February 15, 2007

EnCana generates 2006 cash flow of US$7.2 billion, or $8.56 per share

Proved reserves additions replace close to 200% of North American production Quarterly dividend doubled to 20 cents per share

CALGARY, February 15, 2007 - EnCana Corporation (TSX & NYSE: ECA) today reports a 3 percent increase in 2006 cash flow per share diluted to US$8.56, or $7.2 billion. Total operating earnings per share diluted in 2006 increased 7 percent to $3.91, or $3.27 billion. Net earnings per share diluted were $6.76, or $5.65 billion, which includes after-tax gains of $2.38 billion due to unrealized mark-to-market accounting for commodity price hedges, gains on sales of discontinued operations and tax rate changes.

Natural gas and oil reserves added through drilling replaced 197 percent of EnCana's 2006 production in continuing operations and increased North American proved reserves by 9 percent to 19.2 trillion cubic feet of gas equivalent (Tcfe). Finding and development costs in total operations were $1.99 per thousand cubic feet equivalent (Mcfe).

Strong financials, resource play production grows 12 percent

"EnCana achieved strong financial results and solid operating performance in 2006. We continued to fortify our future by adding close to double the proved reserves that we produced in 2006, at a competitive cost of about $2 per thousand cubic feet equivalent. Our natural gas production was up 4 percent, while our key resource play production grew 12 percent year- over-year. We achieved all this in a tough operating environment for the industry marked by record breaking activity levels," said Randy Eresman, EnCana's President & Chief Executive Officer.

Transformation to unconventional gas and oil complete

"The year also marked the completion of EnCana's transformation into essentially a pure North American producer focused on unconventional natural gas and integrated oilsands - a strategic position that we believe will create sustainable profitable growth for our company. All of EnCana's production and reserves are now onshore North America," Eresman said.

Dividend doubled

"As a reflection of our increased confidence in the sustainable nature of our North American unconventional business model, the board of directors has doubled our quarterly dividend to 20 cents per share," Eresman said.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report production, sales and reserves on an after-royalties basis. The company is reporting its Ecuador operations and its natural gas storage business as discontinued because EnCana sold them. Total results, which include results from Ecuador and natural gas storage, are reported in the company's financial statements included in this news release and in supplementary documents posted on its website - http://www.encana.com. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

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2006 Highlights

Financial

- Cash flow per share diluted increased 3 percent to $8.56
- Operating earnings per share diluted up 7 percent to $3.91
- Net earnings per share diluted up 76 percent to $6.76

- Generated $892 million in free cash flow (as defined in Note 1 on page 8)
- Net divestitures of $3.0 billion, resulting in net capital investment of $3.3 billion
- Purchased 85.6 million EnCana shares at an average share price of $49.26 under the Normal Course Issuer Bid for a total cost of $4.2 billion
- Reduced shares outstanding at year end by 9 percent, net of share option exercises
- At year end, net debt-to-adjusted-EBITDA was 0.6 times and net debt-to-capitalization was 27 percent

Operating

- Key resource play production up 12 percent
- Natural gas production of 3.37 billion cubic feet per day (Bcf/d), up 4 percent
- Oil and natural gas liquids (NGLs) production of about 167,100 barrels per day (bbls/d), down 26 percent, primarily due to the sale of Ecuador oil assets, which produced an average of 12,366 bbls/d in 2006
- Operating costs of 86 cents per thousand cubic feet equivalent (Mcfe) for continuing operations, up 21 percent due to inflation, a stronger Canadian dollar and higher electricity costs
- Upstream capital investment in continuing operations of $6.2 billion

Reserves

- Added 3.1 Tcfe of proved reserves with drill bit additions and revisions in continuing operations
- Added 2.3 Tcfe of proved reserves in total operations, taking into account the sale of about 822 billion cubic feet equivalent (Bcfe) of proved reserves largely as a result of the Ecuador divestiture
- Proved reserves additions included 160 million bbls (960 Bcfe) at the Foster Creek and Christina Lake oilsands key resource plays
- Proved reserves increased 9 percent in continuing operations and 4 percent in total operations to 19.2 Tcfe
- Finding and development (F&D) costs averaged $1.99 per Mcfe for total operations
- Production replacement of 197 percent for continuing operations; 144 percent for total operations, which includes the sale of Ecuador reserves
- Average three-year reserve replacement cost of $1.56 per Mcfe for continuing operations; $1.34 per Mcfe for total operations

2006 strategic results

- Created an integrated heavy oil business with ConocoPhillips composed of two 50/50 entities - one upstream and one downstream - which became effective January 2, 2007. The integrated business intends to produce 400,000 barrels of Canadian bitumen and refine 275,000 barrels of bitumen at two U.S. refineries by 2015.
- Completed sale of Ecuador assets for $1.1 billion and sale of interest in Brazil oil discovery for proceeds of $367 million
- Sold natural gas storage business for $1.5 billion
- Received environmental impact statement approval for Jonah gas field, which enables advancing toward full development of this key resource play

Financial Summary - Total Consolidated

(for the period ended December 31) ($ millions, except per share amounts)	Q4 2006	Q4 2005	% change	2006	2005	% change

Cash flow	1,761	2,510	- 30	7,161	7,426	- 4
Per share diluted	2.18	2.88	- 24	8.56	8.35	+ 3
Net earnings	663	2,366	- 72	5,652	3,426	+ 65
Per share diluted	0.82	2.71	- 70	6.76	3.85	+ 76
Operating earnings(1)	675	1,271	- 47	3,271	3,241	+ 1
Per share diluted	0.84	1.46	- 42	3.91	3.64	+ 7

Earnings Reconciliation Summary - Total Consolidated

Net earnings from continuing operations	643	1,869	- 66	5,051	2,829	+ 79
Net earnings from discontinued operations	20	497	- 96	601	597	+ 1
Net Earnings	663	2,366	- 72	5,652	3,426	+ 65
(Add back losses & deduct gains)						
Unrealized mark-to-market hedging gain (loss), after-tax	95	746		1,370	(277)	
Unrealized foreign exchange gain (loss) on translation of U.S. dollar debt issued in Canada, after-tax	(128)	(21)		-	92	
Future tax recovery due to Canada and Alberta tax rate reductions	-	-		457	-	
Gain on sale of discontinued operations, after-tax(2)	21	370		554	370	
Operating earnings	675	1,271	- 47	3,271	3,241	+ 1
Per share diluted	0.84	1.46	- 42	3.91	3.64	+ 7

(1) Operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of the gain on the sale of discontinued operations, the after-tax gain/loss on 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.

(2) In 2006, gain on sale of natural gas storage business and loss on sale of Ecuador assets

Cash flow information 2006 (for the period ended December 31, $ millions)	Q4	2006
Cash from Operating Activities	1,697	7,973
Deduct (Add back):		

Net change in other assets and liabilities	90	138
Net change in non-cash working capital from continuing operations	39	3,343
Net change in non-cash working capital from discontinued operations	(193)	(2,669)
Cash Flow(3)	1,761	7,161
Cash flow from Discontinued Operations	19	118
Cash flow from Continuing Operations	1,742	7,043

(3) Cash flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined in the Consolidated Statement of Cash Flows.

Sales & Drilling Summary

	Total Consolidated					
(for the period ended December 31) (After royalties)	Q4 2006	Q4 2005	% change	2006	2005	% change
Natural Gas sales (MMcf/d)	3,406	3,326	+ 2	3,367	3,227	+ 4
Natural gas sales per 1,000 shares (Mcf)	395	358	+ 10	1,499	1,357	+ 10
Oil and NGLs sales (bbls/d)	152,154	229,232	- 34	167,070	227,065	- 26
Oil and NGLs sales per 1,000 shares (Mcfe)	106	148	- 28	446	573	- 22
Total sales (MMcfe/d)	4,319	4,701	- 8	4,369	4,589	- 5
Total sales per 1,000 shares (Mcfe)	501	506	- 1	1,945	1,929	+ 1
Net wells drilled	809	1,146	- 29	3,657	4,676	- 22
	Continuing Operations					
North America Natural Gas sales (MMcf/d)	3,406	3,326	+ 2	3,367	3,227	+ 4
North America Oil and NGLs (bbls/d)	152,154	159,289	- 4	154,704	156,000	- 1
Total sales						

(MMcfe/d)	4,319	4,282	+ 1	4,295	4,163	+ 3
Net wells drilled	809	1,138	- 29	3,650	4,658	- 22

Resource play growth

Key resource play production grows 12 percent in 2006

EnCana's production growth continues to be led by its 12 key resource plays, which grew by about 12 percent in 2006 and comprise about 62 percent of total production. The strongest growth came from the company's coalbed methane (CBM) production in central and southern Alberta, Bighorn in west central Alberta, Cutbank Ridge in northeast British Columbia and Fort Worth in Texas. In-situ oilsands production from EnCana's Foster Creek steam- assisted gravity drainage project grew about 27 percent in 2006.

Growth from key North American resource plays

Resource Play		Daily Production 2006				
		Full Year	Q4	Q3	Q2	Q1
Natural Gas	(MMcf/d)					
Jonah		464	487	455	450	461
Piceance		326	335	331	324	316
East Texas		99	95	106	93	99
Fort Worth		101	99	104	108	93
Greater Sierra		213	212	209	224	208
Cutbank Ridge		170	199	167	173	140
Bighorn		91	99	97	95	72
CBM(1)		194	211	209	179	177
Shallow Gas		600	601	593	590	615
Oil	(Mbbls/d)					
Foster Creek		37	41	37	33	36
Christina Lake		6	6	6	6	6
Pelican Lake		24	20	23	22	29
Total	(MMcfe/d)	2,656	2,740	2,668	2,601	2,609
% change from prior year's period		12.3	6.7	12.1	12.5	18.8

Resource Play		Daily Production 2005				
		Full Year	Q4	Q3	Q2	Q1
Natural Gas	(MMcf/d)					
Jonah		435	454	440	416	431

Piceance	307	326	302	302	300
East Texas	90	98	94	85	82
Fort Worth	70	88	66	63	61
Greater Sierra	219	226	225	228	195
Cutbank Ridge	92	125	105	80	56
Bighorn	55	56	57	53	56
CBM(1)	112	165	117	104	59
Shallow Gas	625	625	616	633	625
Oil (Mbbls/d)					
Foster Creek	29	35	27	24	30
Christina Lake	5	5	6	7	4
Pelican Lake	26	28	27	27	21
Total (MMcfe/d)	2,366	2,567	2,381	2,312	2,197
% change from prior year's period	20.0				

(1) CBM 2005 volumes restated to report commingled gas volumes from the coal and sand intervals based on regulatory approval.

Drilling activity in key North American resource plays

Resource Play	Net Wells Drilled 2006 Full Year	Q4	Q3	Q2	Q1
Natural Gas					
Jonah	163	41	48	48	26
Piceance	220	50	48	59	63
East Texas	59	11	12	17	19
Fort Worth	97	19	22	27	29
Greater Sierra	115	5	16	34	60
Cutbank Ridge	116	19	35	36	26
Bighorn	52	7	7	18	20
CBM(1)	729	157	156	35	381
Shallow Gas	1,164	326	442	199	197
Oil					
Foster Creek	6	-	-	-	6
Christina Lake	2	-	-	-	2
Pelican Lake	-	-	-	-	-
Total net wells	2,723	635	786	473	829

Resource Play	Net Wells Drilled 2005 Full

	Year	Q4	Q3	Q2	Q1
Natural Gas					
Jonah	104	21	25	30	28
Piceance	266	55	69	65	77
East Texas	84	20	21	22	21
Fort Worth	59	20	18	12	9
Greater Sierra	164	25	33	47	59
Cutbank Ridge	135	34	40	38	23
Bighorn	51	20	10	10	11
CBM(1)	1,245	344	314	242	345
Shallow Gas	1,267	288	341	365	273
Oil					
Foster Creek	39	13	14	2	10
Christina Lake	-	-	-	-	-
Pelican Lake	52	-	3	33	16
Total net wells	3,466	840	888	866	872

(1) CBM 2005 wells restated to report commingled gas drilling from the coal and sand intervals based on regulatory approval.

Year-end 2006 proved reserves

EnCana achieved 9 percent growth in proved reserves from continuing operations at a competitive finding and development cost of less than $2.00 per Mcfe

Total natural gas and liquids proved reserves

- Proved reserves increased 4 percent to 19.2 Tcfe
- Proved reserves in North America (continuing operations) increased 9 percent
- Proved reserves additions were 3.1 Tcfe in continuing operations, compared to production of 1.6 Tcfe

Natural gas reserves

- Proved gas reserves increased 5 percent to 12.4 Tcf
- Proved gas additions were 1.9 Tcf, compared to production of 1.2 Tcf
- Gas production replacement of 152 percent

Oil and NGLs reserves

- Proved oil and NGLs reserves in continuing operations increased 15 percent to 1.1 billion bbls
- Proved oil and NGLs additions in continuing operations were 205 million bbls, compared to production of 57 million bbls
- Oil and NGLs production replacement of 357 percent in continuing operations

Bitumen reserves (included in oil and NGLs)

- Bitumen reserves up 22 percent to 800 million bbls
- Proved bitumen additions were 160 million bbls compared to production of 17 million bbls

Reserves additions costs

- Total three-year reserves replacement cost averaged $1.34 per Mcfe
- Total 2006 finding and development cost of $1.99 per Mcfe

All of EnCana's proved reserves are evaluated by independent qualified reserves evaluators.

2006 Proved Reserves Reconciliation

Crude oil and

	Natural gas (Bcf)			Natural Gas Liquids (MMbbls)		
	Canada	USA	Total	Canada Conv.	Canada Bitumen	Canada Total
Start of 2006	6,517	5,267	11,784	275.1	657.4	932.5
Revisions & improved recovery	301	(88)	213	27.5	(66.5)	(39.0)
Extensions & discoveries	1,014	606	1,620	12.6	226.1	238.7
Acquisitions	-	68	68	-	-	-
Divestitures	(6)	(32)	(38)	(0.1)	-	(0.1)
Production	(798)	(431)	(1,229)	(35.3)	(17.4)	(52.7)
End of 2006	7,028	5,390	12,418	279.8	799.6	1,079.4
Developed	4,718	2,964	7,682	215.3	101.6	316.9
Undeveloped	2,310	2,426	4,736	64.5	698.0	762.5
Total						
% Change(2)	+ 8	+ 2	+ 5	+ 2	+ 22	+ 16
Partnership contribution(3)	-	-	-	-	(398.0)	(398.0)
Effective Jan. 2, 2007	7,028	5,390	12,418	279.8	401.6	681.4

2006 Proved Reserves Reconciliation

	Crude oil and Natural Gas Liquids (MMbbls)			Gas Equivalent(1) (Bcfe)	
	USA	Ecuador	Total	Total	Continuing Ops.(4)
Start of 2006	53.1	135.0	1,120.6	18,507	17,697
Revisions & improved recovery	(1.1)	-	(40.1)	(27)	(27)
Extensions & discoveries	6.4	-	245.1	3,091	3,091
Acquisitions	0.3	-	0.3	69	69
Divestitures	-	(130.6)	(130.7)	(822)	(38)
Production	(4.7)	(4.4)	(61.8)	(1,600)	(1,574)
End of 2006	54.0	-	1,133.4	19,218	19,218

Developed	33.5	-	350.4	9,784	9,784
Undeveloped	20.5	-	783.0	9,434	9,434
Total				19,218	19,218
% Change(2)	+ 2		+ 1	+ 4	+ 9
Partnership contribution(3)	-	-	(398.0)	(2,388)	(2,388)
Effective Jan. 2, 2007	54.0	-	735.4	16,830	16,830

(1) Gas equivalency has been calculated by EnCana. See the Advisory Regarding Reserves Data and Other Oil and Gas Information accompanying this release.
(2) EnCana's growth in proved reserves in 2006 is expressed as the percentage change from the start to the end of the year.
(3) Effective January 2, 2007, EnCana established a heavy oil integration arrangement with ConocoPhillips, resulting in ConocoPhillips acquiring a 50 percent interest in EnCana's Foster Creek and Christina Lake oilsands projects and EnCana acquiring a 50 percent interest in ConocoPhillips' Wood River and Borger refineries.
(4) Continuing operations are composed of North American operations, and exclude the Ecuador assets, which were sold in 2006.

Proved Reserves Costs

Capital investment ($ millions)	2006	2005	2004	Cumulative 2004-06
Finding and development	6,107	6,231	4,792	17,130
Acquisitions	368	472	3,469	4,309
Divestitures	(1,639)	(2,552)	(3,827)	(8,018)
Net capital investment	4,836	4,151	4,434	13,421
Total reserve additions (Bcfe)	2,311	4,542	3,163	10,016
($/Mcfe)				3-year average
Reserve replacement cost	2.09	0.91	1.40	1.34
Finding, development and acquisition cost	2.07	1.36	1.70	1.66
Finding and development cost	1.99	1.29	1.44	1.52

NOTE: This table excludes the impact of the bitumen reserves revisions of

2004 and bitumen reserves reinstatement in 2005.

2006 natural gas and oil prices

2006 Natural Gas and Oil Prices
(excludes financial hedging)

Natural gas ($/Mcf)	Q4 2006	Q4 2005	% change	2006	2005	% change
NYMEX Price	6.55	12.96	- 49	7.22	8.62	- 16
EnCana Realized Gas Price	5.79	10.29	- 44	6.25	7.46	- 16
Oil and NGLs ($/bbl)						
WTI Price	60.17	60.05	+ 1	66.25	56.70	+ 17
Western Canada Select (WCS)	39.08	36.40	+ 7	44.69	36.39	+ 23
Differential WTI/WCS	21.09	23.65	- 11	21.56	20.31	+ 6
EnCana Realized Liquids Price	38.69	37.16	+ 4	43.71	36.17	+ 21

Price risk management

Detailed risk management positions at December 31, 2006 are presented in Note 14 to the 2006 unaudited interim consolidated financial statements. In 2006, EnCana's financial price risk management measures resulted in realized gains of approximately $270 million after-tax, composed of a $386 million gain on gas hedges, a $126 million loss on oil hedges and a $10 million gain on other hedges.

More than 50 percent of expected 2007 natural gas and liquids production has downside price protection

In 2007 EnCana has about 1.76 Bcf/d of expected gas production with downside price protection, composed of 1.52 Bcf/d under fixed price contracts at an average NYMEX equivalent price of $8.49 per Mcf and 240 million cubic feet per day with put options at a NYMEX equivalent strike price of $6.00 per Mcf. In oil, EnCana has about 126,000 bbls/d of expected 2007 oil production with downside price protection, composed of 34,500 bbls/d under fixed price contracts at an average West Texas Intermediate (WTI) price of $64.40 per bbl, plus put options on 91,500 bbls/d at an average strike price of WTI $55.34 per bbl. This price hedging strategy helps reduce uncertainty in cash flow during periods of commodity price volatility.

2007 gas production forecast to increase 9 percent per share

In 2007, natural gas production, which represents more than 80 percent of EnCana's production, is expected to increase about 3 percent, or 9 percent per share based on expected share purchases, to about 3.46 Bcf/d. Oil production is expected to average about 138,000 bbls/d. Total production in 2007, prior to the allocation of oilsands volumes to ConocoPhillips as part of the heavy oil integration, was expected to be up 4 percent. With the creation of the integrated oilsands business, EnCana expects 2007 total production to be about 4.28 Bcfe/d, about the same as in 2006, or an increase of about 4 percent per share.

Corporate developments

Quarterly dividend increased 100 percent to 20 cents per share

EnCana's board of directors declared a quarterly dividend of 20 cents per share, which is payable on March 30, 2007 to common shareholders of record as of March 15, 2007. This is double the amount of the previous quarterly

dividend.

EnCana Normal Course Issuer Bid purchases

In 2006, EnCana purchased about 85.6 million common shares, representing approximately 10 percent of the company's outstanding shares on December 31, 2005, at an average price of approximately $49.26 per common share. As at December 31, 2006 there were approximately 778 million common shares issued and outstanding in total. EnCana plans to fund its continuing Normal Course Issuer Bid purchases with cash flow and proceeds from potential divestitures. To date in 2007, EnCana has purchased about 10.8 million shares at an average cost of $45.64 per share.

Financial strength

EnCana targets a net debt-to-capitalization ratio between 30 and 40 percent. EnCana's balance sheet strengthened during 2006. At December 31, 2006, the company's net debt-to-capitalization ratio was 27:73, down from 33:67 at the end of 2005. EnCana's net debt-to-adjusted-EBITDA multiple, on a trailing 12-month basis, was 0.6 times at the end of 2006, down from 1.1 times at the end of 2005.

CONFERENCE CALL TODAY

EnCana Corporation will host a conference call and webcast today to discuss fourth quarter and year-end 2006 financial and operating results at 11:00 a.m. MT (1:00 p.m. ET). To participate, please dial (877) 704-5384 (toll-free in North America) or (913) 312-1297 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 3:00 p.m. MT on February 15 until midnight February 19, 2007 by dialling (888) 203-1112 or (719) 457-0820 and entering access code 4419778. A live audio webcast of the conference call will also be available via EnCana's website, www.encana.com, under Investor Relations. The webcast will be archived for approximately 90 days.

NOTE 1: Non-GAAP measures

This news release contains references to cash flow, total operating earnings and free cash flow.

- Cash flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital from continuing operations and net change in non-cash working capital from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.
- 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 that these excluded 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.
- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of core capital investment.

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.

EnCana Corporation

With an enterprise value of approximately US$45 billion, EnCana is a leading North American unconventional natural gas and integrated oilsands

company. By partnering with employees, community organizations and other businesses, EnCana contributes to the strength and sustainability of the communities where it operates. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

RESERVES COST DEFINITIONS - Production replacement is calculated by dividing reserves additions by production in the same period. Reserves additions over a given period, in this case 2006, are calculated by summing one or more of revisions and improved recovery, extensions and discoveries, acquisitions and divestitures. Reserve replacement cost is calculated by dividing total capital invested in finding, development and acquisitions net of divestitures by reserve additions in the same period. Finding and development cost is calculated by dividing total capital invested in finding and development activities by additions to proved reserves, before acquisitions and divestitures, which is the sum of revisions, extensions and discoveries. Finding, development and acquisition cost is calculated by dividing total capital invested in finding, development and acquisition activities by additions to proved reserves, before divestitures, which is the sum of revisions, extensions, discoveries and acquisitions. Proved reserves added in 2006 included both developed and undeveloped quantities. Additions to EnCana's proved undeveloped reserves were consistent with EnCana's resource play focus. The company estimates that approximately two-thirds of its proved undeveloped reserves will be developed within the next three to four years. 2006 finding, development and acquisition capital includes investment in long lead time projects. EnCana uses the aforementioned metrics as indicators of relative performance, along with a number of other measures. Many performance measures exist, all measures have limitations and historical measures are not necessarily indicative of future performance.

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 represent value equivalency at the well head.

Unbooked resource potential

EnCana defines unbooked resource potential as quantities of oil and natural gas on existing landholdings 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. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

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 or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this news release include, but are not limited to: future economic and operating performance (including per share growth, cash flow and increase in net asset value); anticipated life of proved reserves; anticipated unbooked resource potential; anticipated conversion of unbooked resource potential to proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; the expected proceeds from planned divestitures; planned expansion of in-situ oilsands production; anticipated crude oil and natural gas prices; anticipated expansion and production at Foster Creek and Christina Lake; anticipated increased capacity for the two U.S. refineries (including by 2015); anticipated drilling inventory; expected proportion of total production and cash flows contributed by natural gas; anticipated success of EnCana's market risk mitigation strategy and EnCana's ability to participate in commodity price upside and to provide downside price protection; anticipated purchases pursuant to the Normal Course Issuer Bid; estimated recycle ratios; potential demand for natural gas; anticipated production in 2007 and beyond; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs sales in 2007 and beyond; anticipated costs and inflationary pressures; 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 and assumptions regarding oil and gas prices; assumptions based upon the company's current guidance; 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 ability of the company and ConocoPhillips to successfully manage and operate the integrated North American heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology; 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; 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, except as required by law, 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.

Interim Consolidated Financial Statements
(unaudited)
For the period ended December 31, 2006

EnCana Corporation

U.S. DOLLARS

CONSOLIDATED STATEMENT OF EARNINGS (unaudited)

($ millions, except per share amounts)		Three Months Ended December 31, 2006	Three Months Ended December 31, 2005	Twelve Months Ended December 31, 2006	Twelve Months Ended December 31, 2005
REVENUES, NET OF ROYALTIES	(Note 3)				
Upstream		$ 2,812	$ 3,525	$ 11,342	$ 10,772
Market Optimization		735	1,417	3,007	4,267
Corporate - Unrealized gain (loss) on risk management		129	991	2,050	(466)
		3,676	5,933	16,399	14,573
EXPENSES	(Note 3)				
Production and mineral taxes		80	162	349	453
Transportation and selling		275	211	1,070	845
Operating		428	452	1,655	1,438
Purchased product		702	1,376	2,862	4,159
Depreciation, depletion and amortization		766	751	3,112	2,769
Administrative		84	63	271	268
Interest, net	(Note 6)	142	104	396	524
Accretion of asset retirement obligation	(Note 10)	13	10	50	37
Foreign exchange (gain) loss, net	(Note 7)	172	37	14	(24)
Stock-based compensation - options		-	3	-	15
(Gain) on divestitures	(Note 5)	(2)	-	(323)	-
		2,660	3,169	9,456	10,484
NET EARNINGS BEFORE INCOME TAX		1,016	2,764	6,943	4,089
Income tax expense	(Note 8)	373	895	1,892	1,260

NET EARNINGS FROM CONTINUING OPERATIONS		643	1,869	5,051	2,829
NET EARNINGS FROM DISCONTINUED OPERATIONS	(Note 4)	20	497	601	597
NET EARNINGS		$ 663	$ 2,366	$ 5,652	$ 3,426

NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	(Note 13)				
Basic		$ 0.81	$ 2.19	$ 6.16	$ 3.26
Diluted		$ 0.80	$ 2.14	$ 6.04	$ 3.18
NET EARNINGS PER COMMON SHARE	(Note 13)				
Basic		$ 0.84	$ 2.77	$ 6.89	$ 3.95
Diluted		$ 0.82	$ 2.71	$ 6.76	$ 3.85

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (unaudited)

		Twelve Months Ended December 31,	
($ millions)		2006	2005
RETAINED EARNINGS, BEGINNING OF YEAR		$ 9,481	$ 7,935
Net Earnings		5,652	3,426
Dividends on Common Shares		(304)	(238)
Charges for Normal Course Issuer Bid	(Note 11)	(3,485)	(1,642)
RETAINED EARNINGS, END OF YEAR		$ 11,344	$ 9,481

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET (unaudited)

		As at December 31, 2006	As at December 31, 2005
($ millions)			
ASSETS			
Current Assets			
Cash and cash equivalents		$ 402	$ 105
Accounts receivable and accrued revenues		1,721	1,851
Risk management	(Note 14)	1,403	495
Inventories		176	103
Assets of discontinued operations	(Note 4)	-	1,050
		3,702	3,604
Property, Plant and Equipment, net	(Note 3)	28,213	24,881
Investments and Other Assets		533	496
Risk Management	(Note 14)	133	530
Assets of Discontinued Operations	(Note 4)	-	2,113

Goodwill		2,525	2,524
	(Note 3)	$ 35,106	$ 34,148

LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,494	$ 2,741
Income tax payable		926	392
Risk management	(Note 14)	14	1,227
Liabilities of discontinued operations	(Note 4)	-	438
Current portion of long-term debt	(Note 9)	257	73
		3,691	4,871
Long-Term Debt	(Note 9)	6,577	6,703
Other Liabilities		79	93
Risk Management	(Note 14)	2	102
Asset Retirement Obligation	(Note 10)	1,051	816
Liabilities of Discontinued Operations	(Note 4)	-	267
Future Income Taxes		6,240	5,289
		17,640	18,141
Shareholders' Equity			
Share capital	(Note 11)	4,587	5,131
Paid in surplus		160	133
Retained earnings		11,344	9,481
Foreign currency translation adjustment		1,375	1,262
		17,466	16,007
		$ 35,106	$ 34,148

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS (unaudited)

		Three Months Ended December 31,		Twelve Months Ended December 31,	
($ millions)		2006	2005	2006	2005
OPERATING ACTIVITIES					
Net earnings from continuing operations		$ 643	$ 1,869	$ 5,051	$ 2,829
Depreciation, depletion and amortization		766	751	3,112	2,769
Future income taxes	(Note 8)	260	717	950	56
Cash tax on sale of assets	(Note 5)	-	(13)	49	578
Unrealized (gain) loss on risk management	(Note 14)	(141)	(985)	(2,060)	469
Unrealized					

foreign exchange (gain) loss		155	28	76	(50)
Accretion of asset retirement obligation	(Note 10)	13	10	50	37
(Gain) on divestitures	(Note 5)	(2)	-	(323)	-
Other		48	13	138	274
Cash flow from discontinued operations		19	120	118	464
Net change in other assets and liabilities		90	(108)	138	(281)
Net change in non-cash working capital from continuing operations		39	1,165	3,343	497
Net change in non-cash working capital from discontinued operations		(193)	(140)	(2,669)	(212)
Cash From Operating Activities		1,697	3,427	7,973	7,430
INVESTING ACTIVITIES					
Capital expenditures	(Note 3)	(1,250)	(2,362)	(6,600)	(6,925)
Proceeds on disposal of assets	(Note 5)	55	30	689	2,523
Cash tax on sale of assets	(Note 5)	-	13	(49)	(578)
Net change in investments and other		40	(161)	2	(109)
Net change in non-cash working capital from continuing operations		188	165	19	330
Discontinued operations		180	572	2,557	239
Cash (Used in) Investing Activities		(787)	(1,743)	(3,382)	(4,520)
FINANCING ACTIVITIES					
Net issuance (repayment) of revolving long-term debt		646	(1,513)	134	(538)
Repayment of long-term debt		-	(145)	(73)	(1,104)
Issuance of long-term debt		-	-	-	429
Issuance of					

common shares (Note 11)	39	24	179	294
Purchase of common shares (Note 11)	(1,246)	-	(4,219)	(2,114)
Dividends on common shares	(78)	(64)	(304)	(238)
Other	(3)	(17)	(11)	(125)
Cash (Used in) Financing Activities	(642)	(1,715)	(4,294)	(3,396)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY	-	1	-	2
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	268	(32)	297	(488)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	134	137	105	593
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 402	$ 105	$ 402	$ 105

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. EnCana's continuing operations are in the business of exploration for, and production and marketing of, natural gas, crude oil and natural gas liquids 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, 2005, except as noted below. 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, 2005.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2006, the Company adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 - Accounting for Purchases and Sales of Inventory with the Same Counterparty. In 2006, purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis in the Consolidated Statement of Earnings. This change has been adopted prospectively and has no effect on the net earnings of the reported periods. As a result of the adoption of this policy, reported Market Optimization revenues and purchased product costs for the three months and twelve months ended December 31, 2006 included offsets of $899 million and $3,238 million, respectively.

3. 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 ventures exploration is mainly focused on opportunities in Brazil, the Middle East, Greenland and France.
- Market Optimization is conducted by the Midstream & Marketing division. 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 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.

Market Optimization purchases substantially all of the Company's North American Upstream production for sale to third party customers.

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 4.

Results of Continuing Operations (For the three months ended December 31)

	Upstream		Market Optimization	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 2,812	$ 3,525	$ 735	$ 1,417
Expenses				
Production and mineral taxes	80	162	-	-
Transportation and selling	276	208	(1)	3
Operating	428	415	13	32
Purchased product	-	-	702	1,376
Depreciation, depletion and amortization	743	731	4	1
Segment Income	$ 1,285	$ 2,009	$ 17	$ 5

	Corporate(*)		Consolidated	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 129	$ 991	$ 3,676	$ 5,933
Expenses				
Production and mineral taxes	-	-	80	162
Transportation and selling	-	-	275	211
Operating	(13)	5	428	452
Purchased product	-	-	702	1,376
Depreciation, depletion and amortization	19	19	766	751
Segment Income	$ 123	$ 967	$ 1,425	$ 2,981

Administrative	84	63
Interest, net	142	104
Accretion of asset retirement obligation	13	10
Foreign exchange (gain) loss, net	172	37
Stock-based compensation - options	-	3
(Gain) on divestitures (Note 5)	(2)	-
	409	217
Net Earnings Before Income Tax	1,016	2,764
Income tax expense	373	895
Net Earnings From Continuing Operations	$ 643	$ 1,869

(*) For the three months ended December 31, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	$ 129	$ 991
Operating Expenses and Other - Corporate	12	(6)
Total Unrealized Gain on Risk Management before-tax - Continuing Operations	$ 141	$ 985

Results of Continuing Operations (For the three months ended December 31)

Upstream	Canada		United States	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 1,966	$ 2,331	$ 765	$ 1,106
Expenses				
Production and mineral taxes	20	29	60	133
Transportation and selling	210	160	66	48
Operating	276	227	76	64
Depreciation, depletion and amortization	536	511	200	166
Segment Income	$ 924	$ 1,404	$ 363	$ 695

	Other		Total Upstream	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 81	$ 88	$ 2,812	$ 3,525
Expenses				
Production and mineral taxes	-	-	80	162
Transportation and selling	-	-	276	208
Operating	76	124	428	415
Depreciation, depletion and amortization	7	54	743	731
Segment Income (Loss)	$ (2)	$ (90)	$ 1,285	$ 2,009

Upstream Geographic and Product Information (Continuing Operations)
(For the three months ended December 31)

	Produced Gas					
	Canada		United States		Total	
	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties	$ 1,401	$ 1,852	$ 706	$ 1,041	$ 2,107	$ 2,893
Expenses						
Production and mineral taxes	11	20	54	127	65	147
Transportation and selling	66	72	66	48	132	120
Operating	166	144	76	64	242	208
Operating Cash Flow	$ 1,158	$ 1,616	$ 510	$ 802	$ 1,668	$ 2,418

	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties	$ 565	$ 479	$ 59	$ 65	$ 624	$ 544
Expenses						
Production and mineral taxes	9	9	6	6	15	15
Transportation and selling	144	88	-	-	144	88
Operating	110	83	-	-	110	83
Operating Cash Flow	$ 302	$ 299	$ 53	$ 59	$ 355	$ 358

	Other		Total Upstream	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 81	$ 88	$ 2,812	$ 3,525
Expenses				
Production and mineral taxes	-	-	80	162
Transportation and selling	-	-	276	208
Operating	76	124	428	415
Operating Cash Flow	$ 5	$ (36)	$ 2,028	$ 2,740

Results of Continuing Operations
(For the twelve months ended December 31)

	Upstream		Market Optimization	
	2006	2005	2006	2005

Revenues, Net of Royalties	$11,342	$10,772	$ 3,007	$ 4,267
Expenses				
Production and mineral taxes	349	453	-	-
Transportation and selling	1,054	832	16	13
Operating	1,605	1,351	62	85
Purchased product	-	-	2,862	4,159
Depreciation, depletion and amortization	3,025	2,688	12	8
Segment Income	$ 5,309	$ 5,448	$ 55	$ 2

	Corporate(*)		Consolidated	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 2,050	$ (466)	$16,399	$14,573
Expenses				
Production and mineral taxes	-	-	349	453
Transportation and selling	-	-	1,070	845
Operating	(12)	2	1,655	1,438
Purchased product	-	-	2,862	4,159
Depreciation, depletion and amortization	75	73	3,112	2,769
Segment Income (Loss)	$ 1,987	$ (541)	$ 7,351	$ 4,909
Administrative			271	268
Interest, net			396	524
Accretion of asset retirement obligation			50	37
Foreign exchange (gain) loss, net			14	(24)
Stock-based compensation - options			-	15
(Gain) on divestitures (Note 5)			(323)	-
			408	820
Net Earnings Before Income Tax			6,943	4,089
Income tax expense			1,892	1,260
Net Earnings From Continuing Operations			$ 5,051	$ 2,829

(*) For the twelve months ended December 31, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 14):

	2006	2005
Revenues, Net of Royalties - Corporate	$ 2,050	$ (466)
Operating Expenses and Other - Corporate	10	(3)
Total Unrealized Gain (Loss) on Risk Management before-tax - Continuing Operations	$ 2,060	$ (469)

Results of Continuing Operations

(For the twelve months ended December 31)

Upstream	Canada		United States	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 7,911	$ 7,312	$ 3,121	$ 3,177
Expenses				
Production and mineral taxes	116	104	233	349
Transportation and selling	806	650	248	182
Operating	1,029	826	283	212
Depreciation, depletion and amortization	2,142	1,927	848	682
Segment Income	$ 3,818	$ 3,805	$ 1,509	$ 1,752

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Other		Total Upstream	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 310	$ 283	$11,342	$10,772
Expenses				
Production and mineral taxes	-	-	349	453
Transportation and selling	-	-	1,054	832
Operating	293	313	1,605	1,351
Depreciation, depletion and amortization	35	79	3,025	2,688
Segment Income (Loss)	$ (18)	$ (109)	$ 5,309	$ 5,448

Upstream Geographic and Product Information (Continuing Operations)
(For the twelve months ended December 31)

	Produced Gas					
	Canada		United States		Total	
	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties	$ 5,440	$ 5,486	$ 2,854	$ 2,932	$ 8,294	$ 8,418
Expenses						
Production and mineral taxes	80	76	213	325	293	401
Transportation and selling	278	283	248	182	526	465
Operating	629	521	283	212	912	733
Operating Cash Flow	$ 4,453	$ 4,606	$ 2,110	$ 2,213	$ 6,563	$ 6,819

Transportation and selling for the United States includes a one time payment in the first quarter of 2006 of $14 million to terminate a long-term physical delivery contract.

	Oil & NGLs					
	Canada		United States		Total	
	2006	2005	2006	2005	2006	2005

Revenues, Net of Royalties	$ 2,471	$ 1,826	$ 267	$ 245	$ 2,738	$ 2,071
Expenses						
Production and mineral taxes	36	28	20	24	56	52
Transportation and selling	528	367	-	-	528	367
Operating	400	305	-	-	400	305
Operating Cash Flow	$ 1,507	$ 1,126	$ 247	$ 221	$ 1,754	$ 1,347

	Other		Total Upstream	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 310	$ 283	$11,342	$10,772
Expenses				
Production and mineral taxes	-	-	349	453
Transportation and selling	-	-	1,054	832
Operating	293	313	1,605	1,351
Operating Cash Flow	$ 17	$ (30)	$ 8,334	$ 8,136

Capital Expenditures (Continuing Operations)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Upstream Core Capital				
Canada	$ 849	$ 1,370	$ 4,015	$ 4,150
United States	315	633	2,061	1,982
Other Countries	24	31	75	70
	1,188	2,034	6,151	6,202
Upstream Acquisition Capital				
Canada	17	4	47	30
United States	16	227	284	418
	33	231	331	448
Market Optimization	4	68	44	197
Corporate	25	29	74	78
Total	$ 1,250	$ 2,362	$ 6,600	$ 6,925

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at December 31,		As at December 31,	
	2006	2005	2006	2005
Upstream	$ 27,781	$ 24,247	$ 32,299	$ 28,858
Market Optimization	154	371	469	597

Corporate	278	263	2,338	1,530
Assets of Discontinued Operations (Note 4)			-	3,163
Total	$ 28,213	$ 24,881	$ 35,106	$ 34,148

4. DISCONTINUED OPERATIONS

Midstream

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana's natural gas storage operations included the 100 percent interest in the AECO storage facility as well as facilities in the United States. On March 6, 2006, EnCana announced that it had reached an agreement to sell the gas storage operations for $1.5 billion. The sale, to a single purchaser, which was subject to closing conditions and applicable regulatory approvals closed in two stages. On May 12, 2006, the first stage of the sale was closed for proceeds of $1.3 billion. The second stage closed on November 17, 2006 following receipt of regulatory approvals. A total after-tax gain of $829 million was recorded.

On December 13, 2005, EnCana completed the sale of its Midstream natural gas liquids processing operations for total proceeds of $625 million (C$720 million). The natural gas liquids processing operations included various interests in a number of processing and related facilities as well as a marketing entity. An after-tax gain on sale of approximately $370 million was recorded.

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 included the 100 percent working interest in the Tarapoa Block, majority operating interest in Blocks 14, 17 and Shiripuno, the non-operated economic interest in relation to 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 was a shipper on the OCP Pipeline and paid commercial rates for tariffs. The majority of the Company's crude oil produced in Ecuador was sold to a single marketing company. Payments were secured by letters of credit from a major financial institution which has a high quality investment grade credit rating.

On February 28, 2006, EnCana completed the sale of its interest in its Ecuador operations for $1.4 billion before indemnifications which are discussed further in this note.

In accordance with Canadian generally accepted accounting principles, depreciation, depletion and amortization expense has not been recorded in the Consolidated Statement of Earnings for 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 December 31,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties	$ -	$ 242	$ -	$ -	$ 5	$ 645	$ 5	$ 887
Expenses								
Production and								

mineral taxes	-	30	-	-	-	-	-	30
Transportation and selling	-	12	-	-	-	3	-	15
Operating	-	38	-	-	8	110	8	148
Purchased product	-	-	-	-	2	343	2	343
Depreciation, depletion and amortization	-	111	-	-	-	8	-	119
Administration	-	-	-	-	-	30	-	30
Interest, net	-	(2)	-	-	-	(1)	-	(3)
Foreign exchange (gain) loss, net	-	(4)	(1)	(37)	(1)	-	(2)	(41)
(Gain) loss on discontinuance	-	-	-	-	(41)	(364)	(41)	(364)
	-	185	(1)	(37)	(32)	129	(33)	277
Net Earnings Before Income Tax	-	57	1	37	37	516	38	610
Income tax expense	-	57	1	4	17	52	18	113
Net Earnings From Discontinued Operations	$ -	$ -	$ -	$ 33	$ 20	$ 464	$ 20	$ 497

	For the twelve months ended December 31,							
	Ecuador		United Kingdom		Midstream		Total	
	2006	2005	2006	2005	2006	2005	2006	2005
Revenues, Net of Royalties(*)	$ 200	$ 965	$ -	$ -	$ 482	$1,570	$ 682	$2,535
Expenses								
Production and mineral taxes	23	131	-	-	-	-	23	131
Transportation and selling	10	58	-	-	-	9	10	67
Operating	25	138	-	-	37	301	62	439
Purchased product	-	-	-	-	356	1,100	356	1,100
Depreciation, depletion and amortization	84	234	-	-	-	28	84	262
Administration	-	-	-	-	-	30	-	30
Interest, net	(2)	(2)	-	-	-	(2)	(2)	(4)
Accretion of asset retirement obligation	-	1	-	-	-	-	-	1
Foreign exchange (gain) loss, net	1	(4)	(1)	(40)	4	(2)	4	(46)

(Gain) loss on discontinuance	279	-	-	-	(807)	(364)	(528)	(364)
	420	556	(1)	(40)	(410)	1,100	9	1,616
Net Earnings (Loss) Before Income Tax	(220)	409	1	40	892	470	673	919
Income tax expense (recovery)	59	278	(4)	5	17	39	72	322
Net Earnings (Loss) From Discontinued Operations	$(279)	$ 131	$ 5	$ 35	$ 875	$ 431	$ 601	$ 597

(*) Revenues, net of royalties in Ecuador include realized losses of $1 million related to derivative financial instruments. In 2005, revenues, net of royalties included realized losses of $128 million.

Consolidated Balance Sheet

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

	As at							
	December 31, 2006				December 31, 2005			
	Ecuador	United Kingdom	Mid-stream	Total	Ecuador	United Kingdom	Mid-stream	Total
Assets								
Cash and cash equivalents	$ -	$ -	$ -	$ -	$ 207	$ 8	$ (7)	$ 208
Accounts receivable and accrued revenues	-	-	-	-	137	-	271	408
Risk management	-	-	-	-	-	-	21	21
Inventories	-	-	-	-	23	-	390	413
	-	-	-	-	367	8	675	1,050
Property, plant and equipment, net	-	-	-	-	1,166	-	520	1,686
Investments and other assets	-	-	-	-	360	-	-	360
Goodwill	-	-	-	-	-	-	67	67
	$ -	$ -	$ -	$ -	$1,893	$ 8	$1,262	$3,163
Liabilities								
Accounts payable and accrued liabilities	$ -	$ -	$ -	$ -	$ 91	$ 27	$ 49	$ 167
Income tax payable	-	-	-	-	184	6	40	230

Risk management	-	-	-	-	-	-	41	41
	-	-	-	-	275	33	130	438
Asset retirement obligation	-	-	-	-	21	-	-	21
Future income taxes (recovery)	-	-	-	-	162	(2)	86	246
	-	-	-	-	458	31	216	705
Net Assets of Discontinued Operations	$ -	$ -	$ -	$ -	$1,435	$ (23)	$1,046	$2,458

Contingencies

EnCana agreed to indemnify the purchaser of its Ecuador interests against losses that may arise in certain circumstances which are defined in the share sale agreements. The obligation to indemnify will arise should losses exceed amounts specified in the sale agreements and is limited to maximum amounts which are set forth in the share sale agreements.

During the second quarter of 2006, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator which is an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. The purchaser requested payment and EnCana paid the maximum amount in the third quarter, calculated in accordance with the terms of the agreements, of approximately $265 million. EnCana does not expect that any further significant indemnification payments relating to any other business matters addressed in the share sale agreements will be required to be made to the purchaser.

5. DIVESTITURES

Total proceeds received on sale of assets and investments was $689 million (2005 - $2,523 million) as described below:

Upstream

In 2006, the Company has completed the divestiture of mature conventional oil and natural gas assets for proceeds of $78 million (2005 - $471 million).

In August 2006, the Company completed the sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil for approximately $367 million which resulted in a gain on sale of $304 million. After recording income tax of $49 million, EnCana recorded an after-tax gain of $255 million.

In May 2005, 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 $578 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.

Market Optimization

In February 2006, the Company sold its investment in Entrega Gas Pipeline LLC for approximately $244 million which resulted in a gain on sale of $17 million.

Notes to Consolidated Financial Statements (unaudited)
(All amounts in $ millions unless otherwise specified)

6. INTEREST, NET

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005

Interest Expense - Long-Term Debt	$ 97	$ 107	$ 366	$ 417
Early Retirement of Long-Term Debt	-	-	-	121
Interest Expense - Other	57	6	76	18
Interest Income	(12)	(9)	(46)	(32)
	$ 142	$ 104	$ 396	$ 524

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Unrealized Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt Issued from Canada	$ 155	$ 27	$ -	$ (113)
Other Foreign Exchange (Gain) Loss	17	10	14	89
	$ 172	$ 37	$ 14	$ (24)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Current				
Canada	$ 70	$ 205	$ 764	$ 493
United States	41	(25)	128	719
Other	2	(2)	50	(8)
Total Current Tax	113	178	942	1,204
Future	260	717	1,407	56
Future Tax Rate Reductions	-	-	(457)	-
	$ 373	$ 895	$ 1,892	$ 1,260

Included in current tax for 2006 is $49 million related to the sale of assets in Brazil (2005 - $578 million related to the sale of the Gulf of Mexico assets).

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Net Earnings Before Income Tax	$ 1,016	$ 2,764	$ 6,943	$ 4,089
Canadian Statutory Rate	34.7%	37.9%	34.7%	37.9%
Expected Income Tax	352	1,048	2,407	1,550

Effect on Taxes Resulting from:				
Non-deductible Canadian Crown payments	22	68	97	207
Canadian resource allowance	2	(87)	(16)	(202)
Statutory and other rate differences	(18)	(124)	(98)	(235)
Effect of tax rate changes(*)	-	-	(457)	-
Non-taxable capital (gains) losses	29	3	(1)	(24)
Tax basis retained on divestitures	-	-	-	(68)
Large corporations tax	-	1	-	25
Other	(14)	(14)	(40)	7
	$ 373	$ 895	$ 1,892	$ 1,260
Effective Tax Rate	36.7%	32.4%	27.3%	30.8%

(*) During the second quarter of 2006, the Canadian federal and Alberta governments substantively enacted income tax rate reductions.

9. LONG-TERM DEBT

	As at December 31, 2006	As at December 31, 2005
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	$ 1,456	$ 1,425
Unsecured notes	793	793
	2,249	2,218
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	104	-
Unsecured notes	4,421	4,494
	4,525	4,494
Increase in Value of Debt Acquired(*)	60	64
Current Portion of Long-Term Debt	(257)	(73)
	$ 6,577	$ 6,703

(*) 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 21 years.

10. 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 December 31, 2006	As at December 31, 2005
Asset Retirement Obligation, Beginning of Year	$ 816	$ 611

Liabilities Incurred	68	77
Liabilities Settled	(51)	(42)
Liabilities Divested	-	(23)
Change in Estimated Future Cash Flows	172	135
Accretion Expense	50	37
Other	(4)	21
Asset Retirement Obligation, End of Year	$ 1,051	$ 816

11. SHARE CAPITAL

	December 31, 2006		December 31, 2005	
(millions)	Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year	854.9	$ 5,131	900.6	$ 5,299
Common Shares Issued under Option Plans	8.6	179	15.0	283
Stock-based Compensation	-	11	-	11
Common Shares Purchased	(85.6)	(734)	(60.7)	(462)
Common Shares Outstanding, End of Year	777.9	$ 4,587	854.9	$ 5,131

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

In 2006, the Company purchased 85.6 million Common Shares for total consideration of approximately $4,219 million. Of the amount paid, $734 million was charged to Share capital and $3,485 million was charged to Retained earnings.

EnCana has received regulatory approval each year under Canadian securities laws to purchase Common Shares under five consecutive Normal Course Issuer Bids ("Bids"). EnCana is entitled to purchase, for cancellation, up to approximately 80.2 million Common Shares under the renewed Bid which commenced on November 6, 2006 and terminates on November 5, 2007.

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 date granted. 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 December 31, 2006. Information related to TSAR's is included in Note 12.

	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	20.7	23.36
Exercised	(8.6)	23.60
Forfeited	(0.3)	23.80

Outstanding, End of Year	11.8	23.17
Exercisable, End of Year	11.8	23.17

	Outstanding Options			Exercisable Options	
Range of Exercise Price (C$)	Number of Options Outstanding (millions)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Number of Options Outstanding (millions)	Weighted Average Exercise Price (C$)
11.00 to 16.99	0.8	2.3	11.89	0.8	11.89
17.00 to 22.99	0.2	1.0	22.32	0.2	22.32
23.00 to 23.99	5.4	1.3	23.87	5.4	23.87
24.00 to 24.99	5.2	0.4	24.19	5.2	24.19
25.00 to 25.99	0.2	1.7	25.58	0.2	25.58
	11.8	1.0	23.17	11.8	23.17

At December 31, 2006, the balance in Paid in surplus relates to stock-based compensation programs.

12. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at December 31, 2006. Additional information is contained in Note 15 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2005.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Current Service Cost	$ 6	$ 6	$ 16	$ 11
Interest Cost	4	6	17	16
Expected Return on Plan Assets	(4)	(5)	(16)	(14)
Expected Actuarial Loss on Accrued Benefit Obligation	2	3	6	5
Expected Amortization of Past Service Costs	1	1	2	2
Amortization of Transitional Obligation	-	(1)	(1)	(2)
Expense for Defined Contribution Plan	8	6	28	22
Net Benefit Plan Expense	$ 17	$ 16	$ 52	$ 40

For the year ended December 31, 2006, contributions of $9 million were made to the defined benefit pension plans.

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

The following table summarizes the information about SAR's at December 31, 2006:

Weighted Average

	Outstanding SAR's	Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	246,739	23.13
Exercised	(246,739)	23.13
Outstanding, End of Year	-	-
Exercisable, End of Year	-	-
U.S. Dollar Denominated (US$)		
Outstanding, Beginning of Year	319,511	14.33
Exercised	(317,423)	14.33
Outstanding, End of Year	2,088	14.21
Exercisable, End of Year	2,088	14.21

For the year ended December 31, 2006, EnCana has recorded a reduction in compensation costs of $1 million related to the outstanding SAR's (2005 - costs of $17 million).

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

The following table summarizes the information about stock options with Tandem SAR's attached at December 31, 2006:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	8,403,967	38.41
Granted	11,180,800	49.01
Exercised - SAR's	(700,418)	34.54
Exercised - Options	(32,948)	34.46
Forfeited	(1,575,210)	43.21
Outstanding, End of Year	17,276,191	44.99
Exercisable, End of Year	1,971,467	38.31

For the year ended December 31, 2006, EnCana recorded compensation costs of $52 million related to the outstanding TSAR's (2005 - $60 million).

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

The following table summarizes the information about DSU's at December 31, 2006:

	Outstanding DSU's	Average Share Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	836,561	26.81
Granted, Directors	70,000	56.71
Exercised	(52,562)	27.92
Units, in Lieu of Dividends	12,578	54.69
Outstanding, End of Year	866,577	29.56

Exercisable, End of Year	866,577	29.56

For the year ended December 31, 2006, EnCana recorded compensation costs of $5 million related to the outstanding DSU's (2005 - $16 million).

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

The following table summarizes the information about PSU's at December 31, 2006:

	Outstanding PSU's	Average Share Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	4,704,348	30.65
Granted	36,599	54.82
Paid out	(239,794)	23.26
Forfeited	(309,313)	31.35
Outstanding, End of Year	4,191,840	31.24
U.S. Dollar Denominated (US$)		
Outstanding, Beginning of Year	739,649	25.22
Granted	4,860	48.07
Forfeited	(170,020)	24.13
Outstanding, End of Year	574,489	25.74

For the year ended December 31, 2006, EnCana recorded compensation costs of $27 million related to the outstanding PSU's (2005 - $91 million).

At December 31, 2006, EnCana has approximately 5.5 million Common Shares held in trust for issuance upon vesting of the PSU's (2005 - 5.5 million).

13. PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

	Three Months Ended					Twelve Months Ended	
	March 31,	June 30,	September 30,	December 31,		December 31,	
(millions)	2006	2006	2006	2006	2005	2006	2005
Weighted Average Common Shares Outstanding - Basic	847.9	829.6	809.7	792.5	854.4	819.9	868.3
Effect of Dilutive Securities	16.9	15.5	14.6	13.9	18.1	16.6	20.9
Weighted Average Common Shares Outstanding - Diluted	864.8	845.1	824.3	806.4	872.5	836.5	889.2

14. 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 Gain (Loss) on Risk Management Activities

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

	Realized Gain (Loss)			
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 240	$ (355)	$ 393	$ (684)
Operating Expenses and Other	1	14	5	31
Gain (Loss) on Risk Management - Continuing Operations	241	(341)	398	(653)
Gain (Loss) on Risk Management - Discontinued Operations	8	(44)	12	(155)
	$ 249	$ (385)	$ 410	$ (808)

	Unrealized Gain (Loss)			
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2006	2005	2006	2005
Revenues, Net of Royalties	$ 129	$ 991	$ 2,050	$ (466)
Operating Expenses and Other	12	(6)	10	(3)
Gain (Loss) on Risk Management - Continuing Operations	141	985	2,060	(469)
Gain (Loss) on Risk Management - Discontinued Operations	(7)	139	20	50
	$ 134	$ 1,124	$ 2,080	$ (419)

Amounts Recognized on Transition

Upon initial adoption of the current accounting policy for risk management instruments 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.

At December 31, 2006, a net unrealized gain of approximately $16 million remains to be recognized over the next two years.

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2006 to December 31, 2006:

	Fair Market Value	Total Unrealized Gain (Loss)

Fair Value of Contracts, Beginning of Year	$ (640)	$ -
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During 2006	2,466	2,466
Fair Value of Contracts in Place at Transition that Expired During 2006	-	24
Fair Value of Contracts Realized During 2006	(410)	(410)
Fair Value of Contracts Outstanding	$ 1,416	$ 2,080
Unamortized Premiums Paid on Options	104	
Fair Value of Contracts and Premiums Paid, End of Year	$ 1,520	
Amounts Allocated to Continuing Operations	$ 1,520	$ 2,060
Amounts Allocated to Discontinued Operations	-	20
	$ 1,520	$ 2,080

At December 31, 2006, the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at December 31, 2006
Risk Management	
Current asset	$ 1,403
Long-term asset	133
Current liability	14
Long-term liability	2
Net Risk Management Asset - Continuing Operations	$ 1,520

A summary of all unrealized estimated fair value financial positions is as follows:

	As at December 31, 2006
Commodity Price Risk	
Natural gas	$ 1,431
Crude oil	74
Power	13
Interest Rate Risk	4
Credit Derivatives	(2)
Total Fair Value Positions	$ 1,520

Information with respect to credit derivatives and interest rate risk contracts in place at December 31, 2005 is disclosed in Note 16 to the Company's annual audited Consolidated Financial Statements. New power contracts have been entered into at December 31, 2006, which are described further in this note.

Natural Gas

At December 31, 2006, the Company's gas risk management activities from financial contracts had an unrealized gain of $1,410 million and a fair market value position of $1,431 million. The contracts were as follows:

	Notional	Fair

	Volumes (MMcf/d)	Term	Average Price	Market Value
Sales Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	1,487	2007	8.56 US$/Mcf	$ 861
Other	8	2007	8.97 US$/Mcf	7
NYMEX Fixed Price	222	2008	8.45 US$/Mcf	34
Options				
Purchased NYMEX Put Options	240	2007	6.00 US$/Mcf	15
Basis Contracts				
Fixed NYMEX to AECO Basis	747	2007	(0.72) US$/Mcf	39
Fixed NYMEX to Rockies Basis	538	2007	(0.65) US$/Mcf	223
Fixed NYMEX to CIG Basis	390	2007	(0.76) US$/Mcf	144
Fixed Rockies to CIG Basis	12	2007	(0.10) US$/Mcf	(1)
Fixed NYMEX to AECO Basis	191	2008	(0.78) US$/Mcf	10
Fixed NYMEX to Rockies Basis	162	2008	(0.59) US$/Mcf	46
Fixed NYMEX to CIG Basis	60	2008	(0.67) US$/Mcf	15
Fixed NYMEX to Rockies Basis (NYMEX Adjusted)	329	2008	17% of NYMEX US$/Mcf	14
Fixed NYMEX to Mid-Continent Basis (NYMEX Adjusted)	120	2008	12% of NYMEX US$/Mcf	4
Fixed NYMEX to CIG Basis	20	2009	(0.71) US$/Mcf	1
Fixed NYMEX to AECO Basis	12	2010	(0.40) US$/Mcf	-
Purchase Contracts				
Fixed Price Contracts				
Other	8	2007	7.84 US$/Mcf	(4)
				1,408
Other Financial Positions(*)				2
Total Unrealized Gain on Financial Contracts				1,410
Unamortized Premiums Paid on Options				21
Total Fair Value Positions				$ 1,431

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

Crude Oil

At December 31, 2006, the Company's oil risk management activities from financial contracts had an unrealized loss of $9 million and a fair market value position of $74 million. The contracts were as follows:

	Notional Volumes (bbls/d)	Term	Average Price	Fair Market Value
Fixed WTI NYMEX Price	34,500	2007	64.40 US$/bbl	$ (8)
Purchased WTI NYMEX Put Options	91,500	2007	55.34 US$/bbl	(1)

	(9)
Other Financial Positions(*)	-
Total Unrealized Loss on Financial Contracts	(9)
Unamortized Premiums Paid on Options	83
Total Fair Value Positions	$ 74

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

Power

In November 2006, the Company entered into two derivative contracts, commencing January 1, 2007 for a period of eleven years, to manage its electricity consumption costs. At December 31, 2006, these contracts had an unrealized gain of $13 million.

15. CONTINGENCIES

Legal Proceedings

The Company is involved in various legal claims associated with the normal course of operations. The Company believes it has made adequate provision for such legal claims.

Discontinued Merchant Energy Operations

During the period between 2003 and 2005, EnCana and its indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), along with other energy companies, were named as defendants in several lawsuits, some of which were class action lawsuits, relating to sales of natural gas from 1999 to 2002. The lawsuits allege that the defendants engaged in a conspiracy with unnamed competitors in the natural gas markets in California in violation of U.S. and California anti-trust and unfair competition laws.

Without admitting any liability in the lawsuits, WD agreed to settle all of the class action lawsuits in both state and federal court, for payment, of $20.5 million and $2.4 million, respectively. Court approval of the federal court class action settlement of $2.4 million is pending, court approval having been granted in the state court action. Also, as previously disclosed, without admitting any liability whatsoever, WD concluded settlements with the U.S. Commodity Futures Trading Commission ("CFTC") and of a previously disclosed consolidated class action lawsuit in the United Stated District Court in New York for $8.2 million.

The remaining lawsuits were commenced by individual plaintiffs, one of which is E. & J. Gallo Winery ("Gallo"). The Gallo lawsuit claims damages in excess of $30 million. The other remaining lawsuits do not specify the precise amount of damages claimed. California law allows for the possibility that the amount of damages assessed could be tripled.

The Company and WD intend to vigorously defend against the outstanding 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.

16. SUBSEQUENT EVENTS

Integrated Oilsands Business

On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American heavy oil business with ConocoPhillips which consists of an upstream and a downstream entity. In creating the integrated venture, EnCana contributed 50 percent of its Foster Creek and Christina Lake oilsands properties while ConocoPhillips contributed 50 percent of its Wood River and Borger refineries, located in Illinois and Texas respectively. On a go forward basis, EnCana will show a separate business

segment for the Integrated Oilsands business. In accordance with the Canadian generally accepted accounting principles, these entities will be accounted for using the proportionate consolidation method.

Sale of Chad Operations

On January 12, 2007, EnCana announced that it had completed the sale of its interests in Chad, properties that are considered to be in the pre-production stage, for proceeds of $203 million which will result in a gain on sale.

The Bow

On February 9, 2007, EnCana announced that it had completed the next phase in the development of The Bow office project with the sale of project assets and is entering into a 25 year lease agreement with a third party developer. EnCana expects to account for the agreement as a capital lease.