations is a non-GAAP measure that shows net earnings from continuing operations excluding the after-tax effects of unrealized mark-to-market accounting for derivative instruments, the after-tax gain or loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the changes in statutory income tax rates.

(3) Unrealized gains or losses have no impact on cash flow.

RESULTS OF OPERATIONS

UPSTREAM OPERATIONS

Financial Results from Continuing Operations

Three months ended September 30

($ millions)	2005				2004			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 2,043**	**$ 561**	**$ 76**	**$ 2,680**	$ 1,432	$ 363	$ 66	$ 1,861
Expenses								
Production and mineral taxes	**96**	**11**	**-**	**107**	69	10	-	79
Transportation and selling	**119**	**14**	**-**	**133**	95	19	-	114
Operating	**190**	**73**	**85**	**348**	131	71	60	262
Operating Cash Flow	**$ 1,638**	**$ 463**	**$ (9)**	**$ 2,092**	$ 1,137	$ 263	$ 6	$ 1,406
Depreciation, depletion and amortization				**649**				583
Upstream Income				**$ 1,443**				$ 823

Nine months ended September 30

($ millions)	2005				2004			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 5,525**	**$ 1,293**	**$ 195**	**$ 7,013**	$ 4,085	$ 998	$ 170	$ 5,253
Expenses								
Production and mineral taxes	**254**	**37**	**-**	**291**	188	28	-	216
Transportation and selling	**345**	**45**	**-**	**390**	315	55	-	370
Operating	**525**	**222**	**189**	**936**	377	208	155	740
Operating Cash Flow	**$ 4,401**	**$ 989**	**$ 6**	**$ 5,396**	$ 3,205	$ 707	$ 15	$ 3,927
Depreciation, depletion and amortization				**1,957**				1,657
Upstream Income				**$ 3,439**				$ 2,270

Three Months Ended September 30

Results from continuing operations for the quarter ended September 30, 2005 compared with the same quarter in 2004 reflect growth in sales volumes from North American resource plays offset by non-core property dispositions in the third quarter of 2004 and June 2005.

Revenues, net of royalties, reflect the increase in the quarter over quarter natural gas and crude oil benchmark prices (see the “Business Environment” section of this MD&A) offset by the realized hedging losses. Realized financial commodity hedging losses for the three months ended September 30, 2005 were $196 million, or $0.52 per Mcfe compared to $180 million or $0.48 per Mcfe for the same period in 2004.

North American production and mineral taxes increased by 35 percent or $28 million during the third quarter of 2005 compared to the same period in 2004 primarily due to increased natural gas and crude oil prices and increased natural gas volumes in the United States.

North American transportation and selling costs increased by 17 percent or $19 million during the third quarter of 2005 compared with the same quarter in 2004. In 2005, costs have increased as a result of both the marketing of gas volumes for several U.S. properties downstream of the wellhead which were marketed at the wellhead in 2004 and a growth in volumes.

For the three months ended September 30, 2005, operating expenses excluding Other were $61 million higher, an increase of $0.16 per Mcfe to $0.69 per Mcfe compared to $0.53 per Mcfe for the same period in 2004. This increase is primarily due to an increase in the average U.S./Canadian dollar exchange rate during 2005, an increase in long-term compensation expenses due to the higher EnCana share price and rising costs as a result of increased industry activity.

DD&A expense increased by $66 million for the quarter ended September 30, 2005 compared to the same quarter in 2004 primarily as a result of higher DD&A rates and the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense. On a continuing operations basis, excluding Other activities, DD&A rates were $1.69 per Mcfe for the third quarter of 2005 compared to $1.52 per Mcfe for the same quarter of 2004. DD&A rates have increased in 2005 due to the impact of foreign exchange and increased future development costs offset somewhat by the disposition of the Gulf of Mexico assets which has reduced the DD&A rate effective June 1, 2005.

Nine Months Ended September 30

Results from continuing operations reflect a five percent or 181 MMcfe/d increase in sales volumes for the nine months ended September 30, 2005 compared with the same period in 2004. The increase in sales volumes is primarily attributable to organic growth from North American resource plays. The increase from the TBI acquisition in May 2004 is offset by non-core property dispositions in 2004 and 2005.

Revenues, net of royalties, reflect the increase in year-to-date natural gas and crude oil benchmark prices (see the “Business Environment” section of this MD&A) offset by the realized hedging losses. Realized financial commodity hedging losses for the nine months ended September 30, 2005 were $330 million, or $0.29 per Mcfe compared to $443 million or $0.41 per Mcfe for the same period in 2004.

North American production and mineral taxes increased by 35 percent or $75 million in the first nine months of 2005 compared to the same period in 2004 primarily due to higher natural gas and crude oil prices and increased natural gas volumes in the United States including the 2004 acquisition of TBI properties.

For the nine months ended September 30, 2005, operating expenses excluding Other were $162 million higher, an increase of $0.12 per Mcfe to $0.66 per Mcfe compared to $0.54 per Mcfe for the same period in 2004. This increase is primarily due to an increase in the average U.S./Canadian dollar exchange rate during 2005, an increase in long-term compensation expenses due to the higher EnCana share price and rising costs as a result of increased industry activity.

DD&A expense increased by $300 million for the first nine months of 2005 compared to the first nine months of 2004 primarily as a result of higher DD&A rates, the impact of the higher value of the Canadian dollar compared to the U.S. dollar applied to Canadian dollar denominated DD&A expense and increased sales volumes. On a continuing operations basis, excluding other activities, DD&A rates were $1.72 per Mcfe for the first nine months of 2005 compared to $1.51 per Mcfe in the first nine months of 2004. DD&A rates have increased in 2005 due to the impacts of foreign exchange, increased future development costs and the TBI acquisition.

Revenue Variances for the Third Quarter of 2005 Compared to the Third Quarter of 2004 from Continuing Operations

Three months ended September 30
($ millions)

	2004 Revenues, Net of Royalties	Revenue Variances in: Price(1)	Volume	2005 Revenues, Net of Royalties
Produced Gas				
Canada	$ 970	$ 356	$ (9)	$ 1,317
United States	462	171	93	726
Total Produced Gas	$ 1,432	$ 527	$ 84	$ 2,043
Crude Oil and NGLs				
Canada	$ 313	$ 244	$ (67)	$ 490
United States	50	24	(3)	71
Total Crude Oil and NGLs	$ 363	$ 268	$ (70)	$ 561

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 98 percent of the change in revenues, net of royalties, for the third quarter of 2005 compared with the third quarter of 2004.

The revenue variances due to volumes in Canada for the third quarter of 2005 compared with the third quarter of 2004 were mainly due to the dispositions of mature conventional producing assets during the third quarter of 2004 and June 2005.

Revenue Variances for the First Nine Months of 2005 Compared to the First Nine Months of 2004 from Continuing Operations

Nine months ended September 30
($ millions)

	2004 Revenues, Net of Royalties	Revenue Variances in: Price(1)	Volume	2005 Revenues, Net of Royalties
Produced Gas				
Canada	$ 2,887	$ 738	$ 9	$ 3,634
United States	1,198	255	438	1,891
Total Produced Gas	$ 4,085	$ 993	$ 447	$ 5,525
Crude Oil and NGLs				
Canada	$ 883	$ 359	$ (129)	$ 1,113
United States	115	42	23	180
Total Crude Oil and NGLs	$ 998	$ 401	$ (106)	$ 1,293

(1) Includes realized commodity hedging impacts.

The increase in sales prices accounts for approximately 80 percent of the change in revenues, net of royalties, for the first nine months of 2005 compared with the first nine months of 2004.

The crude oil and NGLs volume variance in Canada was mainly due to the dispositions of mature conventional oil producing assets during the third quarter of 2004 and June 2005.

Quarterly Sales Volumes	2005			2004				2003
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Produced Gas *(million cubic feet per day)*	**3,222**	3,212	3,146	3,087	3,096	3,001	2,684	2,662
Crude Oil *(barrels per day)*	**124,402**	132,294	130,826	132,061	142,506	144,347	142,669	151,644
NGLs *(barrels per day)*	**26,055**	24,814	26,358	27,409	27,167	26,340	23,208	22,827
Continuing Operations *(million cubic feet equivalent per day)* (1)	**4,125**	4,155	4,089	4,044	4,114	4,025	3,679	3,709
Discontinued Operations								
Ecuador *(barrels per day)*	**68,710**	73,176	72,487	77,876	74,846	78,303	80,982	77,352
United Kingdom *(barrels of oil equivalent per day)* (2)	-	-	-	13,927	20,222	26,728	22,755	18,400
Discontinued Operations *(million cubic feet equivalent per day)* (1)	**412**	439	435	551	570	630	623	574
Total *(million cubic feet equivalent per day)* (1)	**4,537**	4,594	4,524	4,595	4,684	4,655	4,302	4,283

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Includes natural gas and liquids (converted to BOE).

Sales Volumes	Three months ended September 30			Nine months ended September 30		
	2005	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Produced Gas *(million cubic feet per day)*	**3,222**	4%	3,096	**3,193**	9%	2,928
Crude Oil *(barrels per day)*	**124,402**	-13%	142,506	**129,151**	-10%	143,172
NGLs *(barrels per day)*	**26,055**	-4%	27,167	**25,741**	1%	25,578
Continuing Operations *(million cubic feet equivalent per day)* (1)	**4,125**	-	4,114	**4,122**	5%	3,941
Discontinued Operations						
Ecuador *(barrels per day)*	**68,710**	-8%	74,846	**71,443**	-8%	78,032
United Kingdom *(barrels of oil equivalent per day)* (2)	-	-100%	20,222	-	-100%	23,223
Discontinued Operations *(million cubic feet equivalent per day)* (1)	**412**	-28%	570	**429**	-29%	607
Total *(million cubic feet equivalent per day)* (1)	**4,537**	-3%	4,684	**4,551**	-	4,548

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) Includes natural gas and liquids (converted to BOE).

Three Months Ended September 30

In the three months ended September 30, 2005, sales volumes from continuing operations were relatively unchanged compared to the same quarter of 2004. Record setting wet weather in Western Canada and high levels of industry activity in the North American oil and gas services sector has restricted access to land and equipment which has directly impacted EnCana's ability to increase production during the quarter.

Canadian natural gas sales volumes during the third quarter of 2005 decreased approximately one percent or 15 MMcf/d from the comparable quarter in 2004. This decrease results mainly from the net divestiture of non-core properties during 2004 and 2005 offset by successful resource play drilling programs at Cutbank Ridge in northeast British Columbia and shallow gas and coalbed methane ("CBM") in southern Alberta. Natural gas sales volumes in the United States for the three months ended September 30, 2005 were higher by approximately 15 percent or 141 MMcf/d compared to the same period of 2004. This increase is primarily due to successful resource play drilling in the Piceance basin, at Jonah and East Texas and the Fort Worth property acquisition in December 2004.

Third quarter 2005 liquids sales volumes from continuing operations declined by 11 percent or 19,216 bbls/d compared to the third quarter of 2004. The lower liquids sales volumes were mainly due to non-core property dispositions in the third quarter of 2004 and June 2005, which were producing approximately 13,400 bbls/d, and delays in restoring Foster Creek production subsequent to the scheduled maintenance that occurred in the second quarter of 2005 (2,400 bbls/d) offset slightly by continued development at Pelican Lake.

Nine Months Ended September 30

In the first nine months of 2005, sales volumes from continuing operations were higher by five percent, or 181 MMcfe/d compared to the first nine months of 2004.

Canadian natural gas sales volumes during the first nine months of 2005 increased approximately one percent or 13 MMcf/d from the comparable period in 2004. This increase results mainly from successful resource play drilling programs at Cutbank Ridge in northeast British Columbia, shallow gas and CBM in southern Alberta and gas storage withdrawals of 9 MMcf/d in the first nine months of 2005. The growth in volumes was offset partially by the net divestiture of non-core properties which were producing approximately 63 MMcf/d during 2004. Natural gas sales volumes in the United States for the nine months ended September 30, 2005 were higher by approximately 31 percent or 252 MMcf/d compared to the same period of 2004. This increase is primarily due to a full nine months of the TBI acquisition volumes which added approximately 135 MMcf/d and successful resource play drilling in the Piceance basin and at Jonah.

In the first nine months of 2005, liquids sales volumes from continuing operations declined by eight percent or 13,858 bbls/d compared to the first nine months of 2004. The lower liquids sales volumes were mainly due to the disposition of non-core properties, including Petrovera Resources (“Petrovera”), in 2004 and June 2005, partially offset by continued development at Pelican Lake as well as incremental NGLs production from the TBI acquisition.

Per Unit Results - Produced Gas

Three months ended September 30

	Canada			United States		
($ per thousand cubic feet)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 7.18**	41%	$ 5.10	**$ 7.51**	40%	$ 5.36
Expenses						
Production and mineral taxes	**0.10**	11%	0.09	**0.75**	32%	0.57
Transportation and selling	**0.36**	-3%	0.37	**0.49**	88%	0.26
Operating	**0.68**	36%	0.50	**0.55**	53%	0.36
Netback	**$ 6.04**	46%	$ 4.14	**$ 5.72**	37%	$ 4.17
Gas Sales Volumes *(MMcf per day)*	**2,123**	-1%	2,138	**1,099**	15%	958

Nine months ended September 30

	Canada			United States		
($ per thousand cubic feet)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 6.33**	22%	$ 5.17	**$ 6.73**	23%	$ 5.49
Expenses						
Production and mineral taxes	**0.10**	25%	0.08	**0.68**	8%	0.63
Transportation and selling	**0.37**	-3%	0.38	**0.46**	44%	0.32
Operating	**0.65**	25%	0.52	**0.50**	39%	0.36
Netback	**$ 5.21**	24%	$ 4.19	**$ 5.09**	22%	$ 4.18
Gas Sales Volumes *(MMcf per day)*	**2,118**	1%	2,105	**1,075**	31%	823

Three Months Ended September 30

EnCana's realized natural gas prices for the third quarter of 2005 were $7.29 per Mcf, a 41 percent increase compared with 2004. For the three months ended September 30, 2005, North American realized financial commodity hedging losses on natural gas were approximately $117 million or $0.39 per Mcf compared to losses of approximately $43 million or $0.15 per Mcf in the same period in 2004.

Natural gas per unit production and mineral taxes in the U.S. for the three months ended September 30, 2005 compared to the same period in 2004 increased 32 percent or $0.18 per Mcf due to higher natural gas prices and volumes.

Natural gas per unit transportation and selling costs for the U.S. have increased 88 percent or $0.23 per Mcf for the three months ended September 30, 2005 compared to 2004, primarily as a result of marketing TBI and Fort Worth gas volumes downstream of the wellhead in 2005.

Canadian natural gas per unit operating expenses for the third quarter of 2005 were 36 percent or $0.18 per Mcf higher compared to the same period of 2004 due to the higher U.S./Canadian exchange rates and planned plant turnarounds at Hythe and Sexsmith that occurred in the third quarter of 2005. Increases in the U.S. natural gas per unit operating expenses of 53 percent or $0.19 per Mcf for the three months ended September 30, 2005 compared to the same period in 2004 were mainly a result of higher workovers and increased staffing levels attributable to growth. In addition, operating costs in both Canada and the U.S. were affected by higher long-term compensation expenses and rising costs resulting from increased industry activity during the third quarter of 2005.

Nine Months Ended September 30

EnCana's realized natural gas prices for the first nine months of 2005 were $6.46 per Mcf, a 23 percent increase compared with 2004. For the nine months ended September 30, 2005, North American realized financial commodity hedging losses on natural gas were approximately $108 million or $0.12 per Mcf compared to losses of approximately $133 million or $0.16 per Mcf in the same period in 2004.

Natural gas per unit production and mineral taxes in the U.S. for the nine months ended September 30, 2005 compared to 2004 increased eight percent or $0.05 per Mcf due to higher prices and volumes.

Natural gas per unit transportation and selling costs in Canada have decreased three percent or $0.01 per Mcf for the nine months ended September 30, 2005 compared to the same period in 2004 as a result of the expiration of long term transportation contracts offset partially by higher U.S./Canadian exchange rates. Per unit transportation and selling costs for the U.S. have increased 44 percent or $0.14 per Mcf for the nine months ended September 30, 2005 compared to 2004, primarily as a result of marketing TBI and Fort Worth gas volumes downstream of the wellhead in 2005.

Canadian natural gas per unit operating expenses for the first nine months of 2005 were 25 percent or $0.13 per Mcf higher compared to the same period of 2004 primarily due to the higher U.S./Canadian exchange rates and higher repairs and maintenance. Increases in the U.S. natural gas per unit operating expenses of 39 percent or $0.14 per Mcf for the nine months ended September 30, 2005 compared to the same period in 2004 were mainly a result of higher operating cost properties from the TBI acquisition. In addition, operating costs in both Canada and the U.S. were affected by higher long-term compensation expenses and rising costs resulting from increased industry activity during the first nine months of 2005.

Per Unit Results - Crude Oil North America

	Three months ended September 30			Nine months ended September 30		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 45.16**	43%	$ 31.49	**$ 34.06**	23%	$ 27.70
Expenses						
Production and mineral taxes	**0.48**	41%	0.34	**0.56**	60%	0.35
Transportation and selling	**1.15**	-19%	1.42	**1.23**	-10%	1.36
Operating	**6.45**	19%	5.42	**6.32**	19%	5.29
Netback	**$ 37.08**	53%	$ 24.31	**$ 25.95**	25%	$ 20.70
Crude Oil Sales Volumes *(bbls per day)*	**124,402**	-13%	142,506	**129,151**	-10%	143,172

Three Months Ended September 30

Increases in the average crude oil price in the third quarter of 2005, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 44 percent in 2005 compared to the same quarter of 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 41 percent). North American realized financial commodity hedging losses on crude oil were approximately $79 million or $5.70 per bbl of liquids in the third quarter of 2005 compared to losses of approximately $137 million or $8.75 per bbl of liquids in the same period in 2004.

North American crude oil per unit production and mineral taxes increased by 41 percent or $0.14 per bbl for the three months ended September 30, 2005 compared to the same period in 2004 primarily due to higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to freehold mineral tax and Saskatchewan resource tax, respectively.

North American crude oil per unit operating costs for the third quarter of 2005 have increased 19 percent or $1.03 per bbl compared to the same period in 2004 mainly due to the higher U.S./Canadian exchange rate, higher workovers, repairs and maintenance and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from steam assisted gravity drainage (“SAGD”) projects, which have higher operating costs compared to EnCana’s other properties, has resulted in an overall increase in crude oil per unit operating costs.

Nine Months Ended September 30

Increases in the average crude oil price in the first nine months of 2005, excluding the impact of financial hedges, reflect the increase in the benchmark WTI which increased 42 percent in 2005 compared to 2004. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 73 percent). North American realized commodity hedging losses on crude oil were approximately $222 million or $5.25 per bbl of liquids in 2005 compared to losses of approximately $310 million or $6.71 per bbl of liquids in 2004.

North American crude oil per unit production and mineral taxes increased by 60 percent or $0.21 per bbl in the first nine months of 2005 compared to the same period in 2004 primarily due to higher prices and increased production from southern Alberta and Saskatchewan properties which are subject to freehold mineral tax and Saskatchewan resource tax, respectively.

North American crude oil per unit operating costs for the first nine months of 2005 have increased 19 percent or $1.03 per bbl compared to the same period in 2004 mainly due to the higher U.S./Canadian exchange rate, higher workovers, repairs and maintenance and long-term compensation expenses. In addition, the increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana’s other properties, has resulted in an overall increase in crude oil operating costs. This increase was partially offset by the sale of Petrovera in February 2004 which had higher operating costs relative to EnCana's other properties.

Per Unit Results - NGLs

Three months ended September 30

	Canada			United States		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 47.39**	42%	$ 33.46	**$ 53.92**	49%	$ 36.09
Expenses						
Production and mineral taxes	-	-	-	**5.46**	35%	4.05
Transportation and selling	**0.48**	7%	0.45	**0.01**	-	-
Netback	**$ 46.91**	42%	$ 33.01	**$ 48.45**	51%	$ 32.04
NGLs Sales Volumes *(bbls per day)*	**11,924**	-7%	12,804	**14,131**	-2%	14,363

Nine months ended September 30

	Canada			United States		
($ per barrel)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Price	**$ 42.39**	43%	$ 29.65	**$ 46.57**	36%	$ 34.15
Expenses						
Production and mineral taxes	-	-	-	**4.68**	24%	3.77
Transportation and selling	**0.41**	5%	0.39	**0.01**	-	-
Netback	**$ 41.98**	43%	$ 29.26	**$ 41.88**	38%	$ 30.38
NGLs Sales Volumes *(bbls per day)*	**11,779**	-12%	13,452	**13,962**	15%	12,126

NGLs realized price changes generally correlate with changes in WTI oil prices. The strong WTI oil price in the third quarter and to-date in 2005 positively impacted NGLs prices.

U.S. NGLs per unit production and mineral taxes for the three months and nine months ended September 30, 2005 compared to the same periods in 2004 increased 35 percent or $1.41 per bbl and 24 percent or $0.91 per bbl respectively. The higher production and mineral taxes in the United States were a result of the increase in NGLs prices.

MIDSTREAM & MARKET OPTIMIZATION OPERATIONS

Financial Results

Three months ended September 30

($ millions)	2005			2004		
	Midstream	**Market Optimization**	**Total**	Midstream	Market Optimization	Total
Revenues	**$ 195**	**$ 1,153**	**$ 1,348**	$ 158	$ 731	$ 889
Expenses						
Transportation and selling	**-**	**6**	**6**	-	4	4
Operating	**67**	**18**	**85**	65	12	77
Purchased product	**115**	**1,129**	**1,244**	88	712	800
Operating Cash Flow	**$ 13**	**$ -**	**$ 13**	$ 5	$ 3	$ 8
Depreciation, depletion and amortization			**9**			8
Segment Income			**$ 4**			$ -

Nine months ended September 30

($ millions)	2005			2004		
	Midstream	**Market Optimization**	**Total**	Midstream	Market Optimization	Total
Revenues	**$ 930**	**$ 2,984**	**$ 3,914**	$ 881	$ 2,325	$ 3,206
Expenses						
Transportation and selling	**-**	**16**	**16**	-	20	20
Operating	**204**	**40**	**244**	192	32	224
Purchased product	**630**	**2,910**	**3,540**	655	2,254	2,909
Operating Cash Flow	**$ 96**	**$ 18**	**$ 114**	$ 34	$ 19	$ 53
Depreciation, depletion and amortization			**27**			60
Segment Income (Loss)			**$ 87**			$ (7)

Revenues in Midstream & Market Optimization operations increased 52 percent in the third quarter of 2005 compared with the same period in 2004 due primarily to increases in commodity prices. Operating cash flow increased to $13 million in this same period from $8 million in 2004 due to higher levels of third party gas storage activity and strong margins for NGLs.

Revenues increased 22 percent compared with 2004 on a year-to-date basis as a result of increased commodity prices. Year-to-date operating cash flow was $114 million, an increase of $61 million compared with 2004. Improved margins from gas storage optimization activities and NGLs contributed to most of this increase.

Year-to-date DD&A is $33 million lower than in 2004. In 2004, DD&A expenses increased approximately $35 million due to a writedown in the values of EnCana’s equity investment interest in the Trasandino Pipeline in Argentina and Chile.

CORPORATE

($ millions)	Three months ended September 30 2005	2005 vs 2004	2004	Nine months ended September 30 2005	2005 vs 2004	2004
Revenues	**$ (939)**	-118%	$ (430)	**$ (1,596)**	-86%	$ (857)
Expenses						
Operating	**(1)**	-200%	1	**(3)**	25%	(4)
Depreciation, depletion and amortization	**19**	36%	14	**54**	23%	44
Segment Loss	**$ (957)**	-115%	$ (445)	**$ (1,647)**	-84%	$ (897)
Administrative	**78**	81%	43	**205**	51%	136
Interest, net	**218**	106%	106	**419**	48%	284
Accretion of asset retirement obligation	**9**	29%	7	**27**	69%	16
Foreign exchange gain	**(213)**	27%	(290)	**(63)**	70%	(213)
Stock-based compensation	**4**	-20%	5	**12**	-14%	14
Gain on dispositions	**-**	-	-	**-**	100%	(35)

Year-to-date 2005 corporate revenues include approximately $1,596 million in unrealized mark-to-market losses related to financial commodity contracts compared with $859 million during the same period of 2004. Other mark-to-market gains ($3 million) on derivative financial instruments related to electricity consumption are recorded in operating expenses.

Summary of Unrealized Mark-to-Market Gains (Losses)

($ millions)	Three months ended September 30 2005	2004	Nine months ended September 30 2005	2004
Continuing Operations				
Natural Gas	**$ (990)**	$ (300)	**$ (1,564)**	$ (550)
Crude Oil	**51**	(129)	**(32)**	(309)
	(939)	(429)	**(1,596)**	(859)
Expenses	**(1)**	(2)	**(3)**	(7)
	(938)	(427)	**(1,593)**	(852)
Income Tax	**(307)**	(151)	**(535)**	(291)
	$ (631)	$ (276)	**$ (1,058)**	$ (561)

Price volatility has had a significant impact on the accounting for our price risk management activities. On September 30, 2005 the forward price curve for the fourth quarter of 2005 had increased from June 30, 2005 by 12 percent to $66.40 per bbl for WTI and 83 percent to $14.09 per Mcf for NYMEX gas.

DD&A includes provisions for corporate assets such as computer equipment, office furniture and leasehold improvements.

Administrative expenses increased $35 million in the third quarter and $69 million for the nine months ended September 30, 2005 compared to 2004. The increase reflects the effect of the increased long-term compensation expenses that are tied to EnCana's common share price and the change in the U.S./Canadian dollar exchange rate. On a year-to-date basis, administrative costs were approximately $0.18 per Mcfe compared with $0.13 per Mcfe in 2004.

Interest expense in the third quarter of 2005 and on a year-to-date basis has increased as a result of a $121 million ($79 million after-tax) charge to retire certain medium term notes and the higher average outstanding debt level compared with 2004. EnCana's long-term debt increased by $483 million to $8,225 million at September 30, 2005 compared with $7,742 million at December 31, 2004. EnCana's 2005 year-to-date weighted average interest rate on outstanding debt was 5.3 percent, up from a year-to-date average of approximately 4.9 percent in 2004 as a result of a reduction in the proportion of floating rate debt.

The foreign exchange gain of $63 million to-date in 2005 includes $140 million ($113 million after-tax) resulting from the change in the U.S./Canadian dollar exchange rate applied to U.S. dollar denominated debt issued from Canada. Under Canadian GAAP, the Company is required to translate long-term debt issued from Canada and denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting unrealized foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings.

INCOME TAX

The year-to-date effective tax rate was 27.5 percent compared with 12.1 percent in 2004. The 2005 effective tax rate is higher than 2004 primarily as a result of the reduction in 2004 of $109 million in future income taxes resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent and Alberta's retention of the resource allowance and non-deductible crown royalties regime until 2007. The 2005 income tax provision has been reduced by the net benefit of tax basis retained on dispositions of $68 million (2004: $162 million) as well as $535 million related to income tax on unrealized mark to market losses (2004: $291 million).

Included in net earnings for the nine months ended September 30, 2005 is current tax expense of $1,068 million; $591 million of this relates to the sale of assets and has been shown as an investing activity in the Statement of Cash Flows. The balance of $477 million has been included in cash flow.

Further information regarding EnCana's effective tax rate can be found in Note 6 to the Interim Consolidated Financial Statements. Income tax is an annual calculation and EnCana's effective rate in any year is a function of the relationship between the amount of net earnings before income taxes for the year and the magnitude of the items representing "permanent differences" that are excluded from the earnings subject to tax. There are a variety of items of this type, including:

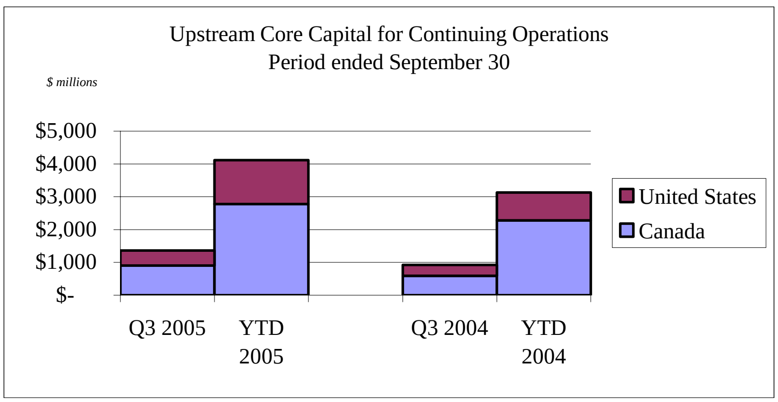
- The effects of asset dispositions where the tax values of the assets sold differ from their accounting values;
- Adjustments for the impact of legislative tax changes which have a prospective impact on future income tax obligations;
- The non-taxable half of Canadian capital gains (losses); and
- Items such as resource allowance and non-deductible crown payments where the income tax treatment is different from the accounting treatment.

The operations of the Company are complex and related tax interpretations, regulations and legislation in the various jurisdictions that the Company and its subsidiaries operate in are continually changing. As a result, there are usually some tax matters under review. The Company believes that the provision for taxes is adequate.

CAPITAL EXPENDITURES

Capital Summary

	Three months ended September 30			Nine months ended September 30		
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Upstream	**$ 1,390**	48%	$ 938	**$ 4,168**	31%	$ 3,182
Midstream & Market Optimization	**32**	113%	15	**172**	330%	40
Corporate	**34**	240%	10	**49**	75%	28
Core Capital Expenditures	**$ 1,456**	51%	$ 963	**$ 4,389**	35%	$ 3,250
Acquisitions	**200**		39	**238**		2,646
Dispositions	**(34)**		(940)	**(2,493)**		(1,612)
Discontinued Operations	**33**		145	**133**		584
Net Capital	**$ 1,655**		$ 207	**$ 2,267**		$ 4,868



UPSTREAM CAPITAL EXPENDITURES

The increase in Upstream capital expenditures in the third quarter and on a year-to-date basis in 2005 is the result of the impact of higher industry activity on drilling and completion costs and a higher average U.S./Canadian dollar exchange rate on Canadian dollar denominated expenditures. The change in the average U.S./Canadian dollar exchange rate resulted in an increase on Canadian dollar denominated core capital expenditures of approximately $189 million. Natural gas capital expenditures were focused on continued development of the Company's key resource plays in the Piceance basin, Jonah, East Texas and Fort Worth in the United States and Greater Sierra, Cutbank Ridge, shallow gas and CBM in Canada. Crude oil capital spending in 2005 was concentrated at Foster Creek and Pelican Lake in Alberta. The Company drilled 3,520 net wells in the first nine months of 2005 compared to 3,971 net wells for the same period in 2004. Record setting wet weather in Western Canada and high levels of industry activity in the North American oil and gas services sector has restricted access to land and equipment which has curtailed the drilling program, delayed well tie-ins and increased capital costs.

MIDSTREAM & MARKET OPTIMIZATION CAPITAL EXPENDITURES

Expenditures in the third quarter of 2005 and on a year-to-date basis were mostly focused on pre-construction activities underway for the Entrega pipeline in Colorado.

CORPORATE CAPITAL EXPENDITURES

Corporate capital expenditures have generally been focused on business information systems and leasehold improvements. The increase in spending in the third quarter of 2005 includes land purchased to build the Calgary office complex.

ACQUISITIONS AND DISPOSITIONS

Acquisitions included minor property acquisitions in 2005 and 2004 as well as the TBI acquisition in 2004.

Dispositions in 2005 include the sale of Gulf of Mexico assets and the sale of non-core Canadian conventional oil and gas assets. Dispositions in the first nine months of 2004 include the sale of Petrovera and the sale of non-core Canadian conventional oil and gas assets.

DISCONTINUED OPERATIONS

Discontinued operations in the Interim Consolidated Financial Statements include Ecuador in both 2005 and 2004 and also include the United Kingdom in 2004.

EnCana’s 2005 third quarter net earnings from discontinued operations are nil compared to a net loss of $39 million in 2004 and include realized commodity losses of $35 million after-tax (2004: $58 million after-tax) and unrealized financial hedge gains of $27 million after-tax (2004: losses of $45 million after-tax).

EnCana’s 2005 year-to-date net earnings from discontinued operations are $133 million compared to a net loss of $90 million in 2004 and include realized commodity hedge losses of $72 million after-tax (2004: $140 million after-tax) and unrealized financial hedge gains of $35 million after-tax (2004: losses of $116 million after-tax). Summary information is presented below. Additional information concerning EnCana’s discontinued operations can be found in Note 3 to EnCana’s Interim Consolidated Financial Statements.

ECUADOR

	Three months ended September 30			Nine months ended September 30		
	2005	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Sales volumes						
Crude Oil *(barrels per day)*	**68,710**	-8%	74,846	**71,443**	-8%	78,032
($ millions)						
Net Earnings (loss) from Discontinued Operations	**$ -**	100%	$ (29)	**$ 131**	279%	$ (73)
Capital Investment	**33**	-38%	53	**133**	-18%	163

In accordance with Canadian generally accepted accounting principles, DD&A expense has not been recorded in the consolidated statement of earnings for discontinued operations.

On September 13, 2005 EnCana announced it had reached an agreement to sell all its interest in its Ecuador properties for $1.42 billion which is approximately equivalent to the asset’s net book value at July 1, 2005, the referenced effective date of the transaction. Net earnings for the third quarter were $123 million. However, at September 30, a provision of $123 million has been recorded against the net book value to recognize management’s best estimate of the difference between the selling price and the September 30, 2005 underlying accounting value of the related investments at the sales date, as required under Canadian generally accepted accounting principles.

Production volumes in the third quarter of 2005 averaged 71,896 bbls/d; down six percent from the same period in 2004. Sales volumes in the third quarter of 2005 decreased eight percent to average 68,710 bbls/d due to declining production in Tarapoa and Block 15 as well as civil unrest and protests during August that resulted in the shutdown of production for a number of days.

Production and mineral taxes were $31 million higher in the third quarter of 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. The Company is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

Production volumes for the first nine months of 2005 averaged 73,737 bbls/d; down four percent from the same period in 2004. Sales volumes in the first nine months of 2005 decreased eight percent to average 71,443 bbls/d due to an underlift of 2,294 bbls/d in the first nine months of 2005 compared to an overlift of 946 bbls/d in the same period in 2004 combined with declining production in Tarapoa and Block 15. In addition, the civil unrest and protests in Ecuador in August 2005 resulted in a decrease in sales of 880 bbls/d on a year-to-date basis.

Production and mineral taxes were $59 million higher in the first nine months of 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes.

Contingency information regarding certain disputed items with the Ecuadorian government relating to value-added tax (“VAT”), ownership of Block 15 and deductibility of interest is included in Note 3 to EnCana's Interim Consolidated Financial Statements.

UNITED KINGDOM

	Three months ended September 30		Nine months ended September 30	
	2005	2004	**2005**	2004
Sales volumes				
Produced Gas *(million cubic feet per day)*	-	32	-	32
Crude Oil *(barrels per day)*	-	12,819	-	15,855
NGLs *(barrels per day)*	-	2,070	-	2,035
Total *(barrels of oil equivalent per day)*	-	20,222	-	23,223
($ millions)				
Net Earnings (loss) from Discontinued Operations	**$ -**	$ (10)	**$ 2**	$ (17)
Capital Investment	-	82	-	290

In December 2004, a subsidiary of the Company completed the sale of its U.K. central North Sea assets, production and prospects for net cash consideration of approximately $2.1 billion, resulting in a gain on sale of approximately $1.4 billion.

LIQUIDITY AND CAPITAL RESOURCES

	Three months ended September 30			Nine months ended September 30		
($ millions)	**2005**	2005 vs 2004	2004	**2005**	2005 vs 2004	2004
Net cash provided by (used in)						
Operating activities	**$ 1,210**	13%	$ 1,068	**$ 4,008**	21%	$ 3,303
Investing activities	**(2,011)**	-648%	(269)	**(2,781)**	44%	(4,954)
Financing activities	**626**	170%	(888)	**(1,681)**	-205%	1,598
Deduct: Foreign exchange gain on cash and cash equivalents held in foreign currency	**4**	-	-	**2**	-	-
(Decrease) increase in cash and cash equivalents	**(179)**	-101%	(89)	**(456)**	-760%	(53)

EnCana's cash flow from continuing operations was $1,823 million in the third quarter of 2005, up $564 million from $1,259 million for the same period in 2004. On a year-to-date basis, cash flow from continuing operations was $4,643 million, an increase of $1,467 million from 2004. The increase in cash flow in 2005 was primarily due to increased revenues from higher commodity prices and the growth in sales volumes partially offset by increased expenses. Cash flow from continuing operations comprises the majority of EnCana's cash provided by operating activities.

Net cash of $2,011 million was used for investing activities, an increase of $1,742 million compared with in the third quarter of 2004. The key items contributing to this increase are a $633 million increase in 2005 capital spending and decreased proceeds on the disposal of assets of $906 million. On a year-to-date basis, net cash used by investing activities was $2,781 million compared with $4,954 million in 2004.

Long-term debt plus the current portion of long-term debt increased by $514 million to $8,444 million from the year-end total of $7,930 million. EnCana's net debt adjusted for working capital was $9,248 million as at September 30, 2005 compared with $7,184 million at December 31, 2004. Working capital at September 30, 2005 was a deficit of $1,023 million and included unrealized losses on mark-to-market accounting for commodity hedges of $1,566 million and income tax payable of $169 million. This compares to working capital of $558 million as at December 31, 2004.

During the third quarter, the Company completed the redemption of nine issues of Canadian medium term notes: EnCana's 5.95% notes due October 1, 2007, 5.95% notes due June 2, 2008, 5.80% notes due June 19, 2008, 6.10% notes due June 1, 2009, 7.15% notes due December 17, 2009, 8.50% notes due March 15, 2011, 7.10% notes due October 11, 2011, 7.30% notes due September 2, 2014 and 5.50%/6.20% notes due June 23, 2028. The aggregate principal amount of the notes was C$1.15 billion. The notes were redeemed at a total cost of C$1.3 billion, including interest.

On August 31, 2005, EnCana filed a shelf prospectus for the offering in Canada from time to time of up to C$1 billion of debt securities. This shelf prospectus replaced EnCana's previous C$1 billion shelf prospectus which expired on September 20, 2005. On September 21, 2005, EnCana closed a public offering in Canada for C$500 million medium term notes due in 2008 at 3.60% under the new shelf prospectus. The proceeds of the offering were used primarily to repay existing bank and commercial paper indebtedness.

Financial Metrics

	September 30 2005	December 31 2004
Net Debt to Capitalization	**40%**	33%
Net Debt to EBITDA[1]	**1.6x**	1.4x

[1] EBITDA is a non-GAAP measure that is defined as earnings from continuing operations before gain on disposition, income taxes, foreign exchange gains or losses, gains or losses, interest net, acccretion of asset retirement obligation, and depreciation, depletion, and amortization.

Net Debt to Capitalization and Net Debt to EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength. Unrealized commodity hedge losses recorded in the first nine months of 2005 and the use of surplus cash to purchase shares through the Normal Course Issuer Bid have resulted in an increase in the net debt to capitalization ratio.

EnCana maintains investment grade credit ratings on its senior unsecured debt. Standard & Poor's has assigned a rating of A- with a 'Negative Outlook', Dominion Bond Rating Services has assigned a rating of A(low) with a 'Stable Trend' and Moody's has assigned a rating of 'Baa2 Stable'.

As at September 30, 2005, the Company had available unused committed bank credit facilities in the amount of $1.5 billion.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

EnCana's shareholders approved a split of the Corporation's outstanding Common Shares on a two-for-one basis ("Share Split") at its Annual and Special Meeting held on April 27, 2005. Each shareholder received one additional common share for each common share held on the record date of May 12, 2005.

(millions)	September 30 2005[1]	December 31 2004[1]
Outstanding, beginning of year	**900.6**	921.2
Issued under option plans	**13.9**	19.4
Shares purchased (Normal Course Issuer Bid)	**(55.2)**	(40.0)
Shares purchased (Performance Share Unit Plan)	**(5.5)**	-
Common shares outstanding, end of period	**853.8**	900.6
Weighted average common shares outstanding - diluted	**894.2**	936.0

[1] The number of common shares outstanding prior to the 2 for 1 share split has been restated for comparison.

There were no Preferred Shares outstanding during these periods. Employees and directors have been granted options to purchase Common Shares under various plans. At September 30, 2005, 21.9 million options, without Tandem Share Appreciation Rights attached, were outstanding of which 17.6 million are exercisable.

Long-term incentives granted to employees throughout EnCana include a reduced level of stock option grants that is supplemented by grants of Performance Share Units ("PSUs"). PSUs will not result in the issue of new Common Shares by the Company. Stock options granted in 2004 and 2005 have an associated Tandem Share Appreciation Right ("TSAR") and employees may elect to exercise either the stock option or the associated TSAR. TSAR exercises will result in either cash payments by the Company or issuance of Common Shares based upon the employee’s choice at the time of exercise.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under four consecutive Normal Course Issuer Bids which commenced in October 2002 and may continue until October 30, 2006. EnCana is entitled to purchase for cancellation up to approximately 85.6 million Common Shares under the renewed Bid which will commence on October 31, 2005 and will terminate not later than October 30, 2006. Under the prior Bid which commenced October 29, 2004 and expires October 28, 2005, EnCana purchased approximately 84.2 million Common Shares. Shareholders may obtain a copy of the Bid documents without charge at www.sedar.com or by contacting investor.relations@encana.com.

Normal Course Issuer Bid

	Share Purchases[1]	
(millions)	Nine months ended September 30 2005	Year ended December 31 2004
Bid expired October 2004	-	11.0
Bid expiring October 2005	**55.2**	29.0
	55.2	40.0

(1) Transactions that occurred before the 2 for 1 share split have been restated for comparison.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

Included in the Company’s long-term debt commitments of $8,379 million at September 30, 2005 are $2,942 million outstanding related to Banker’s Acceptances, Commercial Paper and LIBOR loans that are supported by revolving credit facilities and term loan borrowings. The Company intends and expects that it will have the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company’s long-term debt are described in Note 7 to the Interim Consolidated Financial Statements.

As at September 30, 2005, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 48 MMcf/d with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 154 Bcf at a weighted average price of $3.87 per Mcf. At September 30, 2005, these transactions had an unrealized loss of $449 million.

Contingency information regarding certain disputed items with the Ecuadorian government relating to VAT, ownership of Block 15 and deductibility of interest is included in Note 3 to EnCana's Interim Consolidated Financial Statements.

Variable Interest Entities ("VIE")
EnCana does not hold any interest in a VIE.

Off-Balance Sheet Arrangements
The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have an effect on its results of operations or financial condition.

Leases
As a normal course of business, the Company leases office space for personnel who support field operations and for corporate purposes.

Legal Proceedings Related to Discontinued Merchant Energy Operations
As previously described in the Company's Management Discussion and Analysis for the year ended December 31, 2004, 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") of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $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 multiple other lawsuits filed in California State and District Court (many of which are class actions). WD is a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The Gallo complaint claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

The California lawsuits relate to sales of natural gas in California from 1999 to 2002 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 consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices resulted in higher prices of natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to the Company as the remaining defendants. 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 or any future proceedings against the Company, 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 proceedings arising out of these allegations.

ACCOUNTING POLICIES AND ESTIMATES

There have been no changes to EnCana's accounting principles and practices in 2005, nor have there been any material changes to EnCana's critical accounting estimates.

RISK MANAGEMENT

EnCana's results are affected by

- financial risks (including commodity price, foreign exchange, interest rate and credit risks)
- operational risks
- environmental, health, safety and security risks
- reputational risks

FINANCIAL RISKS

The Company partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk, the Company has entered into various financial instrument agreements. The Company's policy is not to use derivative financial instruments for speculative purposes. The details of these instruments, including any unrealized gains or losses, as of September 30, 2005, are disclosed in Note 12 to the Interim Consolidated Financial Statements.

The Company has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of price risk associated with cash flows expected to be generated from budgeted capital programs and in other cases to the mitigation of price risks for specific assets and obligations.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by the Company are swaps, collars or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

Commodity Price

To partially mitigate the natural gas commodity price risk, the Company entered into swaps which fix the AECO and NYMEX prices and collars and put options which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, the Company has entered into swaps to fix the AECO and Rockies price differential from the NYMEX price. Physical contracts relating to these activities had an unrecognized gain of $61 million.

The Company has also entered into contracts to purchase and sell natural gas as part of its daily ongoing operations of the Company's proprietary production management. Physical contracts associated with this activity had an unrecognized gain of $8 million.

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

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for a portion of its oil production with fixed price swaps, purchased call options to allow participation at higher WTI levels, three-way put spreads and put options.

The Company has a power purchase arrangement contract that expires in 2005. This contract was entered into as part of a cost management strategy.

Foreign Exchange

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company may enter into foreign exchange contracts. The Company also enters into foreign exchange contracts in conjunction with crude oil marketing transactions. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined.

The Company also maintains a mix of both U.S. dollar and Canadian dollar debt which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company has entered into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rates

The Company partially mitigates its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. The Company has entered into interest rate swap transactions from time to time as a means of managing the fixed/floating rate debt portfolio mix.

Credit Risk

The Company is exposed to credit related losses in the event of default by counterparties. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions to counterparties of investment grade credit quality and transactions that are fully collateralized. A substantial portion of the Company's accounts receivable is with customers in the oil and gas industry.

OPERATIONAL RISKS

EnCana mitigates operational risk through a number of policies and processes. As part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of their previous capital program to identify key learnings, which often includes operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues which had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback results are analyzed for the Company's capital program with the results and identified learnings shared across the Company.

Projects include a Business Risk Burden that is intended to account for the unforeseen risks. The amount of Business Risk Burden that is used on a particular project depends on the project's history of Lookback results and the type of expenditure. A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

The Company also partially mitigates operational risks by maintaining a comprehensive insurance program.

ENVIRONMENT, HEALTH, SAFETY AND SECURITY RISKS

These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors recommends approval of environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

Security risks are managed through a Security Program designed to protect EnCana's personnel and assets. EnCana has established an Investigations Committee with the mandate to address potential violations of Company policies and practices and an Integrity Hotline that can be used to raise any concerns regarding EnCana's operations.

Kyoto Protocol

The Kyoto protocol, ratified by the Canadian Federal Government in December 2002, came into force on February 16, 2005. The protocol commits Canada to reducing greenhouse gas emissions to six percent below 1990 levels over the period 2008 – 2012. The Federal Government released a framework outlining its Climate Change action plan on April 13, 2005. The plan as released contains few technical details regarding the implementation of the Government's greenhouse gas reduction strategy. The Climate Change Working Group of Canadian Association of Petroleum Producers continues to work with the Federal and Alberta governments to develop an approach for implementing targets and enabling greenhouse gas control legislation which protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

As the federal government has yet to finalize their detailed Kyoto compliance plan, EnCana is unable to predict the impact of the potential regulations upon its business; however, it is possible that the Company would face increases in operating costs in order to comply with greenhouse gas emissions legislation.

REPUTATIONAL RISKS

EnCana takes a pro-active approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear procedures, guidelines and responsibility for identifying and managing these issues. Issues affecting or with the potential to affect EnCana's reputation are generally either emerging issues that can be identified early and then managed or unforeseen issues that arise unexpectedly and must be managed on an urgent basis.

OUTLOOK

EnCana plans to continue to focus principally on growing natural gas production from unconventional resource plays. The Company will also continue to develop its high quality in-situ oilsands resources.

The year-over-year North American natural gas storage surplus that existed at the start of the third quarter has been turned into a deficit as a result of demand due to the hottest summer on record and supply curtailments from hurricanes Rita and Katrina. This has led to recent price increases. The outlook for the balance of the year and beyond will be especially impacted by weather in the short term, timing of new supplies and economic activity.

Volatility in crude oil prices is expected to continue throughout 2005 as a result of market uncertainties over supply and refining disruptions on the U.S. Gulf Coast, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies.

The Company expects its 2005 core capital investment program to be funded from cash flow.

Proceeds from the sales of non-core properties are expected to reduce debt and fund a Normal Course Issuer Bid share buyback program.

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas, as well as movements in foreign currency exchange rates.

ADVISORIES

FORWARD-LOOKING STATEMENTS

In the interest of providing EnCana shareholders and potential investors with information regarding the Company and its subsidiaries, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this MD&A constitute forward-looking statements within the meaning of the "safe harbour" provisions 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: projections with respect to growth of natural gas production from unconventional resource plays and in-situ oilsands development; projections relating to the volatility of crude oil prices in 2005 and beyond and the reasons therefor; the Company's projected capital investment levels for 2005 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments; the Company's execution of share purchases under its Normal Course Issuer Bid; the Company's defence of lawsuits; the impact of the Kyoto Accord on operating costs; the adequacy of the Company's provision for taxes; the Company's plans to divest of its NGLs extraction business, natural gas storage business and Ecuador operations; and projections relating to the use of proceeds therefrom, including debt repayment and purchases under its Normal Course Issuer Bid. 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 and its subsidiaries' 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; the Company's and its subsidiaries' 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; the Company's ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's and its subsidiaries' ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the Company and its subsidiaries operate, including Ecuador; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company and its subsidiaries operate and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company and its subsidiaries; 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" or "resource potential" 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.

OIL AND GAS INFORMATION

EnCana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to EnCana by Canadian securities regulatory authorities which permits it to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by EnCana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (“NI 51-101”). The reserves quantities disclosed by EnCana represent net proved reserves calculated using the standards contained in Regulation S-X of the U.S. Securities and Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in EnCana's Annual Information Form.

Crude Oil, Natural Gas Liquids and Natural Gas Conversions

In this MD&A, certain crude oil and natural gas liquids (“NGLs”) volumes have been converted to millions of cubic feet equivalent (“MMcfe”) or thousands of cubic feet equivalent (“Mcfe”) on the basis of one barrel (“bbl”) to six thousand cubic feet (“Mcf”). Also, certain natural gas volumes have been converted to barrels of oil equivalent (“BOE”), thousands of BOE ("MBOE") or millions of BOE (“MMBOE”) on the same basis. MMcfe, Mcfe, BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the well head.

Resource Play, Estimated Ultimate Recovery, Unbooked Resource Potential, Total Resource Portfolio and Total Resource Life

EnCana uses the terms resource play, estimated ultimate recovery, unbooked resource potential, total resource portfolio and total resource life. Resource play is a term used by EnCana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by EnCana, estimated ultimate recovery (”EUR”) has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom. EnCana defines unbooked Resource Potential as quantities of oil and gas on existing land holdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future.

CURRENCY, NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Interim Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after-royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.81 for every Canadian dollar.

Non-GAAP Measures

Certain measures in this MD&A do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles (“Canadian GAAP”) such as Cash Flow from Continuing Operations, Cash Flow, Cash Flow per share-diluted, Operating Earnings and Operating Earnings per share-diluted, Operating Earnings from Continuing Operations and EBITDA and therefore are considered non-GAAP measures. Therefore, these measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company’s liquidity and its ability to generate funds to finance its operations. Management’s use of these measures has been disclosed further in this MD&A as these measures are discussed and presented.

References To EnCana

For convenience, references in this MD&A to “EnCana”, the “Company”, “we”, “us” and “our” may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (“Subsidiaries”) of EnCana Corporation, and the assets, activities and initiatives of such Subsidiaries.

ADDITIONAL INFORMATION

Further information regarding EnCana Corporation can be accessed under the Company’s public filings found at www.sedar.com and on the Company’s website at www.encana.com.

CONSOLIDATED STATEMENT OF EARNINGS *(unaudited)*

($ millions, except per share amounts)		Three Months Ended September 30, **2005**	2004	Nine Months Ended September 30, **2005**	2004
REVENUES, NET OF ROYALTIES	*(Note 2)*				
Upstream		**$ 2,680**	$ 1,861	**$ 7,013**	$ 5,253
Midstream & Market Optimization		**1,348**	889	**3,914**	3,206
Corporate - Unrealized (loss) on risk management		**(939)**	(430)	**(1,596)**	(859)
- Other		**-**	-	**-**	2
		3,089	2,320	**9,331**	7,602
EXPENSES	*(Note 2)*				
Production and mineral taxes		**107**	79	**291**	216
Transportation and selling		**139**	118	**406**	390
Operating		**432**	340	**1,177**	960
Purchased product		**1,244**	800	**3,540**	2,909
Depreciation, depletion and amortization		**677**	605	**2,038**	1,761
Administrative		**78**	43	**205**	136
Interest, net		**218**	106	**419**	284
Accretion of asset retirement obligation	*(Note 8)*	**9**	7	**27**	16
Foreign exchange (gain)	*(Note 5)*	**(213)**	(290)	**(63)**	(213)
Stock-based compensation		**4**	5	**12**	14
(Gain) on divestitures	*(Note 4)*	**-**	-	**-**	(35)
		2,695	1,813	**8,052**	6,438
NET EARNINGS BEFORE INCOME TAX		**394**	507	**1,279**	1,164
Income tax expense	*(Note 6)*	**128**	75	**352**	141
NET EARNINGS FROM CONTINUING OPERATIONS		**266**	432	**927**	1,023
NET EARNINGS (LOSS) FROM DISCONTINUED OPERATIONS	*(Note 3)*	**-**	(39)	**133**	(90)
NET EARNINGS		**$ 266**	$ 393	**$ 1,060**	$ 933
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 11)*				
Basic		**$ 0.31**	$ 0.47	**$ 1.06**	$ 1.11
Diluted		**$ 0.30**	$ 0.46	**$ 1.04**	$ 1.10
NET EARNINGS PER COMMON SHARE	*(Note 11)*				
Basic		**$ 0.31**	$ 0.43	**$ 1.21**	$ 1.01
Diluted		**$ 0.30**	$ 0.42	**$ 1.19**	$ 1.00

CONSOLIDATED STATEMENT OF RETAINED EARNINGS *(unaudited)*

($ millions)		Nine Months Ended September 30, **2005**	2004
RETAINED EARNINGS, BEGINNING OF YEAR		**$ 7,935**	$ 5,276
Net Earnings		**1,060**	933
Dividends on Common Shares		**(174)**	(137)
Charges for Normal Course Issuer Bid	*(Note 9)*	**(1,495)**	(126)
Charges for Shares Repurchased and Held	*(Note 9)*	**(147)**	-
RETAINED EARNINGS, END OF PERIOD		**$ 7,179**	$ 5,946

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET *(unaudited)*

($ millions)		**As at September 30, 2005**	As at December 31, 2004
ASSETS			
Current Assets			
Cash and cash equivalents		**$ 146**	$ 602
Accounts receivable and accrued revenues		**2,843**	1,898
Risk management	*(Note 12)*	**432**	336
Inventories		**680**	513
Assets of discontinued operations	*(Note 3)*	**309**	156
		4,410	3,505
Property, Plant and Equipment, net	*(Note 2)*	**23,891**	23,140
Investments and Other Assets		**461**	334
Risk Management	*(Note 12)*	**316**	87
Assets of Discontinued Operations	*(Note 3)*	**1,674**	1,623
Goodwill		**2,599**	2,524
	(Note 2)	**$ 33,351**	$ 31,213
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 2,460**	$ 1,879
Income tax payable		**475**	359
Risk management	*(Note 12)*	**1,948**	241
Liabilities of discontinued operations	*(Note 3)*	**331**	280
Current portion of long-term debt	*(Note 7)*	**219**	188
		5,433	2,947
Long-Term Debt	*(Note 7)*	**8,225**	7,742
Other Liabilities		**116**	118
Risk Management	*(Note 12)*	**308**	192
Asset Retirement Obligation	*(Note 8)*	**674**	611
Liabilities of Discontinued Operations	*(Note 3)*	**177**	102
Future Income Taxes		**4,615**	5,193
		19,548	16,905
Shareholders' Equity			
Share capital	*(Note 9)*	**5,107**	5,299
Share options, net		**-**	10
Paid in surplus		**110**	28
Retained earnings		**7,179**	7,935
Foreign currency translation adjustment		**1,407**	1,036
		13,803	14,308
		$ 33,351	$ 31,213

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS *(unaudited)*

($ millions)		Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
OPERATING ACTIVITIES					
Net earnings from continuing operations		**$ 266**	$ 432	**$ 927**	$ 1,023
Depreciation, depletion and amortization		**677**	605	**2,038**	1,761
Future income taxes	*(Note 6)*	**(41)**	(28)	**(716)**	(370)
Cash tax on sale of assets	*(Note 4)*	**-**	-	**591**	-
Unrealized loss on risk management	*(Note 12)*	**938**	426	**1,593**	852
Unrealized foreign exchange (gain)		**(202)**	(193)	**(79)**	(122)
Accretion of asset retirement obligation	*(Note 8)*	**9**	7	**27**	16
(Gain) on divestitures	*(Note 4)*	**-**	-	**-**	(35)
Other		**176**	10	**262**	51
Cash flow from continuing operations		**1,823**	1,259	**4,643**	3,176
Cash flow from discontinued operations		**108**	104	**273**	313
Cash flow		**1,931**	1,363	**4,916**	3,489
Net change in other assets and liabilities		**(160)**	(25)	**(174)**	(71)
Net change in non-cash working capital from continuing operations		**(543)**	(387)	**(659)**	(402)
Net change in non-cash working capital from discontinued operations		**(18)**	117	**(75)**	287
		1,210	1,068	**4,008**	3,303
INVESTING ACTIVITIES					
Business combination with Tom Brown, Inc.		**-**	-	**-**	(2,335)
Capital expenditures	*(Note 2)*	**(1,635)**	(1,002)	**(4,606)**	(3,308)
Proceeds on disposal of assets	*(Note 4)*	**34**	940	**2,493**	1,359
Cash tax on sale of assets	*(Note 4)*	**-**	-	**(591)**	-
Equity investments		**-**	8	**-**	52
Net change in investments and other		**35**	(8)	**27**	(25)
Net change in non-cash working capital from continuing operations		**(355)**	14	**93**	(98)
Discontinued operations		**(90)**	(221)	**(197)**	(599)
		(2,011)	(269)	**(2,781)**	(4,954)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		**1,691**	(662)	**976**	(215)
Issuance of long-term debt		**428**	1,000	**428**	3,761
Repayment of long-term debt		**(958)**	(1,205)	**(959)**	(1,754)
Issuance of common shares	*(Note 9)*	**86**	30	**270**	184
Purchase of common shares	*(Note 9)*	**(452)**	-	**(2,114)**	(230)
Dividends on common shares		**(64)**	(45)	**(174)**	(137)
Other		**(105)**	(6)	**(108)**	(11)
		626	(888)	**(1,681)**	1,598
DEDUCT: FOREIGN EXCHANGE GAIN ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		**4**	-	**2**	-
DECREASE IN CASH AND CASH EQUIVALENTS		**(179)**	(89)	**(456)**	(53)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		**325**	149	**602**	113
CASH AND CASH EQUIVALENTS, END OF PERIOD		**$ 146**	$ 60	**$ 146**	$ 60

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries ("EnCana" or the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration for, and production and marketing of, natural gas, crude oil and natural gas liquids, as well as natural gas storage, 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, 2004. 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, 2004.

2. SEGMENTED INFORMATION

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

- **Upstream** includes the Company's exploration for, and development and production of, natural gas, crude oil and natural gas liquids and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States. Frontier and international new venture exploration is mainly focused on opportunities in Africa, South America, the Middle East and Greenland.

- **Midstream & Market Optimization** is conducted by the Midstream & Marketing division. Midstream includes natural gas storage, natural gas liquids processing and power generation. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Midstream & Market Optimization segment.

- **Corporate** includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

Midstream & Market Optimization purchases substantially all of the Company's North American Upstream production. Transactions between business segments are based on market values and eliminated on consolidation. The tables in this note present financial information on an after eliminations basis.

Operations that have been discontinued are disclosed in Note 3.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Market Optimization	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 2,680**	$ 1,861	**$ 1,348**	$ 889
Expenses				
Production and mineral taxes	**107**	79	**-**	-
Transportation and selling	**133**	114	**6**	4
Operating	**348**	262	**85**	77
Purchased product	**-**	-	**1,244**	800
Depreciation, depletion and amortization	**649**	583	**9**	8
Segment Income	**$ 1,443**	$ 823	**$ 4**	$ -

	Corporate *		Consolidated	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ (939)**	$ (430)	**$ 3,089**	$ 2,320
Expenses				
Production and mineral taxes	**-**	-	**107**	79
Transportation and selling	**-**	-	**139**	118
Operating	**(1)**	1	**432**	340
Purchased product	**-**	-	**1,244**	800
Depreciation, depletion and amortization	**19**	14	**677**	605
Segment Income (Loss)	**$ (957)**	$ (445)	**490**	378
Administrative			**78**	43
Interest, net			**218**	106
Accretion of asset retirement obligation			**9**	7
Foreign exchange gain			**(213)**	(290)
Stock-based compensation			**4**	5
Gain on divestitures			**-**	-
			96	(129)
Net Earnings Before Income Tax			**394**	507
Income tax expense			**128**	75
Net Earnings From Continuing Operations			**$ 266**	$ 432

* For the three months ended September 30, the unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see also Note 12):

	2005	2004
Revenues, Net of Royalties - Corporate	**$ (939)**	$ (429)
Operating Expenses and Other - Corporate	**(1)**	1
Total Unrealized Loss on Risk Management - Continuing Operations	**$ (938)**	$ (430)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Upstream	Canada		United States	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 1,807**	$ 1,283	**$ 797**	$ 512
Expenses				
Production and mineral taxes	**24**	23	**83**	56
Transportation and selling	**84**	91	**49**	23
Operating	**207**	170	**56**	32
Depreciation, depletion and amortization	**485**	445	**157**	131
Segment Income	**$ 1,007**	$ 554	**$ 452**	$ 270

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 76**	$ 66	**$ 2,680**	$ 1,861
Expenses				
Production and mineral taxes	**-**	-	**107**	79
Transportation and selling	**-**	-	**133**	114
Operating	**85**	60	**348**	262
Depreciation, depletion and amortization	**7**	7	**649**	583
Segment Income (Loss)	**$ (16)**	$ (1)	**$ 1,443**	$ 823

Midstream & Market Optimization	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2005	2004	**2005**	2004	**2005**	2004
Revenues	**$ 195**	$ 158	**$ 1,153**	$ 731	**$ 1,348**	$ 889
Expenses						
Transportation and selling	**-**	-	**6**	4	**6**	4
Operating	**67**	65	**18**	12	**85**	77
Purchased product	**115**	88	**1,129**	712	**1,244**	800
Depreciation, depletion and amortization	**8**	8	**1**	-	**9**	8
Segment Income (Loss)	**$ 5**	$ (3)	**$ (1)**	$ 3	**$ 4**	$ -

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Produced Gas

	Produced Gas					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 1,317**	$ 970	**$ 726**	$ 462	**$ 2,043**	$ 1,432
Expenses						
Production and mineral taxes	**19**	18	**77**	51	**96**	69
Transportation and selling	**70**	72	**49**	23	**119**	95
Operating	**134**	99	**56**	32	**190**	131
Operating Cash Flow	**$ 1,094**	$ 781	**$ 544**	$ 356	**$ 1,638**	$ 1,137

Oil & NGLs

	Oil & NGLs					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 490**	$ 313	**$ 71**	$ 50	**$ 561**	$ 363
Expenses						
Production and mineral taxes	**5**	5	**6**	5	**11**	10
Transportation and selling	**14**	19	**-**	-	**14**	19
Operating	**73**	71	**-**	-	**73**	71
Operating Cash Flow	**$ 398**	$ 218	**$ 65**	$ 45	**$ 463**	$ 263

Other & Total Upstream

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 76**	$ 66	**$ 2,680**	$ 1,861
Expenses				
Production and mineral taxes	**-**	-	**107**	79
Transportation and selling	**-**	-	**133**	114
Operating	**85**	60	**348**	262
Operating Cash Flow	**$ (9)**	$ 6	**$ 2,092**	$ 1,406

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

	Upstream		Midstream & Market Optimization	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 7,013**	$ 5,253	**$ 3,914**	$ 3,206
Expenses				
Production and mineral taxes	**291**	216	**-**	-
Transportation and selling	**390**	370	**16**	20
Operating	**936**	740	**244**	224
Purchased product	**-**	-	**3,540**	2,909
Depreciation, depletion and amortization	**1,957**	1,657	**27**	60
Segment Income (Loss)	**$ 3,439**	$ 2,270	**$ 87**	$ (7)

	Corporate *		Consolidated	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ (1,596)**	$ (857)	**$ 9,331**	$ 7,602
Expenses				
Production and mineral taxes	**-**	-	**291**	216
Transportation and selling	**-**	-	**406**	390
Operating	**(3)**	(4)	**1,177**	960
Purchased product	**-**	-	**3,540**	2,909
Depreciation, depletion and amortization	**54**	44	**2,038**	1,761
Segment Income (Loss)	**$ (1,647)**	$ (897)	**1,879**	1,366
Administrative			**205**	136
Interest, net			**419**	284
Accretion of asset retirement obligation			**27**	16
Foreign exchange gain			**(63)**	(213)
Stock-based compensation			**12**	14
Gain on divestitures			**-**	(35)
			600	202
Net Earnings Before Income Tax			**1,279**	1,164
Income tax expense			**352**	141
Net Earnings From Continuing Operations			**$ 927**	$ 1,023

* For the nine months ended September 30, the unrealized loss on risk management is recorded in the Consolidated Statement of Earnings as follows (see also Note 12):

	2005	2004
Revenues, Net of Royalties - Corporate	**$ (1,596)**	$ (859)
Operating Expenses and Other - Corporate	**(3)**	(4)
Total Unrealized Loss on Risk Management - Continuing Operations	**$ (1,593)**	$ (855)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Upstream	Canada		United States	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 4,747**	$ 3,770	**$ 2,071**	$ 1,313
Expenses				
Production and mineral taxes	**75**	61	**216**	155
Transportation and selling	**256**	277	**134**	93
Operating	**599**	505	**148**	80
Depreciation, depletion and amortization	**1,416**	1,296	**516**	330
Segment Income	**$ 2,401**	$ 1,631	**$ 1,057**	$ 655

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 195**	$ 170	**$ 7,013**	$ 5,253
Expenses				
Production and mineral taxes	**-**	-	**291**	216
Transportation and selling	**-**	-	**390**	370
Operating	**189**	155	**936**	740
Depreciation, depletion and amortization	**25**	31	**1,957**	1,657
Segment Income (Loss)	**$ (19)**	$ (16)	**$ 3,439**	$ 2,270

Midstream & Market Optimization	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2005	2004	**2005**	2004	**2005**	2004
Revenues	**$ 930**	$ 881	**$ 2,984**	$ 2,325	**$ 3,914**	$ 3,206
Expenses						
Transportation and selling	**-**	-	**16**	20	**16**	20
Operating	**204**	192	**40**	32	**244**	224
Purchased product	**630**	655	**2,910**	2,254	**3,540**	2,909
Depreciation, depletion and amortization	**26**	58	**1**	2	**27**	60
Segment Income (Loss)	**$ 70**	$ (24)	**$ 17**	$ 17	**$ 87**	$ (7)

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

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

Produced Gas

	Produced Gas					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 3,634**	$ 2,887	**$ 1,891**	$ 1,198	**$ 5,525**	$ 4,085
Expenses						
Production and mineral taxes	**56**	46	**198**	142	**254**	188
Transportation and selling	**211**	222	**134**	93	**345**	315
Operating	**377**	297	**148**	80	**525**	377
Operating Cash Flow	**$ 2,990**	$ 2,322	**$ 1,411**	$ 883	**$ 4,401**	$ 3,205

Oil & NGLs

	Oil & NGLs					
	Canada		United States		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 1,113**	$ 883	**$ 180**	$ 115	**$ 1,293**	$ 998
Expenses						
Production and mineral taxes	**19**	15	**18**	13	**37**	28
Transportation and selling	**45**	55	**-**	-	**45**	55
Operating	**222**	208	**-**	-	**222**	208
Operating Cash Flow	**$ 827**	$ 605	**$ 162**	$ 102	**$ 989**	$ 707

Other & Total Upstream

	Other		Total Upstream	
	2005	2004	**2005**	2004
Revenues, Net of Royalties	**$ 195**	$ 170	**$ 7,013**	$ 5,253
Expenses				
Production and mineral taxes	**-**	-	**291**	216
Transportation and selling	**-**	-	**390**	370
Operating	**189**	155	**936**	740
Operating Cash Flow	**$ 6**	$ 15	**$ 5,396**	$ 3,927

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. SEGMENTED INFORMATION (continued)

Capital Expenditures (Continuing Operations)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	**2005**	2004
Upstream				
Canada	**$ 912**	$ 634	**$ 2,806**	$ 2,337
United States	**647**	328	**1,540**	854
Other Countries	**10**	15	**39**	49
	1,569	977	**4,385**	3,240
Midstream & Market Optimization	**32**	15	**172**	40
Corporate	**34**	10	**49**	28
Total	**$ 1,635**	$ 1,002	**$ 4,606**	$ 3,308

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment As at		Total Assets As at	
		September 30, 2005	December 31, 2004	**September 30, 2005**	December 31, 2004
Upstream		**$ 22,670**	$ 22,097	**$ 27,640**	$ 26,118
Midstream & Market Optimization		**971**	804	**2,449**	1,904
Corporate		**250**	239	**1,279**	1,412
Assets of Discontinued Operations	*(Note 3)*			**1,983**	1,779
Total		**$ 23,891**	$ 23,140	**$ 33,351**	$ 31,213

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. DISCONTINUED OPERATIONS

Ecuador

At December 31, 2004, EnCana decided to divest of its Ecuador operations and such operations have been accounted for as discontinued operations. EnCana's Ecuador operations include the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in Block 15 and the 36.3 percent indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd. ("OCP"), which is the owner of a crude oil pipeline in Ecuador that ships crude oil from the producing areas of Ecuador to an export marine terminal. The Company is a shipper on the OCP Pipeline and pays commercial rates for tariffs. The majority of the Company's crude oil produced in Ecuador is sold to a single marketing company. Payments are secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

In accordance with Canadian generally accepted accounting principles, depletion, depreciation and amortization expense has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

On September 13, 2005, EnCana announced it had reached an agreement to sell all its interest in its Ecuador properties for $1.42 billion, which is approximately equivalent to the asset's net book value at July 1, 2005, the referenced effective date of the transaction. Net earnings for the third quarter were $123 million. However, at September 30, 2005, a provision of $123 million has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the September 30, 2005 underlying accounting value of the related investments at the sales date, as required under Canadian generally accepted accounting principles.

United Kingdom

On December 1, 2004, the Company completed the sale of its 100 percent interest in EnCana (U.K.) Limited for net cash consideration of approximately $2.1 billion. EnCana's U.K. operations included crude oil and natural gas interests in the U.K. central North Sea including the Buzzard, Scott and Telford oil fields, as well as other satellite discoveries and exploration licenses. A gain on sale of approximately $1.4 billion was recorded. Accordingly, these operations have been accounted for as discontinued operations.

Consolidated Statement of Earnings

The following table presents the effect of the discontinued operations in the Consolidated Statement of Earnings:

	For the three months ended September 30,					
	Ecuador		United Kingdom		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties	**$ 291**	$ 108	**$ -**	$ 30	**$ 291**	$ 138
Expenses						
Production and mineral taxes	**49**	18	**-**	-	**49**	18
Transportation and selling	**15**	16	**-**	10	**15**	26
Operating	**38**	30	**-**	12	**38**	42
Depreciation, depletion and amortization	**123**	63	**-**	26	**123**	89
Interest, net	**-**	-	**-**	(3)	**-**	(3)
Accretion of asset retirement obligation	**-**	-	**-**	1	**-**	1
Foreign exchange loss (gain)	**(1)**	1	**-**	1	**(1)**	2
	224	128	**-**	47	**224**	175
Net Earnings (Loss) Before Income Tax	**67**	(20)	**-**	(17)	**67**	(37)
Income tax expense (recovery)	**67**	9	**-**	(7)	**67**	2
Net Loss From Discontinued Operations	**$ -**	$ (29)	**$ -**	$ (10)	**$ -**	$ (39)

	For the nine months ended September 30,					
	Ecuador		United Kingdom		Total	
	2005	2004	**2005**	2004	**2005**	2004
Revenues, Net of Royalties *	**$ 723**	$ 298	**$ -**	$ 126	**$ 723**	$ 424
Expenses						
Production and mineral taxes	**101**	42	**-**	-	**101**	42
Transportation and selling	**46**	49	**-**	29	**46**	78
Operating	**100**	89	**-**	32	**100**	121
Depreciation, depletion and amortization	**123**	197	**-**	93	**123**	290
Interest, net	**-**	(1)	**-**	(5)	**-**	(6)
Accretion of asset retirement obligation	**1**	1	**-**	3	**1**	4
Foreign exchange loss (gain)	**-**	1	**(3)**	3	**(3)**	4
	371	378	**(3)**	155	**368**	533
Net Earnings (Loss) Before Income Tax	**352**	(80)	**3**	(29)	**355**	(109)
Income tax expense (recovery)	**221**	(7)	**1**	(12)	**222**	(19)
Net Earnings (Loss) From Discontinued Operations	**$ 131**	$ (73)	**$ 2**	$ (17)	**$ 133**	$ (90)

* Revenues, net of royalties in Ecuador include $105 million of realized losses (2004 - $171 million) and $50 million of unrealized gains (2004 - $134 million of losses) related to derivative financial instruments.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. DISCONTINUED OPERATIONS (continued)

Consolidated Balance Sheet

The impact of the discontinued operations in the Consolidated Balance Sheet is as follows:

	As at						
	September 30, 2005			December 31, 2004			
	Ecuador	United Kingdom	Total	Ecuador	United Kingdom	Syncrude	Total
Assets							
Cash and cash equivalents	**$ 123**	**$ 5**	**$ 128**	$ 2	$ 12	$ -	$ 14
Accounts receivable and accrued revenues	**159**	**-**	**159**	111	13	-	124
Risk management	**-**	**-**	**-**	3	-	-	3
Inventories	**22**	**-**	**22**	15	-	-	15
	304	**5**	**309**	131	25	-	156
Property, plant and equipment, net	**1,317**	**-**	**1,317**	1,295	-	-	1,295
Investments and other assets	**357**	**-**	**357**	328	-	-	328
	$ 1,978	**$ 5**	**$ 1,983**	$ 1,754	$ 25	$ -	$ 1,779
Liabilities							
Accounts payable and accrued liabilities	**$ 124**	**$ 29**	**$ 153**	$ 61	$ 32	$ 3	$ 96
Income tax payable	**153**	**3**	**156**	101	-	-	101
Risk management	**22**	**-**	**22**	72	-	-	72
	299	**32**	**331**	234	32	3	269
Asset retirement obligation	**23**	**-**	**23**	22	-	-	22
Future income taxes	**153**	**1**	**154**	80	11	-	91
	475	**33**	**508**	336	43	3	382
Net Assets of Discontinued Operations	**$ 1,503**	**$ (28)**	**$ 1,475**	$ 1,418	$ (18)	$ (3)	$ 1,397

Contingencies

In Ecuador, a subsidiary of EnCana has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. In its 2004 filings with Securities regulatory authorities, Occidental Petroleum Corporation indicated that its subsidiary had received formal notification from Petroecuador, the state oil company of Ecuador, initiating proceedings to determine if the subsidiary had violated the Hydrocarbons Law and its Participation Contract for Block 15 with Petroecuador and whether such violations constitute grounds for terminating the Participation Contract.

In its filings, Occidental Petroleum Corporation indicated that it believes it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

In addition to the above, the Company continues to proceed with its arbitration related to value-added tax ("VAT") owed to the Company and has been in discussions related to certain income tax matters related to interest deductibility and other matters in Ecuador.

4. DIVESTITURES

Total proceeds received on sale of assets and investments was $2,493 million (2004 - $1,359 million) as described below:

Upstream

In 2005, the Company has completed the disposition of mature conventional oil and natural gas assets for proceeds of $440 million (2004 - $1,358 million).

In May, the Company completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $591 million in tax plus other adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

Other

In March 2004, the Company sold its equity investment in a well servicing company for approximately $44 million, recording a pre-tax gain of $34 million.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

5. FOREIGN EXCHANGE (GAIN)

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Unrealized Foreign Exchange Gains on Translation of U.S. Dollar Debt Issued in Canada	**$ (205)**	$ (193)	**$ (140)**	$ (122)
Other Foreign Exchange (Gain) Loss	**(8)**	(97)	**77**	(91)
	$ (213)	$ (290)	**$ (63)**	$ (213)

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Current				
Canada	**$ 20**	$ 103	**$ 330**	$ 505
United States	**153**	3	**744**	18
Other	**(4)**	(3)	**(6)**	(12)
Total Current Tax	**169**	103	**1,068**	511
Future	**(41)**	(28)	**(716)**	(261)
Future Tax Rate Reductions	**-**	-	**-**	(109)
Total Future Tax	**(41)**	(28)	**(716)**	(370)
	$ 128	$ 75	**$ 352**	$ 141

The following table reconciles income taxes calculated at the Canadian statutory rate with the actual income taxes:

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2004	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2004
Net Earnings Before Income Tax	**$ 394**	$ 507	**$ 1,279**	$ 1,164
Canadian Statutory Rate	**37.9%**	39.1%	**37.9%**	39.1%
Expected Income Tax	**150**	198	**485**	455
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	**53**	51	**139**	154
Canadian resource allowance	**(51)**	(63)	**(141)**	(186)
Canadian resource allowance on unrealized risk management losses	**13**	8	**26**	27
Statutory and other rate differences	**(25)**	(17)	**(109)**	(47)
Effect of tax rate changes	**-**	-	**-**	(109)
Non-taxable capital gains	**(43)**	(55)	**(27)**	(41)
Previously unrecognized capital losses (gains)	**-**	(5)	**-**	10
Tax basis retained on dispositions	**-**	(59)	**(68)**	(162)
Large corporations tax	**20**	6	**24**	13
Other	**11**	11	**23**	27
	$ 128	$ 75	**$ 352**	$ 141
Effective Tax Rate	**32.5%**	14.8%	**27.5%**	12.1%

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

7. LONG-TERM DEBT

	As at September 30, 2005	As at December 31, 2004
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	**$ 2,166**	$ 1,515
Unsecured notes	**797**	1,309
	2,963	2,824
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	**776**	399
Unsecured notes and debentures	**4,640**	4,641
	5,416	5,040
Increase in Value of Debt Acquired *	**65**	66
Current Portion of Long-Term Debt	**(219)**	(188)
	$ 8,225	$ 7,742

* Certain of the notes and debentures of EnCana were acquired in business combinations and were accounted for at their fair value at the dates 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 22 years.

During the third quarter, EnCana redeemed a number of unsecured notes with a total principal of C$1,150 million. On September 21, 2005, EnCana completed a public offering of unsecured notes in the aggregate principal amount of C$500 million which bear interest at 3.60% and mature on September 15, 2008.

8. ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

	As at September 30, 2005	As at December 31, 2004
Asset Retirement Obligation, Beginning of Year	**$ 611**	$ 383
Liabilities Incurred	**60**	98
Liabilities Settled	**(29)**	(16)
Liabilities Disposed	**(23)**	(35)
Change in Estimated Future Cash Flows	**4**	124
Accretion Expense	**27**	22
Other	**24**	35
Asset Retirement Obligation, End of Period	**$ 674**	$ 611

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. SHARE CAPITAL

(millions)	**September 30, 2005** Number	Amount	December 31, 2004 Number	Amount
Common Shares Outstanding, Beginning of Year	**900.6**	**$ 5,299**	921.2	$ 5,305
Shares Issued under Option Plans	**13.9**	**270**	19.4	281
Shares Repurchased	**(60.7)**	**(462)**	(40.0)	(287)
Common Shares Outstanding, End of Period	**853.8**	**$ 5,107**	900.6	$ 5,299

Information related to common shares and stock options has been restated to reflect the effect of the common share split approved in April 2005.

Normal Course Issuer Bid

To September 30, 2005, the Company purchased 60,757,198 Common Shares for total consideration of approximately $2,114 million. Of the amount paid, $462 million was charged to Share capital, $10 million was charged to Paid in surplus and $1,642 million was charged to Retained earnings. Included in the above are 5.5 million Common Shares which have been purchased by a wholly owned Trust and are held for issuance upon vesting of units under EnCana's Performance Share Unit plan (see Note 10).

On October 26, 2004, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 29, 2004. Under this bid, the Company may purchase for cancellation up to 46,229,000 of its Common Shares, representing five percent of the approximately 924.6 million Common Shares outstanding as of the filing of the bid on October 22, 2004. On February 4, 2005, the Company received regulatory approval for an amendment to the Normal Course Issuer Bid which increases the number of shares available for purchase from five percent of the issued and outstanding Common Shares to ten percent of the public float of Common Shares (a total of approximately 92.2 million Common Shares). The current Normal Course Issuer Bid expires on October 28, 2005.

Stock Options

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 plans are generally fully exercisable after three years and expire five years after the grant date. Options granted under predecessor and/or related company replacement plans expire up to ten years from the date the options were granted.

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSAR's") attached to them at September 30, 2005. Information related to TSAR's is included in Note 10.

	Stock Options *(millions)*	**Weighted Average Exercise Price *(C$)***
Outstanding, Beginning of Year	**36.2**	**23.15**
Exercised	**(13.9)**	**22.90**
Forfeited	**(0.4)**	**21.22**
Outstanding, End of Period	**21.9**	**23.34**
Exercisable, End of Period	**17.6**	**23.19**

	Outstanding Options			**Exercisable Options**	
Range of Exercise Price	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *(C$)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *(C$)*
10.00 to 22.99	1.9	2.4	15.87	1.7	15.24
23.00 to 23.50	1.5	0.9	23.17	1.4	23.16
23.51 to 23.99	7.1	2.5	23.89	3.7	23.89
24.00 to 24.49	10.8	1.5	24.18	10.6	24.18
24.51 to 25.99	0.6	2.8	25.25	0.2	25.31
	21.9	1.9	23.34	17.6	23.19

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

9. SHARE CAPITAL (continued)

EnCana has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Stock options granted in 2004 and 2005 have an associated Tandem Share Appreciation Right attached. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share for the three months ended September 30, 2005 would be unchanged (three months ended 2004 - $384 million; $0.42 per common share - basic; $0.41 per common share - diluted). Pro forma Net Earnings and Net Earnings per Common Share for the nine months ended September 30, 2005 would be unchanged (2004 - $906 million; $0.98 per common share - basic; $0.97 per common share diluted).

10. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at September 30, 2005. Additional information is contained in Note 16 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2004.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2004	**2005**	2004
Current Service Cost	**$ 1**	$ 1	**$ 5**	$ 4
Interest Cost	**4**	3	**11**	9
Expected Return on Plan Assets	**(3)**	(2)	**(10)**	(8)
Amortization of Net Actuarial Loss	**1**	1	**3**	3
Amortization of Transitional Obligation	**(1)**	-	**(2)**	(1)
Amortization of Past Service Cost	**-**	-	**1**	1
Expense for Defined Contribution Plan	**6**	3	**16**	10
Net Benefit Plan Expense	**$ 8**	$ 6	**$ 24**	$ 18

EnCana previously disclosed in its annual audited Consolidated Financial Statements for the year ended December 31, 2004 that it expected to contribute $6 million to its defined benefit pension plans in 2005. The Company now anticipates that it will contribute $8 million to the defined benefit pension plans in 2005. At September 30, 2005, contributions of $8 million have been made.

B) Share Appreciation Rights ("SAR's")

The following table summarizes the information about SAR's at September 30, 2005:

	Outstanding SAR's	**Weighted Average Exercise Price**
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**930,510**	**18.31**
Exercised	**(662,847)**	**16.35**
Forfeited	**(1,530)**	**23.14**
Outstanding, End of Period	**266,133**	**23.15**
Exercisable, End of Period	**266,133**	**23.15**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**771,860**	**14.40**
Exercised	**(419,589)**	**14.45**
Outstanding, End of Period	**352,271**	**14.34**
Exercisable, End of Period	**352,271**	**14.34**

To September 30, EnCana recorded compensation costs of $19 million related to the outstanding SAR's (2004 - $4 million).

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

10. COMPENSATION PLANS (continued)

C) Tandem Share Appreciation Rights ("TSAR's")

The following table summarizes the information about Tandem SAR's at September 30, 2005:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**1,735,000**	**27.77**
Granted	**7,234,012**	**39.33**
Exercised - SARs	**(136,285)**	**27.24**
Exercised - Options	**(90,275)**	**27.26**
Forfeited	**(379,230)**	**33.95**
Outstanding, End of Period	**8,363,222**	**37.50**
Exercisable, End of Period	**203,830**	**27.40**

To September 30, EnCana recorded compensation costs of $86 million related to the outstanding TSAR's (2004 - $1 million).

D) Deferred Share Units ("DSU's")

The following table summarizes the information about DSU's at September 30, 2005:

	Outstanding DSU's	Weighted Average Exercise Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**750,612**	**24.81**
Granted, Directors	**78,827**	**43.54**
Units, in Lieu of Dividends	**3,806**	**52.26**
Outstanding, End of Period	**833,245**	**26.70**
Exercisable, End of Period	**833,245**	**26.70**

To September 30, EnCana recorded compensation costs of $26 million related to the outstanding DSU's (2004 - $6 million).

E) Performance Share Units ("PSU's")

The following table summarizes the information about PSU's at September 30, 2005:

	Outstanding PSU's	Weighted Average Grant Price
Canadian Dollar Denominated *(C$)*		
Outstanding, Beginning of Year	**3,294,206**	**26.71**
Granted	**1,726,292**	**38.16**
Forfeited	**(270,008)**	**30.63**
Outstanding, End of Period	**4,750,490**	**30.64**
Exercisable, End of Period	**-**	**-**
U.S. Dollar Denominated *(US$)*		
Outstanding, Beginning of Year	**449,230**	**20.56**
Granted	**388,928**	**30.94**
Forfeited	**(56,602)**	**27.82**
Outstanding, End of Period	**781,556**	**25.20**
Exercisable, End of Period	**-**	**-**

To September 30, EnCana recorded compensation costs of $57 million related to the outstanding PSU's (2004 - $17 million).

At September 30, 2005, EnCana has approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU's.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

11. 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)	2005	2005	**2005**	2004	**2005**	2004
Weighted Average Common Shares Outstanding - Basic	891.8	872.0	**855.1**	923.4	**872.9**	922.0
Effect of Dilutive Securities	17.2	19.9	**20.7**	9.0	**21.3**	12.2
Weighted Average Common Shares Outstanding - Diluted	909.0	891.9	**875.8**	932.4	**894.2**	934.2

The amounts above have been restated to reflect the effect of the common share split approved in April 2005.

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, EnCana entered into various financial instrument agreements and physical contracts. The following information presents all positions for financial instruments.

Realized and Unrealized (Loss) Gain on Risk Management Activities

The following tables summarize the gains and losses on risk management activities:

	Realized			
	Q1	Q2	**Q3**	**YTD**
Revenues, Net of Royalites	$ (20)	$ (114)	**$ (201)**	**$ (335)**
Operating Expenses and Other	5	5	**7**	**17**
Total Loss on Risk Management - Continuing Operations	(15)	(109)	**(194)**	**(318)**
Loss on Risk Management - Discontinued Operations	(23)	(32)	**(50)**	**(105)**
	$ (38)	$ (141)	**$ (244)**	**$ (423)**

	Unrealized			
	Q1	Q2	**Q3**	**YTD**
Revenues, Net of Royalites	$ (972)	$ 315	**$ (939)**	**$ (1,596)**
Operating Expenses and Other	3	(1)	**1**	**3**
Total (Loss) Gain on Risk Management - Continuing Operations	(969)	314	**(938)**	**(1,593)**
(Loss) Gain on Risk Management - Discontinued Operations	(20)	31	**39**	**50**
	$ (989)	$ 345	**$ (899)**	**$ (1,543)**

Amounts Recognized on Transition

As discussed in Note 2 to the annual audited Consolidated Financial Statements for the year ended December 31, 2004, on January 1, 2004, the fair value of all outstanding financial instruments that were not considered accounting hedges was recorded in the Consolidated Balance Sheet with an offsetting net deferred loss amount (the "transition amount"). The transition amount is recognized into net earnings over the life of the related contracts. Changes in fair value after that time are recorded in the Consolidated Balance Sheet with an associated unrealized gain or loss recorded in net earnings. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

At September 30, 2005, a net unrealized gain remains to be recognized over the next four years as follows:

	Unrealized Gain
2005	
Three months ended December 31, 2005	$ 10
Total remaining to be recognized in 2005	$ 10
2006	$ 24
2007	15
2008	1
Total to be recognized in 2006 through to 2008	$ 40
Total to be recognized	$ 50
Total to be recognized - Continuing Operations	$ 50
Total to be recognized - Discontinued Operations	-
	$ 50

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2005 to September 30, 2005:

	Transition Amounts	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	$ (72)	$ (189)	
Change in Fair Value of Contracts in Place at Beginning of Year	-	(1,112)	$ (1,112)
Fair Value of Contracts in Place at Transition Realized in 2005	22	(22)	-
Fair Value of Contracts Entered into Since Beginning of Year	-	(431)	(431)
Fair Value of Contracts Outstanding	$ (50)	$ (1,754)	$ (1,543)
Unamortized Premiums Paid on Collars and Options		224	
Fair Value of Contracts Outstanding and Premiums Paid, End of Period		$ (1,530)	
Amounts Allocated to Continuing Operations	$ (50)	$ (1,508)	$ (1,593)
Amounts Allocated to Discontinued Operations	-	(22)	50
	$ (50)	$ (1,530)	$ (1,543)

At September 30, 2005, the net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at September 30, 2005
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	**$ 1**
Investments and other assets	**1**
Accounts payable and accrued liabilities	**29**
Other liabilities	**23**
Net Deferred Gain - Continuing Operations	**50**
Net Deferred Loss - Discontinued Operations	**-**
	$ 50
Risk Management	
Current asset	**$ 432**
Long-term asset	**316**
Current liability	**1,948**
Long-term liability	**308**
Net Risk Management Liability - Continuing Operations	**(1,508)**
Net Risk Management Liability - Discontinued Operations	**(22)**
	$ (1,530)

A summary of all unrealized estimated fair value financial positions is as follows:	**As at September 30, 2005**
Commodity Price Risk	
Natural gas	**$ (1,412)**
Crude oil	**(117)**
Power	**4**
Interest Rate Risk	**17**
Total Fair Value Positions - Continuing Operations	**(1,508)**
Total Fair Value Positions - Discontinued Operations	**(22)**
	$ (1,530)

Information with respect to power and interest rate risk contracts in place at December 31, 2004 is disclosed in Note 17 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at September 30, 2005.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Natural Gas

At September 30, 2005, the Company's gas risk management activities from financial contracts had an unrealized loss of $1,544 million and a fair market value position of $(1,412) million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Average Price		Fair Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	802	2005	6.74	US$/Mcf	$ (533)
Colorado Interstate Gas (CIG)	114	2005	4.87	US$/Mcf	(63)
Other	110	2005	5.21	US$/Mcf	(64)
NYMEX Fixed Price	525	2006	5.65	US$/Mcf	(1,125)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(194)
Houston Ship Channel (HSC)	90	2006	5.08	US$/Mcf	(185)
Rockies	35	2006	4.45	US$/Mcf	(69)
Waha	30	2006	4.79	US$/Mcf	(62)
San Juan	16	2006	4.50	US$/Mcf	(32)
NYMEX Fixed Price	240	2007	7.76	US$/Mcf	(166)
Collars and Other Options					
Purchased NYMEX Put Options	1,062	2005	5.66	US$/Mcf	(24)
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(19)
Purchased NYMEX Put Options	987	2006	6.69	US$/Mcf	(61)
Purchased NYMEX Put Options	240	2007	6.00	US$/Mcf	(4)
Basis Contracts					
Fixed NYMEX to AECO Basis	908	2005	(0.67)	US$/Mcf	182
Fixed NYMEX to Rockies Basis	263	2005	(0.49)	US$/Mcf	62
Fixed NYMEX to CIG Basis	185	2005	(0.81)	US$/Mcf	36
Other	267	2005	(0.35)	US$/Mcf	43
Fixed NYMEX to AECO Basis	759	2006	(0.67)	US$/Mcf	186
Fixed NYMEX to Rockies Basis	324	2006	(0.58)	US$/Mcf	120
Fixed NYMEX to CIG Basis	301	2006	(0.83)	US$/Mcf	99
Other	182	2006	(0.36)	US$/Mcf	37
Fixed Rockies to CIG Basis	12	2007	(0.10)	US$/Mcf	-
Fixed NYMEX to AECO Basis	401	2007-2008	(0.69)	US$/Mcf	88
Fixed NYMEX to Rockies Basis	350	2007-2008	(0.63)	US$/Mcf	188
Fixed NYMEX to CIG Basis	157	2007-2009	(0.75)	US$/Mcf	120
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	27	2005	5.90	US$/Mcf	14
Waha Purchase	23	2006	5.32	US$/Mcf	43
Basis Contracts					
Fixed NYMEX to Ventura	29	2005	(0.99)	US$/Mcf	(5)
					(1,388)
Other Financial Positions *					(156)
Total Unrealized Loss on Financial Contracts					(1,544)
Unamortized Premiums Paid on Options					132
Total Fair Value Positions					$ (1,412)

* Other financial positions are part of the ongoing operations of the Company's proprietary production management and gas storage optimization activities.

Notes to Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Crude Oil

At September 30, 2005, the Company's oil risk management activities from financial contracts had an unrealized loss of $231 million and a fair market value position of $(139) million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Fair Market Value
Fixed WTI NYMEX Price	37,000	2005	28.40	$ (128)
Costless 3-Way Put Spread	9,000	2005	20.00/25.00/28.78	(31)
Unwind WTI NYMEX Fixed Price	(7,200)	2005	42.70	16
Purchased WTI NYMEX Call Options	(38,000)	2005	49.76	55
Purchased WTI NYMEX Put Options	35,000	2005	40.00	(6)
Fixed WTI NYMEX Price	15,000	2006	34.56	(171)
Unwind WTI NYMEX Fixed Price	(1,300)	2006	52.75	6
Purchased WTI NYMEX Call Options	(13,700)	2006	61.24	32
Purchased WTI NYMEX Put Options	57,000	2006	50.00	(3)
Purchased WTI NYMEX Put Options	43,000	2007	44.44	(4)
				(234)
Other Financial Positions *				3
Total Unrealized Loss on Financial Contracts				(231)
Unamortized Premiums Paid on Options				92
Total Fair Value Positions				$ (139)
Total Fair Value Positions - Continuing Operations				$ (117)
Total Fair Value Positions - Discontinued Operations				(22)
				$ (139)

* Other financial positions are part of the ongoing operations of the Company's proprietary production management.

13. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2005.

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2005				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
TOTAL CONSOLIDATED									
Cash Flow	**4,916**	**1,931**	1,572	1,413	4,980	1,491	1,363	1,131	995
Per share - Basic	**5.63**	**2.26**	1.80	1.58	5.41	1.62	1.48	1.23	1.08
- Diluted	**5.50**	**2.20**	1.76	1.55	5.32	1.60	1.46	1.21	1.07
Net Earnings (Loss)	**1,060**	**266**	839	(45)	3,513	2,580	393	250	290
Per share - Basic	**1.21**	**0.31**	0.96	(0.05)	3.82	2.81	0.43	0.27	0.31
- Diluted	**1.19**	**0.30**	0.94	(0.05)	3.75	2.77	0.42	0.27	0.31
Operating Earnings [1]	**1,970**	**704**	655	611	1,976	573	559	379	465
Per share - Diluted	**2.20**	**0.80**	0.73	0.67	2.11	0.62	0.60	0.41	0.50
CONTINUING OPERATIONS									
Cash Flow from Continuing Operations	**4,643**	**1,823**	1,512	1,308	4,605	1,429	1,259	1,021	896
Net Earnings (Loss) from Continuing Operations	**927**	**266**	786	(125)	2,211	1,188	432	265	326
Per share - Basic	**1.06**	**0.31**	0.90	(0.14)	2.40	1.29	0.47	0.29	0.35
- Diluted	**1.04**	**0.30**	0.88	(0.14)	2.36	1.28	0.46	0.28	0.35
Operating Earnings - Continuing Operations [2]	**1,872**	**731**	623	518	1,989	612	553	362	462
Foreign Exchange Rates (US$ per C$1)									
Average	**0.817**	**0.833**	0.804	0.815	0.768	0.820	0.765	0.736	0.759
Period end	**0.861**	**0.861**	0.816	0.827	0.831	0.831	0.791	0.746	0.763

[1] Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

[2] Operating Earnings - Continuing Operations is a non-GAAP measure defined as Net Earnings from Continuing Operations excluding the after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

Common Share Information (restated for the effect of the share split)	2005				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**853.8**	**853.8**	860.2	881.7	900.6	900.6	924.0	922.0	919.6
Average - Basic	**872.9**	**855.1**	872.0	891.8	920.8	917.6	923.4	920.6	921.8
Average - Diluted	**894.2**	**875.8**	891.9	909.0	936.0	929.8	932.4	931.0	934.2
Price Range *($ per share)*									
TSX - C$									
High	**68.70**	**68.70**	51.27	44.28	35.01	35.01	30.30	29.87	29.64
Low	**32.55**	**47.72**	39.05	32.55	25.50	28.95	26.15	26.50	25.50
Close	**67.85**	**67.85**	48.33	42.72	34.20	34.20	29.18	28.81	28.35
NYSE - US$									
High	**58.49**	**58.49**	41.56	36.45	28.72	28.72	23.46	22.37	22.13
Low	**26.45**	**39.26**	31.31	26.45	19.03	23.05	19.98	19.03	19.18
Close	**58.31**	**58.31**	39.59	35.21	28.53	28.53	23.15	21.58	21.56
Share Volume Traded *(millions)*	**1,066.8**	**388.9**	327.3	350.6	1,056.1	326.7	229.5	242.3	257.6
Share Value Traded *(US$ millions weekly average)*	**1,046.2**	**1,400.4**	878.8	852.6	456.9	636.0	364.8	392.9	403.7

Financial Metrics	
Net Debt to Capitalization	**40%**
Net Debt to EBITDA	**1.6x**
Return on Capital Employed	**18%**
Return on Common Equity	**28%**

SUPPLEMENTAL FINANCIAL INFORMATION *(unaudited)*

Financial Statistics ***(continued)***

Net Capital Investment *($ millions)*	**2005**	2004
Upstream		
Canada	**$ 2,780**	$ 2,282
United States	**1,349**	851
Other Countries	**39**	49
	4,168	3,182
Midstream & Market Optimization	**172**	40
Corporate	**49**	28
Core Capital from Continuing Operations	**4,389**	3,250
Upstream		
Acquisitions		
Property		
Canada	**26**	55
United States	**191**	3
Corporate		
Petrovera	**-**	253
Tom Brown, Inc. [1]	**-**	2,335
Dispositions		
Property		
Canada	**(416)**	(797)
United States	**(2,075)**	(274)
Corporate		
Petrovera	**-**	(540)
Midstream & Market Optimization		
Property	**-**	(1)
Other	**21**	-
Corporate	**(2)**	-
Net Acquisition and Disposition activity from Continuing Operations	**(2,255)**	1,034
Discontinued Operations	**133**	584
Net Capital Investment	**$ 2,267**	$ 4,868

[1] Net cash consideration excluding debt acquired of $406 million.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties

Sales Volumes	**2005**				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas *(MMcf/d)*									
Canada									
Production	**2,109**	**2,123**	2,151	2,052	2,105	2,106	2,138	2,177	2,000
Inventory withdrawal / (injection)	**9**	**-**	-	27	(6)	(26)	-	-	-
Canada Sales	**2,118**	**2,123**	2,151	2,079	2,099	2,080	2,138	2,177	2,000
United States	**1,075**	**1,099**	1,061	1,067	869	1,007	958	824	684
Total Produced Gas	**3,193**	**3,222**	3,212	3,146	2,968	3,087	3,096	3,001	2,684
Oil and Natural Gas Liquids *(bbls/d)*									
North America									
Light and Medium Oil	**47,845**	**43,313**	50,020	50,280	56,215	52,725	52,824	64,448	54,940
Heavy Oil	**81,306**	**81,089**	82,274	80,546	84,164	79,336	89,682	79,899	87,729
Natural Gas Liquids [1]									
Canada	**11,779**	**11,924**	11,719	11,692	13,452	13,452	12,804	13,588	13,971
United States	**13,962**	**14,131**	13,095	14,666	12,586	13,957	14,363	12,752	9,237
Total Oil and Natural Gas Liquids	**154,892**	**150,457**	157,108	157,184	166,417	159,470	169,673	170,687	165,877
Total Continuing Operations *(MMcfe/d)*	**4,122**	**4,125**	4,155	4,089	3,966	4,044	4,114	4,025	3,679
DISCONTINUED OPERATIONS									
Ecuador									
Production [2]	**73,737**	**71,896**	73,662	75,695	76,872	76,235	76,567	78,376	76,320
(Under) / over lifting	**(2,294)**	**(3,186)**	(486)	(3,208)	1,121	1,641	(1,721)	(73)	4,662
Ecuador Sales *(bbls/d)*	**71,443**	**68,710**	73,176	72,487	77,993	77,876	74,846	78,303	80,982
United Kingdom *(BOE/d)*	**-**	**-**	-	-	20,973	13,927	20,222	26,728	22,755
Total Discontinued Operations *(MMcfe/d)*	**429**	**412**	439	435	594	551	570	630	623
Total *(MMcfe/d)*	**4,551**	**4,537**	4,594	4,524	4,560	4,595	4,684	4,655	4,302

[1] Natural gas liquids include condensate volumes.

[2] 2005 includes approximately 28,800 bbls/day (2004 full year - 31,000 bbls/day) related to Block 15.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS									
Produced Gas - Canada *($/Mcf)*									
Price	**6.33**	**7.18**	6.08	5.70	5.34	5.86	5.10	5.20	5.21
Production and mineral taxes	**0.10**	**0.10**	0.10	0.09	0.08	0.10	0.09	0.07	0.08
Transportation and selling	**0.37**	**0.36**	0.36	0.37	0.39	0.39	0.37	0.35	0.44
Operating	**0.65**	**0.68**	0.62	0.65	0.52	0.55	0.50	0.49	0.56
Netback	**5.21**	**6.04**	5.00	4.59	4.35	4.82	4.14	4.29	4.13
Produced Gas - United States *($/Mcf)*									
Price	**6.73**	**7.51**	6.60	6.04	5.79	6.53	5.36	5.72	5.39
Production and mineral taxes	**0.68**	**0.75**	0.65	0.62	0.65	0.69	0.57	0.80	0.51
Transportation and selling	**0.46**	**0.49**	0.42	0.46	0.31	0.27	0.26	0.34	0.39
Operating	**0.50**	**0.55**	0.50	0.45	0.37	0.41	0.36	0.37	0.33
Netback	**5.09**	**5.72**	5.03	4.51	4.46	5.16	4.17	4.21	4.16
Produced Gas - Total North America *($/Mcf)*									
Price	**6.46**	**7.29**	6.25	5.81	5.47	6.08	5.18	5.34	5.26
Production and mineral taxes	**0.29**	**0.32**	0.28	0.27	0.25	0.29	0.24	0.27	0.19
Transportation and selling	**0.40**	**0.41**	0.38	0.40	0.36	0.35	0.33	0.35	0.43
Operating	**0.60**	**0.64**	0.58	0.58	0.48	0.50	0.46	0.46	0.50
Netback	**5.17**	**5.92**	5.01	4.56	4.38	4.94	4.15	4.26	4.14
Natural Gas Liquids - Canada *($/bbl)*									
Price	**42.39**	**47.39**	39.55	40.04	31.43	36.73	33.46	28.48	27.27
Production and mineral taxes	**-**	**-**	-	-	-	-	-	-	-
Transportation and selling	**0.41**	**0.48**	0.39	0.35	0.41	0.47	0.45	0.35	0.35
Netback	**41.98**	**46.91**	39.16	39.69	31.02	36.26	33.01	28.13	26.92
Natural Gas Liquids - United States *($/bbl)*									
Price	**46.57**	**53.92**	44.79	40.93	35.43	38.74	36.09	32.93	32.77
Production and mineral taxes	**4.68**	**5.46**	4.37	4.20	3.82	3.94	4.05	3.93	3.09
Transportation and selling	**0.01**	**0.01**	0.01	0.01	-	-	-	-	-
Netback	**41.88**	**48.45**	40.41	36.72	31.61	34.80	32.04	29.00	29.68
Natural Gas Liquids - Total North America *($/bbl)*									
Price	**44.65**	**50.93**	42.32	40.53	33.36	37.75	34.85	30.63	29.46
Production and mineral taxes	**2.54**	**2.96**	2.31	2.34	1.84	2.00	2.14	1.90	1.23
Transportation and selling	**0.19**	**0.23**	0.19	0.16	0.21	0.23	0.21	0.18	0.21
Netback	**41.92**	**47.74**	39.82	38.03	31.31	35.52	32.50	28.55	28.02
Crude Oil - Light and Medium - North America *($/bbl)*									
Price	**44.71**	**55.41**	41.44	38.57	34.67	39.57	37.40	32.43	29.92
Production and mineral taxes	**1.45**	**1.29**	1.71	1.32	0.96	1.38	0.85	0.79	0.86
Transportation and selling	**1.22**	**1.29**	1.20	1.19	1.01	1.04	1.08	0.76	1.19
Operating	**6.32**	**6.24**	6.34	6.38	5.85	6.41	6.49	4.84	5.87
Netback	**35.72**	**46.59**	32.19	29.68	26.85	30.74	28.98	26.04	22.00
Crude Oil - Heavy - North America *($/bbl)*									
Price	**27.80**	**39.69**	22.77	20.76	23.41	21.37	28.01	22.35	21.48
Production and mineral taxes	**0.03**	**0.04**	0.02	0.03	0.04	0.04	0.05	(0.01)	0.06
Transportation and selling	**1.24**	**1.08**	1.13	1.52	1.09	(0.57)	1.63	1.50	1.69
Operating	**6.33**	**6.57**	6.57	5.83	5.32	6.27	4.79	4.82	5.44
Netback	**20.20**	**32.00**	15.05	13.38	16.96	15.63	21.54	16.04	14.29
Crude Oil - Total North America *($/bbl)*									
Price	**34.06**	**45.16**	29.83	27.60	27.92	28.63	31.49	26.85	24.73
Production and mineral taxes	**0.56**	**0.48**	0.66	0.53	0.41	0.57	0.34	0.35	0.37
Transportation and selling	**1.23**	**1.15**	1.15	1.39	1.06	0.07	1.42	1.17	1.50
Operating	**6.32**	**6.45**	6.48	6.04	5.53	6.33	5.42	4.83	5.61
Netback	**25.95**	**37.08**	21.54	19.64	20.92	21.66	24.31	20.50	17.25

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
CONTINUING OPERATIONS (continued)									
Total Liquids - Canada *($/bbl)*									
Price	**34.74**	**45.35**	30.58	28.60	28.21	29.36	31.63	26.99	24.95
Production and mineral taxes	**0.51**	**0.43**	0.61	0.48	0.37	0.52	0.31	0.32	0.34
Transportation and selling	**1.16**	**1.09**	1.09	1.31	1.00	0.11	1.35	1.10	1.40
Operating	**5.78**	**5.83**	5.96	5.55	5.05	5.75	4.98	4.42	5.11
Netback	**27.29**	**38.00**	22.92	21.26	21.79	22.98	24.99	21.15	18.10
Total Liquids - Total North America *($/bbl)*									
Price	**35.82**	**46.16**	31.80	29.77	28.77	30.20	32.03	27.43	25.39
Production and mineral taxes	**0.89**	**0.91**	0.92	0.83	0.63	0.82	0.63	0.59	0.49
Transportation and selling	**1.06**	**0.99**	1.00	1.18	0.93	0.10	1.23	1.02	1.32
Operating	**5.27**	**5.33**	5.46	5.03	4.67	5.24	4.55	4.09	4.82
Netback	**28.60**	**38.93**	24.42	22.73	22.54	24.04	25.62	21.73	18.76
Total North America *($/Mcfe)*									
Price	**6.35**	**7.38**	6.03	5.62	5.30	5.83	5.22	5.15	4.98
Production and mineral taxes	**0.26**	**0.29**	0.25	0.24	0.21	0.25	0.21	0.22	0.16
Transportation and selling	**0.35**	**0.35**	0.33	0.36	0.31	0.27	0.30	0.30	0.37
Operating	**0.66**	**0.69**	0.66	0.64	0.55	0.59	0.53	0.52	0.58
Netback	**5.08**	**6.05**	4.79	4.38	4.23	4.72	4.18	4.11	3.87

Impact of Upstream Realized Financial Hedging

Natural Gas *($/Mcf)*	**(0.12)**	**(0.39)**	(0.14)	0.18	(0.22)	(0.37)	(0.15)	(0.25)	(0.08)
Liquids *($/bbl)*	**(5.25)**	**(5.70)**	(4.88)	(5.18)	(7.08)	(8.24)	(8.75)	(6.53)	(4.79)
Total *($/Mcfe)*	**(0.29)**	**(0.52)**	(0.30)	(0.06)	(0.46)	(0.61)	(0.48)	(0.47)	(0.27)

Average Royalty Rates
(excluding impact of realized financial hedging)

Produced Gas									
Canada	**11.6%**	**11.8%**	11.0%	11.9%	12.5%	12.0%	12.2%	12.7%	13.3%
United States	**18.7%**	**19.9%**	17.9%	18.1%	19.6%	19.8%	18.3%	21.1%	19.3%
Crude Oil									
Canada and United States	**8.9%**	**8.7%**	9.2%	8.7%	9.0%	8.7%	8.8%	11.6%	9.4%
Natural Gas Liquids									
Canada	**15.1%**	**15.8%**	15.6%	13.8%	15.7%	16.5%	18.5%	13.1%	14.8%
United States	**17.9%**	**20.1%**	12.7%	20.0%	18.7%	21.4%	13.6%	20.7%	19.2%
Total North America	**13.3%**	**13.8%**	12.6%	13.3%	13.7%	13.8%	13.2%	14.1%	13.7%

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS *(unaudited)*

Operating Statistics - After Royalties (continued)

Per-unit Results
(excluding impact of realized financial hedging)

	2005				2004				
	Year-to-date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
DISCONTINUED OPERATIONS									
Crude Oil - Ecuador *($/bbl)*									
Price	**39.87**	**47.76**	36.37	35.80	28.68	29.97	33.47	27.78	23.82
Production and mineral taxes	**5.18**	**7.66**	4.53	3.42	2.13	2.73	2.62	1.84	1.37
Transportation and selling	**2.38**	**2.45**	2.48	2.21	2.12	1.57	2.36	1.92	2.63
Operating	**5.16**	**6.05**	5.18	4.26	4.39	5.02	4.35	4.14	4.04
Netback	**27.15**	**31.60**	24.18	25.91	20.04	20.65	24.14	19.88	15.78
Crude Oil - United Kingdom *($/bbl)*									
Price	**-**	**-**	-	-	36.92	46.19	40.88	34.68	31.11
Transportation and selling	**-**	**-**	-	-	2.06	2.17	2.44	1.85	1.94
Operating	**-**	**-**	-	-	6.75	5.00	9.98	7.84	3.86
Netback	**-**	**-**	-	-	28.11	39.02	28.46	24.99	25.31

Impact of Upstream Realized Financial Hedging - Crude Oil

Ecuador *($/bbl)*	**(5.36)**	**(7.81)**	(4.90)	(3.48)	(9.66)	(14.60)	(10.31)	(7.13)	(6.69)
United Kingdom *($/bbl)* [(1)]	**-**	**-**	-	-	(7.62)	(6.34)	(11.75)	(7.01)	(5.72)

Average Royalty Rates
(excluding impact of realized financial hedging)

Crude Oil									
Ecuador	**26.5%**	**26.3%**	26.3%	26.9%	27.1%	27.8%	26.5%	26.5%	27.4%

[(1)] Excludes hedges unwound as a result of the United Kingdom disposition.

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