EnCana
energy for people

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EnCana Corporation 2006 Annual Report

strength stability

2006 ANNUAL REPORT

EnCana is uniquely positioned as an integrated North American resource play company. It is focused on creating long-term value by doing what it does best – developing unconventional natural gas and in-situ oilsands resources. The company's primary goal is to increase net asset value per share through disciplined capital investment in the development of its large unconventional resources; pursuit of strategic initiatives that unlock value through optimization of the company's enormous North American asset base; and return of free cash flow to shareholders through share purchases and dividends.

potential

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Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read with the audited Consolidated Financial Statements for the year ended December 31, 2006, as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2005. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this MD&A.

The Consolidated Financial Statements and comparative information have been prepared in United States dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and sales volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This MD&A is dated February 22, 2007.

Readers can find the definition of certain terms used in this MD&A in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to EnCana contained in the Advisories section located at the end of this MD&A.

EnCana's Business

EnCana is a leading North American unconventional natural gas and integrated oilsands company.

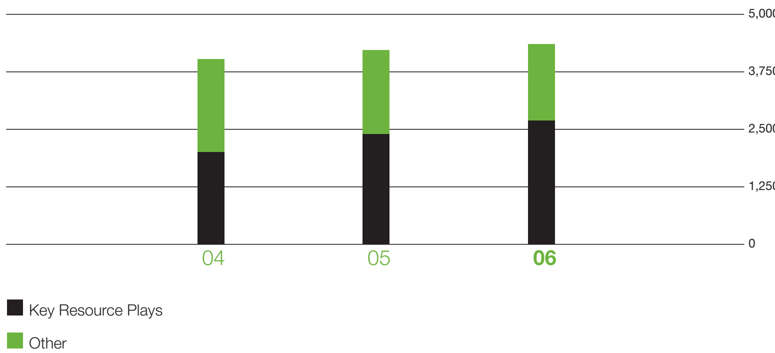
At December 31, 2006, EnCana operated two continuing businesses:

- Upstream includes the Company's exploration for, and development and production of, natural gas, crude oil and natural gas liquids ("NGLs") and other related activities. The majority of the Company's Upstream operations are located in Canada and the United States ("U.S."). International new ventures exploration is mainly focused on opportunities in Brazil, the Middle East, Greenland and France.
- Market Optimization is focused on enhancing the sale of EnCana's production. As part of these activities, Market Optimization buys and sells third party products to enhance EnCana's operating flexibility for transportation commitments, product type, delivery points and customer diversification.

2006 Overview

North American sales volumes

(MMcfe/d)



EnCana pursues predictable, profitable growth from a portfolio of long-life resource plays in Canada and the United States. In 2006 compared to 2005, EnCana:

- Grew total North American sales volumes 3 percent to 4,295 million cubic feet ("MMcf") of gas equivalent per day ("MMcfe/d");
- Grew natural gas sales by 4 percent to 3,367 MMcf/d;
- Reported a 16 percent decrease in natural gas prices to $6.25 per thousand cubic feet ("Mcf"). Realized natural gas prices, including the impact of financial hedging, averaged $6.72 per Mcf, a decrease of 6 percent;
- Reported average North American crude oil prices of $41.83 per barrel ("bbl"), an increase of 22 percent over 2005. Realized crude oil prices, including the impact of financial hedging, averaged $38.51 per bbl, an increase of 33 percent;
- Achieved sales of approximately 48,000 barrels per day ("bbls/d") at EnCana's three steam-assisted gravity drainage ("SAGD") projects (Foster Creek, Christina Lake and Senlac). Production at Foster Creek in 2006 was approximately 37,000 bbls/d compared to approximately 29,000 bbls/d in 2005;
- Increased production from key resource plays by 12 percent;
- Reported operating costs of $0.86 per Mcfe, a 21 percent increase mainly due to the higher U.S./Canadian dollar, increased industry activity and electricity costs;
- Completed the sale of EnCana's Ecuador assets for approximately $1.4 billion before indemnifications and both stages of the sale of EnCana's natural gas storage operations for approximately $1.5 billion;
- Completed the sale of its interest in the Chinook heavy oil discovery offshore Brazil for proceeds of approximately $367 million;
- Reported net earnings of $5,652 million (up 65 percent from 2005) mainly due to after-tax unrealized mark-to-market gains of $1,370 million and the after-tax gain on sale of the discontinued operations of $554 million;
- Purchased 85.6 million, or 10 percent, of its Common Shares at an average price of $49.26 per share under the Normal Course Issuer Bid ("NCIB") for a total cost of $4.2 billion; and
- Reduced Net Debt to Capitalization to 27 percent from 33 percent and Net Debt to Adjusted EBITDA to 0.6x from 1.1x at December 31, 2005.

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 its Foster Creek and Christina Lake oilsands properties, while ConocoPhillips contributed its Wood River and Borger refineries located in Illinois and Texas, respectively.

Business Environment

NATURAL GAS

Natural Gas Price Benchmarks Year Ended December 31 (Average for the period)	2006	2006 vs 2005	2005	2005 vs 2004	2004
AECO Price (C$/Mcf)	**$ 6.98**	**-18%**	$ 8.48	25%	$ 6.79
NYMEX Price ($/MMBtu)	**7.22**	**-16%**	8.62	40%	6.14
Rockies (Opal) Price ($/MMBtu)	**5.65**	**-19%**	6.96	33%	5.23
AECO/NYMEX Basis Differential ($/MMBtu)	**1.06**	**-33%**	1.59	75%	0.91
Rockies/NYMEX Basis Differential ($/MMBtu)	**1.57**	**-5%**	1.66	82%	0.91

NYMEX gas prices decreased in 2006 due to:

- a warmer than normal January and February;
- an aggressive industry drilling program that increased U.S. supply;
- an uneventful hurricane season compared to expectations and 2005; and
- a warmer than normal December.

All of the above contributed to an increase in industry levels of natural gas in storage throughout the year. Natural gas in storage for industry ended 2006 at 408 billion cubic feet ("Bcf") above the five year average.

The lower average AECO gas price in 2006 is attributed to the decrease in the NYMEX gas price and a stronger Canadian dollar partially offset by the narrowing of the AECO/NYMEX basis differential. A lower average Rockies (Opal) gas price in 2006 resulted from a lower NYMEX gas price partially offset by a reduced Rockies/NYMEX basis differential. Increased demand in the Rockies region during the second half of 2006 relieved some of the pressure that supply growth in the Rockies had exerted on an already highly utilized pipeline grid. This allowed the Rockies basis differential to narrow in 2006 compared to 2005. However, continued supply growth in the Rockies is expected to put further pressure on Rockies basis in the future. Until the Rockies Express Pipeline comes into service, expected in early 2008, EnCana has taken steps to mitigate its projected Rockies price risk from the impact of further deterioration in the Rockies basis differential through the use of financial basis hedges, the details of which are disclosed in Note 16 of the Consolidated Financial Statements.

CRUDE OIL

Crude Oil Price Benchmarks Year Ended December 31 (Average for the period ($/bbl))	2006	2006 vs 2005	2005	2005 vs 2004	2004 (1)
WTI	**$ 66.25**	**17%**	$ 56.70	37%	$ 41.47
WCS	**44.69**	**23%**	36.39	—	n/a
Differential – WTI/WCS	**21.56**	**6%**	20.31	—	n/a

(1) WCS was first posted by EnCana in October 2004, thus there is no annual average rate for WCS or WTI/WCS differential available for 2004.

Concerns over Iran's nuclear program, Nigerian production shut-in due to militant attacks, ongoing instability in Iraq and a lack of U.S. gasoline supply combined to propel the West Texas Intermediate ("WTI") price above the $70 per bbl level for most of the second and third quarters. By the end of 2006, WTI prices had fallen back to the $60 per bbl level as overall crude oil and refined product market balances continued to demonstrate there was adequate supplies of crude oil.

Canadian heavy oil differentials were comparable with 2005 owing to strength in asphalt and residual fuel oil markets supporting prices for Canadian heavy crude oil. The Western Canadian Select ("WCS") average sales price was 67 percent of WTI for 2006 compared to 64 percent of WTI in 2005.

U.S./CANADIAN DOLLAR EXCHANGE RATES

The impacts of currency fluctuations on EnCana's results should be considered when analyzing the Consolidated Financial Statements. The value of the Canadian dollar compared to the U.S. dollar increased by 6.9 percent, or $0.057, to an average of US$0.882 in 2006 from an average of US$0.825 in 2005, which was approximately 7.4 percent, or $0.057, higher than the 2004 average.

As a result, EnCana reported an additional $5.70 of costs for every one hundred Canadian dollars spent on capital projects, operating expenses and administrative expenses in 2006 relative to 2005. However, revenues were relatively unaffected by fluctuations in the U.S./Canadian dollar exchange rate because the commodity prices received by EnCana are largely based in U.S. dollars or in Canadian dollars at prices that are closely tied to the value of the U.S. dollar.

U.S./Canadian Dollar Exchange Rates

Year Ended December 31	**2006**	2005	2004
Average U.S./Canadian dollar exchange rate	**$ 0.882**	$ 0.825	$ 0.768
Average U.S./Canadian dollar exchange rate for prior year	**$ 0.825**	$ 0.768	$ 0.716
Increase in reported capital, operating and administrative expenditures caused solely by fluctuations in exchange rates, for every hundred Canadian dollars spent	**$ 5.70**	$ 5.70	$ 5.20

Acquisitions and Divestitures

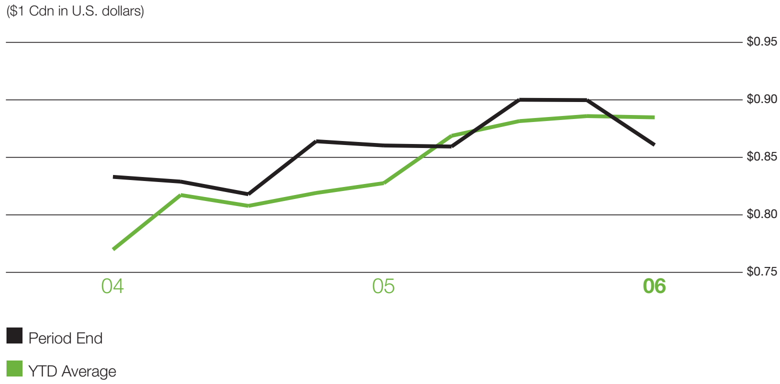
In keeping with EnCana's North American resource play strategy, the Company completed the following significant divestitures in 2006:

- The sale of the Entrega Pipeline, located in Colorado, on February 23 for approximately $244 million;
- The sale of its interests in Ecuador on February 28 for approximately $1.4 billion before indemnifications, which is discussed in Note 4 to the Consolidated Financial Statements;
- The sale of its natural gas storage operations in Canada and the U.S. in two separate transactions with a single purchaser for total proceeds of approximately $1.5 billion resulting in an after-tax gain on sale of $829 million; and
- The sale of its 50 percent interest in the Chinook heavy oil discovery offshore Brazil on August 16 for approximately $367 million, resulting in an after-tax gain on sale of $255 million.

Proceeds from these divestitures were directed primarily to the purchase of shares under EnCana's NCIB and debt repayments.

US/Canadian dollar exchange rates

($1 Cdn in U.S. dollars)



Consolidated Financial Results

Year Ended December 31 ($ millions, except per share (1) amounts)	2006	2006 vs 2005	2005	2005 vs 2004	2004
Total Consolidated					
Cash Flow (2)	**$ 7,161**	**-4%**	$ 7,426	49%	$ 4,980
per share – diluted	**8.56**	**3%**	8.35	57%	5.32
Net Earnings	**5,652**	**65%**	3,426	-2%	3,513
per share – basic	**6.89**	**74%**	3.95	3%	3.82
per share – diluted	**6.76**	**76%**	3.85	3%	3.75
Operating Earnings (3)	**3,271**	**1%**	3,241	64%	1,976
per share – diluted	**3.91**	**7%**	3.64	73%	2.11
Total Assets	**35,106**	**3%**	34,148	9%	31,213
Long-Term Debt	**6,577**	**-2%**	6,703	-13%	7,742
Cash Dividends	**304**	**28%**	238	30%	183
Continuing Operations					
Cash Flow from Continuing Operations (2)	**7,043**	**1%**	6,962	55%	4,502
Net Earnings from Continuing Operations	**5,051**	**79%**	2,829	35%	2,093
per share – basic	**6.16**	**89%**	3.26	44%	2.27
per share – diluted	**6.04**	**90%**	3.18	42%	2.24
Operating Earnings from Continuing Operations (3)	**3,237**	**6%**	3,048	63%	1,872
Revenues, Net of Royalties	**16,399**	**13%**	14,573	39%	10,491

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

(2) 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.

(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are described and discussed under "Operating Earnings", all of which are defined on the Consolidated Statement of Cash Flows.

CASH FLOW

While cash flow measures are considered non-GAAP, they are commonly used in the oil and gas industry and are used by EnCana to assist management and investors in measuring the Company's ability to finance capital programs and meet financial obligations.

2006 vs 2005

EnCana's 2006 cash flow was $7,161 million, a decrease of 4 percent from 2005 mainly due to the decline in cash flow from discontinued operations of $346 million year over year.

Cash flow from continuing operations in 2006 was $7,043 million (2005 – $6,962 million).

The increase in cash flow from continuing operations was positively impacted by:

- Average North American liquids prices, excluding financial hedges, increased 21 percent to $43.71 per bbl in 2006 compared to $36.17 per bbl in 2005;
- North American natural gas sales volumes in 2006 increased 4 percent to 3,367 MMcf/d from 3,227 MMcf/d in 2005; and
- Realized financial natural gas and crude oil commodity hedging gains were $263 million after-tax (natural gas $386 million gain; crude oil and other $123 million loss) in 2006 compared with losses of $441 million after-tax (natural gas $261 million loss; crude oil and other $180 million loss) in 2005.

The increase in cash flow from continuing operations was negatively impacted by:

- Average North American natural gas prices, excluding financial hedges, decreased 16 percent to $6.25 per Mcf in 2006 compared to $7.46 per Mcf in 2005;
- Operating expenses, which increased 15 percent to $1,655 million in 2006 compared with $1,438 million in 2005; and
- The current tax provision, excluding income tax on the sale of the Brazil assets, increased $267 million to $893 million in 2006 compared to $626 million in 2005, excluding income tax on the sale of the Gulf of Mexico assets.

2005 vs 2004

EnCana's 2005 cash flow was $7,426 million, an increase of $2,446 million or 49 percent from 2004. This increase reflects higher commodity prices in 2005 partially reduced by increased costs. EnCana's discontinued operations contributed $464 million to cash flow compared with $478 million in 2004.

EnCana's 2005 cash flow from continuing operations was $6,962 million (2004 – $4,502 million), an increase of $2,460 million or 55 percent.

The increase in cash flow from continuing operations was positively impacted by:

- Average North American natural gas prices, excluding financial hedges, increased 36 percent to $7.46 per Mcf in 2005 compared to $5.47 per Mcf for 2004;
- North American natural gas sales volumes increased 9 percent to 3,227 MMcf/d; and
- Average North American liquids prices, excluding financial hedges, increased 26 percent to $36.17 per bbl in 2005 compared to $28.77 per bbl in 2004.

The increase in cash flow was negatively impacted by:

- Operating expenses, which increased 31 percent to $1,438 million in 2005 compared with $1,099 million in 2004;
- Interest expense, which increased $126 million to $524 million in 2005. Almost all of this increase represents the cost to redeem certain notes in 2005; and
- The current tax provision, excluding income tax on the sale of the Gulf of Mexico assets, increased $67 million to $626 million compared with $559 million in 2004.

Realized financial natural gas and crude oil commodity hedging losses were $441 million after-tax in 2005, relatively unchanged from $430 million after-tax in 2004.

NET EARNINGS

EnCana's 2006 net earnings were $5,652 million (2005 – $3,426 million). Net earnings for the year include unrealized after-tax mark-to-market gains of $1,370 million (2005 – after-tax losses of $277 million) and the effect of the tax rate reduction of $457 million (2005 – nil). Net earnings from discontinued operations increased slightly to $601 million, mainly due to the gain on sale of the gas storage assets in 2006 offset partially by the loss on sale of Ecuador assets (discussed in the Discontinued Operations section of this MD&A).

2006 vs 2005

EnCana's 2006 net earnings from continuing operations were $5,051 million, an increase of $2,222 million compared with 2005. In addition to the items affecting cash flow as detailed previously, significant items affecting net earnings were:

- Unrealized mark-to-market gains of $1,357 million after-tax (natural gas $1,256 million gain; crude oil and other $101 million gain) in 2006 compared with losses of $311 million after-tax (natural gas $326 million loss; crude oil and other $15 million gain) in 2005;
- A gain on sale of approximately $255 million after-tax from the sale of a 50 percent interest in the Chinook heavy oil discovery offshore Brazil; and
- An increase in depreciation, depletion and amortization ("DD&A") of $343 million as a result of the higher U.S./Canadian dollar, higher DD&A rates and increased sales volumes.

2005 vs 2004

EnCana's 2005 net earnings were $3,426 million (2004 – $3,513 million). Net earnings from discontinued operations decreased $823 million to $597 million; most of this decrease results from the 2005 after-tax gain of $370 million on the sale of substantially all of EnCana's natural gas processing business being less than the 2004 after-tax gain on the sale of EnCana's United Kingdom ("U.K.") operations.

EnCana's 2005 net earnings from continuing operations were $2,829 million, an increase of $736 million, or 35 percent compared with 2004. In addition to the items affecting cash flow as detailed previously, significant items affecting earnings were:

- An increase in DD&A of $390 million as a result of the higher U.S./Canadian dollar, higher DD&A rates and increased sales volumes; and
- Unrealized mark-to-market losses of $311 million after-tax in 2005 compared with losses of $117 million in 2004.

OPERATING EARNINGS

Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures that adjust net earnings and net earnings from continuing operations by non-operating items that Management believes reduce the comparability of the Company's underlying financial performance between periods. The following reconciliation of Operating Earnings and Operating Earnings from Continuing Operations has been prepared to provide investors with information that is more comparable between periods.

Summary of Total Operating Earnings

Year Ended December 31 ($ millions)	2006	2006 vs 2005	2005	2005 vs 2004	2004
Net Earnings, as reported	**$ 5,652**	**65%**	$ 3,426	-2%	$ 3,513
Add back (losses) and deduct gains:					
Unrealized mark-to-market accounting gain (loss), after-tax	**1,370**		(277)		(165)
Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**–**		92		229
Gain on sale of discontinued operations, after-tax	**554**		370		1,364
Future tax recovery due to tax rate reductions	**457**		—		109
Operating Earnings (2)(3)	**$ 3,271**	**1%**	$ 3,241	64%	$ 1,976

Year Ended December 31 ($ per Common Share – Diluted)	2006	2006 vs 2005	2005	2005 vs 2004	2004
Net Earnings, as reported	**$ 6.76**	**76%**	$ 3.85	3%	$ 3.75
Add back (losses) and deduct gains:					
Unrealized mark-to market accounting gain (loss), after-tax	**1.64**		(0.31)		(0.18)
Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**–**		0.10		0.24
Gain on sale of discontinued operations, after-tax	**0.66**		0.42		1.46
Future tax recovery due to tax rate reductions	**0.55**		—		0.12
Operating Earnings (2)(3)	**$ 3.91**	**7%**	$ 3.64	73%	$ 2.11

(1) 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 5 years.

(2) Operating Earnings is a non-GAAP measure that shows net earnings, excluding the after-tax gain or loss from the divestiture 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.

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

The 2006 operating earnings per share have increased mainly due to share purchases under the NCIB program.

Summary of Operating Earnings from Continuing Operations Year Ended December 31 ($ millions)	2006	2006 vs 2005	2005	2004 vs 2004	2004
Net Earnings from Continuing Operations, as reported	**$ 5,051**	**79%**	$ 2,829	35%	$2,093
Add back (losses) and deduct gains:					
Unrealized mark-to-market accounting gain (loss), after-tax	**1,357**		(311)		(117)
Unrealized foreign exchange gain on translation of Canadian issued U.S. dollar debt, after-tax (1)	**–**		92		229
Future tax recovery due to tax rate reductions	**457**		—		109
Operating Earnings from Continuing Operations (2)(3)	**$ 3,237**	**6%**	$ 3,048	63%	$ 1,872

(1) 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 5 years.

(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 – CONTINUING OPERATIONS

Upstream Operations

Financial Results from Continuing Operations

Year Ended December 31 ($ millions)	2006				2005				2004			
	Produced Gas	**Crude Oil and NGLs**	**Other**	**Total**	Produced Gas	Crude Oil and NGLs	Other	Total	Produced Gas	Crude Oil and NGLs	Other	Total
Revenues, Net of Royalties	**$ 8,294**	**$ 2,738**	**$ 310**	**$11,342**	$ 8,418	$ 2,071	$ 283	$10,772	$ 5,704	$ 1,552	$ 232	$ 7,488
Expenses												
Production and mineral taxes	**293**	**56**	**–**	**349**	401	52	—	453	270	41	—	311
Transportation and selling	**526**	**528**	**–**	**1,054**	465	367	—	832	416	288	—	704
Operating	**912**	**400**	**293**	**1,605**	733	305	313	1,351	519	285	222	1,026
Operating Cash Flow	**$ 6,563**	**$ 1,754**	**$ 17**	**$ 8,334**	$ 6,819	$ 1,347	$ (30)	$ 8,136	$ 4,499	$ 938	$ 10	$ 5,447
Depreciation, depletion and amortization				**3,025**				2,688				2,271
Segment Income				**$ 5,309**				$ 5,448				$ 3,176

Upstream Revenues

2006 vs 2005

Revenues, net of royalties, 2006 compared with 2005:

increased due to

- A 21 percent increase in North American liquids prices and a 4 percent increase in North American natural gas volumes; and
- Realized financial natural gas and crude oil commodity hedging gains of $397 million in 2006 compared to losses of $672 million for 2005;

were lower due to

- A 16 percent decrease in North American natural gas prices.

2005 vs 2004

Revenues, net of royalties, 2005 compared with 2004:

increased due to

- A 36 percent increase in natural gas prices combined with a 9 percent increase in natural gas sales volumes; and
- A 26 percent increase in liquids prices;

were lower due to

- A 6 percent decrease in liquids volumes mainly as a result of property divestitures in the first and third quarters of 2004 and in June 2005.

Realized financial natural gas and crude oil commodity hedging losses totaled $672 million in 2005, relatively unchanged from $669 million in 2004.

Revenue Variances for 2006 Compared to 2005 from Continuing Operations

Year Ended December 31 ($ millions)	2005 Revenues, Net of Royalties	Revenue Variances in: Price [1]	Revenue Variances in: Volume	**2006 Revenues, Net of Royalties**
Produced Gas				
Canada	$ 5,486	$ (178)	$ 132	**$ 5,440**
United States	2,932	(288)	210	**2,854**
Total Produced Gas	$ 8,418	$ (466)	$ 342	**$ 8,294**
Crude Oil and NGLs				
Canada	$ 1,826	$ 651	$ (6)	**$ 2,471**
United States	245	41	(19)	**267**
Total Crude Oil and NGLs	$ 2,071	$ 692	$ (25)	**$ 2,738**

(1) Includes the impact of realized financial hedging.

The increase in liquids sales prices and natural gas realized financial commodity hedging gains account for the majority of the approximately 5 percent increase in revenues, net of royalties, in 2006 compared with 2005. The balance of the increase in revenues results from an increase in natural gas sales volumes.

Produced gas volumes in Canada increased 2 percent in 2006, mainly due to drilling success in the key resource plays of Coalbed Methane Integrated ("CBM") in central and southern Alberta, Cutbank Ridge in northeast British Columbia and Bighorn in west-central Alberta and additional well tie-ins and recompletions in several areas. CBM is the commingled gas volumes from the coal and sand intervals based on regulatory approval. Offsetting the increase were unscheduled maintenance, natural declines, planned turnarounds and weather related delays for the Shallow Gas key resource play and conventional properties, which resulted in lower production volumes.

Produced gas volumes in the U.S. increased 8 percent in 2006 as a result of drilling success at Fort Worth, Jonah, Piceance and East Texas as well as the impact of property acquisitions in the Fort Worth Basin in late 2005.

North American crude oil and NGLs volumes were basically unchanged as a result of production increases at Foster Creek offset by the Pelican Lake royalty payout, lower production due to unscheduled maintenance, delays in capital programs in southern Alberta and natural declines. EnCana's Pelican Lake property reached payout in April 2006, which increased the royalty payments to the Government of Alberta and reduced EnCana's net revenue interest crude oil volumes by approximately 6,000 bbls/d at the point of payout.

Upstream Sales Volumes

Sales Volumes Year Ended December 31	2006	2006 vs 2005	2005	2005 vs 2004	2004
Produced Gas (MMcf/d)	**3,367**	**4%**	3,227	9%	2,968
Crude Oil (bbls/d)	**130,497**	**—**	130,418	-7%	140,379
NGLs (bbls/d)	**24,207**	**-5%**	25,582	-2%	26,038
Continuing Operations (MMcfe/d) (1)	**4,295**	**3%**	4,163	5%	3,966
Discontinued Operations					
Ecuador (bbls/d) (2)	**12,366**	**-83%**	71,065	-9%	77,993
United Kingdom (BOE/d) (3)	**—**	**—**	—	-100%	20,973
Discontinued Operations (MMcfe/d) (1)	**74**	**-83%**	426	-28%	594
Total (MMcfe/d) (1)	**4,369**	**-5%**	4,589	1%	4,560

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.
(2) As the Ecuador sale occurred on February 28, 2006 only two months of volumes are included in 2006.
(3) Includes natural gas and liquids (converted to BOE).

Sales volumes from continuing operations in 2006 increased 3 percent or 132 MMcfe/d from 2005 due to:

- Production from EnCana's key resource plays increased 12 percent;
- Drilling success in the key resource gas plays of CBM, Cutbank Ridge, Bighorn, Fort Worth, Jonah, Piceance and East Texas offset somewhat by unscheduled maintenance, natural declines, planned turnarounds and weather related delays for the Shallow Gas key resource play and conventional properties; and
- Expansion of Foster Creek facilities partially offset by the Pelican Lake royalty payout in April 2006 and natural declines for conventional properties.

Key Resource Plays	Daily Production					Drilling Activity (number of net wells drilled)		
	2006	2006 vs 2005	2005	2005 vs 2004	2004	2006	2005	2004
Natural Gas (MMcf/d)								
Jonah	**464**	**7%**	435	12%	389	**163**	104	70
Piceance	**326**	**6%**	307	18%	261	**220**	266	250
East Texas	**99**	**10%**	90	80%	50	**59**	84	50
Fort Worth	**101**	**44%**	70	159%	27	**97**	59	36
Greater Sierra	**213**	**-3%**	219	-5%	230	**115**	164	187
Cutbank Ridge	**170**	**85%**	92	130%	40	**116**	135	50
Bighorn	**91**	**65%**	55	31%	42	**52**	51	20
CBM Integrated (1)	**194**	**73%**	112	300%	28	**729**	1,245	1,086
Shallow Gas	**600**	**-4%**	625	6%	592	**1,164**	1,267	1,552
Oil (Mbbls/d)								
Foster Creek	**37**	**28%**	29	—	29	**6**	39	11
Christina Lake	**6**	**20%**	5	25%	4	**2**	—	2
Pelican Lake	**24**	**-8%**	26	37%	19	**—**	52	92
Total (MMcfe/d)	**2,656**	**12%**	2,366	20%	1,971	**2,723**	3,466	3,406

(1) CBM Integrated's 2005 and 2004 volumes and net wells drilled restated to report commingled gas volumes from the coal and sand intervals based on regulatory approval.

Per Unit Results – Produced Gas

Year Ended December 31	Canada					United States				
($ per thousand cubic feet)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Price (1)	**$ 6.20**	**-15%**	$ 7.27	36%	$ 5.34	**$ 6.35**	**-19%**	$ 7.82	35%	$ 5.79
Expenses										
Production and mineral taxes	**0.10**	**–**	0.10	25%	0.08	**0.49**	**-40%**	0.81	25%	0.65
Transportation and selling	**0.35**	**-3%**	0.36	-8%	0.39	**0.54**	**17%**	0.46	48%	0.31
Operating	**0.79**	**18%**	0.67	29%	0.52	**0.65**	**23%**	0.53	43%	0.37
Netback	**$ 4.96**	**-19%**	$ 6.14	41%	$ 4.35	**$ 4.67**	**-22%**	$ 6.02	35%	$ 4.46
Gas Sales Volumes (MMcf/d)	**2,185**	**2%**	2,132	2%	2,099	**1,182**	**8%**	1,095	26%	869

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

EnCana's North American natural gas price for 2006, excluding the impact of financial hedges, was $6.25 per Mcf, a decrease of 16 percent compared to 2005, which is consistent with the decline in the AECO price of 18 percent and the NYMEX price of 16 percent. North American realized financial commodity hedging gains on natural gas for 2006 were approximately $584 million or $0.47 per Mcf compared to losses of approximately $377 million or $0.32 per Mcf in 2005. The hedging gains in 2006 were a result of put hedging instruments transacted at higher price levels than in 2005, coupled with a decline in North American natural gas prices in 2006 compared to 2005.

Natural gas per unit production and mineral taxes, which are generally calculated as a percentage of revenues, have remained flat in Canada for 2006 mainly due to lower natural gas prices offset partially by the higher U.S./Canadian dollar. Natural gas per unit production and mineral taxes in the U.S. decreased $0.32 per Mcf or 40 percent in 2006 mainly as a result of a reduction in the effective production and severance tax rates for Colorado properties and lower natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased $0.08 per Mcf or 17 percent for 2006 primarily as a result of higher transportation costs on operated wells from Piceance, East Texas and certain Colorado properties.

Natural gas per unit operating expenses in Canada for 2006 were 18 percent or $0.12 per Mcf higher as a result of the higher U.S./Canadian dollar, increased industry activity, property taxes and lease rentals, electricity rates and salaries and benefits. Natural gas per unit operating expenses in the U.S. increased 23 percent or $0.12 per Mcf for 2006 mainly as a result of increased industry activity, chemicals, salaries, workovers and repairs and maintenance expenses. Increases in operating costs in both Canada and the U.S. were offset partially by lower long-term compensation costs in 2006 compared to 2005.

2005 vs 2004

EnCana's realized natural gas prices for 2005 were $7.46 per Mcf, an increase of 36 percent compared with 2004, which is consistent with the increase in the AECO price of 25 percent and the NYMEX price of 40 percent. North American realized financial commodity hedging losses on natural gas for 2005 were approximately $377 million or $0.32 per Mcf compared to losses of approximately $238 million or $0.22 per Mcf in 2004.

Natural gas per unit production and mineral taxes in the U.S. increased $0.16 per Mcf or 25 percent in 2005 as a result of higher natural gas prices.

Natural gas per unit transportation and selling costs for the U.S. increased 48 percent or $0.15 per Mcf for 2005 primarily as a result of marketing certain gas volumes downstream of the wellhead in 2005, which were marketed at the wellhead in 2004.

Canadian natural gas per unit operating expenses for 2005 were 29 percent or $0.15 per Mcf higher as a result of increased industry activity, the higher U.S./Canadian dollar, higher repairs and maintenance and long-term compensation expenses. Natural gas per unit operating expenses in the U.S. increased 43 percent or $0.16 per Mcf for 2005 mainly as a result of increased staffing levels, higher long-term compensation expenses, increased industry activity and higher workovers.

Per Unit Results – Crude Oil

Year Ended December 31

($ per barrel)	North America 2006	2006 vs 2005	2005	2005 vs 2004	2004
Price (1)	**$ 41.83**	**22%**	$ 34.15	22%	$ 27.92
Expenses					
Production and mineral taxes	**0.77**	**33%**	0.58	41%	0.41
Transportation and selling	**1.40**	**17%**	1.20	13%	1.06
Operating	**9.09**	**26%**	7.23	21%	6.00
Netback	**$ 30.57**	**22%**	$ 25.14	23%	$ 20.45
Crude Oil Sales Volumes (bbls/d)	**130,497**	**–**	130,418	-7%	140,379

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

The increase in EnCana's North American crude oil price for 2006, excluding the impact of financial hedges, reflects the 23 percent increase in the benchmark WCS crude oil price compared to 2005. North American realized financial commodity hedging losses on crude oil were approximately $187 million or $3.32 per bbl for 2006 compared to losses of approximately $295 million or $5.18 per bbl for 2005. The reduced hedging losses in 2006 were a result of fixed price and put hedging instruments transacted at higher price levels than in 2005, coupled with an increase in North American oil prices in 2006 compared to 2005.

Heavy oil sales in 2006 have increased slightly from 2005, representing approximately 66 percent of total oil sales in 2006 versus 64 percent of total oil sales in 2005. The percentage increase is a result of the increase in heavy oil production from Foster Creek, offset slightly by the Pelican Lake royalty payout in April 2006 and declining conventional production.

North American crude oil per unit production and mineral taxes increased 33 percent or $0.19 per bbl in 2006 primarily due to increased production from the Weyburn and Senlac properties in Saskatchewan, which are subject to freehold production tax and Saskatchewan resource tax, the higher U.S./Canadian dollar and the impact of higher overall prices.

North American crude oil per unit transportation and selling costs increased 17 percent or $0.20 per bbl in 2006 primarily due to a higher proportion of Canadian heavy crude oil volumes being delivered to the U.S. Gulf Coast to capture higher selling prices and the higher U.S./Canadian dollar. Crude oil transportation and selling costs also include costs of condensate purchased for blending of bitumen, totaling $458 million (2005 – $307 million; 2004 – $232 million), which are not included in the transportation and selling per unit calculations.

North American crude oil per unit operating costs for 2006 increased 26 percent or $1.86 per bbl mainly due to workovers at Foster Creek, the higher U.S./Canadian dollar, increased electricity rates, a prior period adjustment for a non-operated property, increased industry activity and lower production from Pelican Lake as a result of the royalty payout in the second quarter of 2006. The increased proportion of crude oil volumes from SAGD projects, which have higher operating costs compared to EnCana's other properties, also increased the overall crude oil per unit operating costs.

2005 vs 2004

The increase in the average crude oil price in 2005, excluding the impact of financial hedges, reflects the 37 percent increase in the benchmark WTI in 2005. This increase was partially offset by the increased WTI/Bow River crude oil price differential (up approximately 53 percent). North American realized financial commodity hedging losses on crude oil were approximately $295 million or $5.18 per bbl of liquids in 2005 compared to losses of approximately $431 million or $7.08 per bbl of liquids in 2004.

Heavy oil sales in 2005 increased to 64 percent of total oil sales from 60 percent in 2004. This increase was mainly due to an increase in heavy oil production from the Pelican Lake property combined with divestitures of non-core conventional assets in 2004 and 2005 that produced light/medium oil.

North American crude oil per unit production and mineral taxes increased by 41 percent or $0.17 per bbl in 2005 primarily due to the impact of higher prices.

The 2005 crude oil per unit transportation and selling expenses in North America increased 13 percent or $0.14 per bbl mainly due to the higher U.S./Canadian dollar and increased tariff rates as of July 2005.

North American crude oil per unit operating costs for 2005 increased 21 percent or $1.23 per bbl mainly due to the higher U.S./Canadian dollar, workovers, repairs and maintenance, fuel costs 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, increased the overall crude oil per unit operating costs.

Per Unit Results – NGLs

Year Ended December 31

	Canada					United States				
($ per barrel)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Price (1)	**$ 51.12**	**16%**	$ 44.24	41%	$ 31.43	**$ 56.33**	**16%**	$ 48.36	36%	$ 35.43
Expenses										
Production and mineral taxes	**—**	**—**	—	—	—	**4.19**	**-14%**	4.86	27%	3.82
Transportation and selling	**0.67**	**60%**	0.42	2%	0.41	**0.01**	**—**	0.01	—	—
Netback	**$ 50.45**	**15%**	$ 43.82	41%	$ 31.02	**$ 52.13**	**20%**	$ 43.49	38%	$ 31.61
NGLs Sales Volumes (bbls/d)	**11,713**	**-2%**	11,907	-11%	13,452	**12,494**	**-9%**	13,675	9%	12,586

(1) Excludes the impact of realized financial hedging.

2006 vs 2005

The increase in NGLs realized prices in 2006 compared to 2005 generally correlates with higher WTI oil prices.

NGLs per unit transportation and selling costs in Canada increased 60 percent or $0.25 per bbl in 2006 due to an increase in volumes being trucked and higher trucking rates due to inflation at Bighorn and certain B.C. properties.

U.S. NGLs per unit production and mineral taxes in the U.S. decreased 14 percent or $0.67 per bbl in 2006 mainly as a result of a reduction in the effective production and severance tax rates for Colorado properties.

U.S. NGLs sales volumes decreased 9 percent as a result of declines at certain Colorado properties that have a high liquids component.

2005 vs 2004

The increase in NGLs realized prices in 2005 generally correlates with increased WTI oil prices.

U.S. NGLs per unit production and mineral taxes for 2005 increased 27 percent or $1.04 per bbl as a result of the increase in NGLs prices.

Upstream Depreciation, Depletion and Amortization

2006 vs 2005

DD&A expenses in 2006 increased $337 million or 13 percent from 2005 due to:

- North American sales volumes increased 3 percent;
- Unit of production DD&A rates were $1.91 per Mcfe in 2006 compared to $1.72 per Mcfe in 2005. Rates were higher as a result of the higher U.S./Canadian dollar and an increase in future development costs partially reduced by the effect of the Gulf of Mexico sale in May 2005; and
- DD&A expense in 2006 included impairments of $6 million related to exploration prospects in the Middle East compared to $7 million in 2005.

2005 vs 2004

DD&A expenses in 2005 increased by $417 million or 18 percent from 2004 due to:

- North American sales volumes increased 5 percent;
- Unit of production DD&A rates were $1.72 per Mcfe in 2005 compared to $1.53 per Mcfe in 2004. Rates increased as a result of the higher U.S./Canadian dollar and increased future development costs reduced by the effect of the 2005 Gulf of Mexico sale; and
- DD&A expense in 2005 included impairments of $7 million related to exploration prospects in Yemen and other areas.

Market Optimization

Financial Results Year Ended December 31 ($ millions)	**2006**	**2006 vs 2005**	2005	2005 vs 2004	2004
Revenues	**$ 3,007**	**-30%**	$ 4,267	33%	$ 3,200
Expenses					
Transportation and selling	**16**	**23%**	13	-28%	18
Operating	**62**	**-27%**	85	15%	74
Purchased product	**2,862**	**-31%**	4,159	35%	3,092
Operating Cash Flow	**67**	**570%**	10	-38%	16
Depreciation, depletion and amortization	**12**	**50%**	8	-83%	47
Segment Income (Loss)	**$ 55**	**2,650%**	$ 2	106%	$ (31)

2006 vs 2005

Market Optimization results for 2006 include power generation income of $21 million (2005 – $1 million; 2004 – $(6) million) reflecting very high Alberta power pool prices realized by the Company's 100 percent owned Cavalier and 50 percent owned Balzac power plants.

On January 1, 2006, EnCana adopted Emerging Issues Task Force ("EITF") Abstract No. 04-13 – Accounting for Purchases and Sales of Inventory with the Same Counterparty. The effect is to record purchases and sales of inventory that are entered into in contemplation of each other with the same counterparty 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. These purchases and sales are used to optimize transportation or fulfil marketing arrangements. As a result of the adoption of this policy, reported revenues and purchased product costs for 2006 included offsets of $3,238 million.

Purchased product and revenues before the netting increased in 2006 due to third party purchases and sales as a result of our sale of the Empress NGL plant to a third party at the end of 2005. For 2006, this incremental activity to facilitate the movement of our gas through the Empress plant totaled approximately $1.9 billion.

2005 vs 2004

Revenues and purchased product expenses increased in 2005 as a result of increases in commodity prices while third party optimization volumes remained relatively flat year over year.

Corporate

Financial Results

Year Ended December 31 ($ millions)	2006	2005	2004
Revenues	**$ 2,050**	$ (466)	$ (197)
Expenses			
Operating	**(12)**	2	(1)
Depreciation, depletion and amortization	**75**	73	61
Segment Income (Loss)	**$ 1,987**	$ (541)	$ (257)
Administrative	**271**	268	197
Interest, net	**396**	524	398
Accretion of asset retirement obligation	**50**	37	22
Foreign exchange (gain) loss, net	**14**	(24)	(412)
Stock-based compensation – options	**—**	15	17
(Gain) on divestitures	**(323)**	—	(59)

The 2006 corporate revenues of $2,050 million are unrealized mark-to-market gains related to financial natural gas and crude oil commodity hedge contracts compared with $466 million unrealized mark-to-market losses in 2005 (2004 – $198 million loss). The operating expense recovery of $12 million for 2006 is due to unrealized mark-to-market gains related to long-term financial power commodity hedge contracts entered into in the fourth quarter of 2006.

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

Financial Results

Year Ended December 31 ($ millions)	2006	2005	2004
Continuing Operations			
Natural Gas	**$ 1,910**	$ (494)	$ (21)
Crude Oil	**140**	28	(177)
	2,050	(466)	(198)
Expenses	**(10)**	3	(7)
	2,060	(469)	(191)
Income Tax Expense	**703**	158	74
Unrealized Mark-to-Market Gains (Losses), after tax	**$ 1,357**	$ (311)	$ (117)

Price volatility has impacted net earnings as a result of EnCana's price risk management activities. As a means of managing this commodity price volatility, EnCana enters into various financial instrument agreements and physical contracts. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. On December 31, 2006, the forward price curve for 2007 for WTI was basically unchanged from December 31, 2005 at $65.02 per bbl, while NYMEX gas decreased by 32 percent to $6.97 per Mcf.

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

2006 vs 2005

Administrative expenses in 2006 were comparable with 2005 due to increases for office expenses, the higher U.S./Canadian dollar and increased general costs offset by lower long-term compensation expenses, which are tied to EnCana's Common Share price. Administrative expenses in 2006 were $0.17 per Mcfe compared with $0.18 per Mcfe in 2005.

Interest expense in 2006 decreased by $128 million mainly as a result of a $121 million one time charge incurred in 2005 to retire certain medium term notes, and lower average outstanding debt in 2006 due to repayments using the sales proceeds from the Entrega Pipeline, Ecuador, Brazil and gas storage divestitures.

The gain on divestitures in 2006 relates to the divestitures of the Chinook heavy oil discovery offshore Brazil in the third quarter and the Entrega Pipeline in the first quarter.

2005 vs 2004

Administrative expenses increased $71 million compared to 2004. The increase results from higher long-term compensation expenses that are tied to EnCana's Common Share price and the change in the U.S./Canadian dollar exchange rate. Administrative costs in 2005 were $0.18 per Mcfe compared with $0.14 per Mcfe in 2004.

Interest expense in 2005 increased as a result of a $121 million ($79 million after-tax) charge to retire certain medium term notes. EnCana's total long-term debt decreased by $1,154 million to $6,776 million at December 31, 2005 compared with $7,930 million at December 31, 2004.

The foreign exchange gain of $24 million in 2005 includes $113 million ($92 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, EnCana 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. Other foreign exchange gains and losses result from the settlement of foreign currency transactions and the translation of EnCana's monetary assets and liabilities.

Income Tax

2006 vs 2005

The effective tax rate for 2006 is 27.3 percent compared to 30.8 percent for 2005. The decrease is largely due to a decrease in future income tax expense of $457 million as a result of reductions in the Canadian federal and Alberta corporate tax rates, which were enacted in the second quarter of 2006. The Canadian federal tax rate of 22.1 percent is to be reduced to 19 percent over the 2008 – 2010 period. The Alberta tax rate was reduced from 11.5 percent to 10 percent effective April 1, 2006.

Cash taxes included in cash flow for 2006 were $893 million compared to $626 million in 2005. The increase in cash tax expense over 2005 primarily reflects higher Canadian income resulting from higher prices in 2005, which is recognized for income tax purposes in 2006. An additional $49 million of cash tax was incurred in 2006, resulting from the divestiture of the Brazil operations, compared to $578 million of cash tax in the second quarter of 2005 as a result of the divestiture of the Gulf of Mexico operations. These amounts are included in investing activities in the Consolidated Statement of Cash Flows.

2005 vs 2004

The effective tax rate for 2005 was 30.8 percent compared with 23.2 percent in 2004. The 2005 income tax provision has been reduced by the net benefit of tax basis retained on divestitures of $68 million compared to $169 million in 2004. The 2004 effective tax rate included a reduction of $109 million in future income taxes, resulting from the reduction in the Alberta tax rate from 12.5 percent to 11.5 percent.

Current tax expense was $1,204 million in 2005 compared to $559 million in 2004; $578 million of this increase relates to the sale of Gulf of Mexico assets and has been shown as cash outflow from investing activities in the Consolidated Statement of Cash Flows. The balance of $626 million has been included in cash flow.

Further information regarding EnCana's effective tax rate can be found in Note 8 to the Consolidated Financial Statements. 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, which are subject to tax, either current or future. There are a variety of items of this type, including:

- The effects of asset divestitures 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 or losses; and
- Items such as resource allowance and non-deductible Crown payments, where the income tax treatment is different from the accounting treatment.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. 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

Year Ended December 31 ($ millions)	**2006**	2005	2004
Upstream	**$ 6,151**	$ 6,202	$ 4,343
Market Optimization	**44**	197	10
Corporate	**74**	78	46
Total Core Capital Expenditures	**$ 6,269**	$ 6,477	$ 4,399
Acquisitions	**331**	448	2,699
Divestitures	**(689)**	(2,523)	(1,456)
Discontinued Operations	**(2,647)**	(305)	(1,436)
Net Capital Investment	**$ 3,264**	$ 4,097	$ 4,206

EnCana's capital investment for the year ended December 31, 2006 was funded by cash flow.

Upstream Capital Expenditures

2006 vs 2005

Capital spending during 2006 was primarily focused on continued development of our North American key resource plays. Natural gas capital expenditures were focused on continued development of the Company's key resource plays in Cutbank Ridge and Bighorn in Canada and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2006 was concentrated on expansion of the Company's SAGD projects located at Foster Creek and Christina Lake and developing the new resource play at Borealis.

The $51 million decrease in Upstream core capital expenditures in 2006 was primarily due to:

- Canadian core capital expenditures decreased by $392 million offset by an increase in foreign exchange of $257 million for a net reported decrease of $135 million. The overall decrease is due to:
  - Crown land sales and other land costs were $260 million or 68 percent lower than the prior year mainly due to large land purchases in 2005;
  - Total drilling and completion costs decreased $307 million or 13 percent due to a decrease in the total number of wells drilled compared to 2005;
  - Facility costs increased $199 million or 16 percent mainly due to the costs resulting from the continued expansion of Foster Creek and Christina Lake facilities and the construction of the Steeprock and Kakwa gas plants at Cutbank Ridge and Bighorn respectively;
  - In Canada, the Company drilled 3,009 net wells in 2006 compared to 4,038 net wells in 2005. The decrease resulted from the Company's decision to decrease drilling activity in response to higher industry costs and new regulations related to CBM water well testing, which delayed drilling. In various locations, the Company redirected capital spending to recompletion and tie-in of existing wells instead of drilling new wells in the current price environment.
- U.S. core capital expenditures increased $79 million to $2,061 million primarily due to additional drilling and completion costs at Fort Worth related to the development of the Barnett Shale play, increased activity at Jonah after receipt of the Bureau of Land Management Record of Decision approving further development of the field and the drilling of several deep gas wells in the Deep Bossier play in East Texas. The number of net wells drilled increased slightly to 639 from 617 in 2005.

2005 vs 2004

Capital spending during 2005 was primarily focused on North American resource play land capture, drilling programs and facility expansion. Natural gas capital expenditures were focused on continued development of the Company's key resource plays in Greater Sierra, Cutbank Ridge, CBM Integrated and Shallow Gas in Canada, and Piceance, Jonah, East Texas and Fort Worth in the United States. Crude oil capital spending in 2005 was concentrated on expansion of the Company's SAGD projects located at Foster Creek and Christina Lake, the waterflood program at Pelican Lake in Alberta and Weyburn in Saskatchewan. In addition, capital was directed at identifying and developing new resource plays at Bighorn and Borealis.

The $1.9 billion increase in Upstream core capital expenditures in 2005 was primarily due to:

- Canadian core capital expenditures increased approximately $1.1 billion to $4.2 billion. This includes approximately $219 million related to the change in the U.S./Canadian dollar exchange rate as well as the following factors:
  - Crown land sales and other land costs in 2005 were $274 million higher than the prior year mainly due to significantly higher land prices;
  - Drilling and completion costs increased $608 million in 2005 due to service cost increases as a result of industry activity levels;

- Facility costs increased $113 million in 2005 mainly due to the Foster Creek expansion, which was completed in the fourth quarter of 2005; and
- In Canada, the Company drilled 4,038 net wells in 2005 compared to 4,385 net wells in 2004. This decrease of 8 percent relates mainly to decreased drilling of shallow gas wells in southern and west-central Alberta due to weather related delays during the summer and service sector shortages as a result of record levels of activity in the industry.

- U.S. core capital expenditures increased $0.7 billion in 2005 to $2 billion primarily due to increases in drilling and completion costs. In the U.S. the Company drilled 617 net wells in 2005 compared to 534 net wells in 2004, an increase of 16 percent. Drilling was focused on continued development of the four key resource plays of Jonah, Piceance, Fort Worth and East Texas.

Canadian East Coast EnCana continues to advance its plans for the Deep Panuke project. In June 2006, EnCana and the Province of Nova Scotia reached an Offshore Strategic Energy Agreement that established the framework for the potential development of Deep Panuke. In November 2006, EnCana filed the Development Plan Application with the Canada-Nova Scotia Offshore Petroleum Board, which included an Environmental Assessment Report and an application to the National Energy Board for approval of the construction and operation of an offshore pipeline. The hearings for the project before the Canada-Nova Scotia Offshore Petroleum Board and the National Energy Board are scheduled to commence on March 5, 2007 in Halifax, Nova Scotia. The hearings are expected to last a few weeks.

Brazil EnCana has non-operated interests in 10 deep and ultra-deep water exploration blocks offshore Brazil, nine of which are operated by Petrobras, the Brazilian national oil company. EnCana and its partners drilled one gross exploration well in 2006 in the Campos Basin.

Chad In 2006, EnCana's capital program in Chad included drilling five gross exploratory wells and conducting several seismic surveys. In the third quarter of 2006, EnCana made the decision to divest of these assets. On January 12, 2007, EnCana announced that it had sold its interests in all its exploration assets in Chad for approximately $203 million, subject to post-closing adjustments, which will result in a gain on sale.

France In February 2006, a subsidiary of EnCana was granted a 100 percent interest in the Foix exploration permit in the onshore Aquitaine Basin in southwest France. EnCana has plans for a two well exploration drilling program in 2007 to identify the potential for the development of a natural gas resource play.

Market Optimization Capital Expenditures

Expenditures in 2006 and 2005 were mostly focused on the completion of construction for the Entrega Pipeline prior to the sale in February 2006.

Corporate Capital Expenditures

Corporate capital expenditures have generally been directed to business information systems and leasehold improvements. In addition, 2006 ($37 million) and 2005 ($36 million) include land purchases and costs related to the development of a Calgary office complex. 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.

Acquisitions, Divestitures and Discontinued Operations

Acquisitions included minor property acquisitions in 2006 and 2005, while divestitures included the sale of the Entrega Pipeline in Colorado and the Brazil oil discovery in 2006, and the sale of the Gulf of Mexico assets and other minor property divestitures in 2005.

Included in Discontinued Operations are the divestitures of EnCana's Ecuador and gas storage operations (discussed in the Discontinued Operations section of this MD&A) in 2006, with the proceeds reduced by capital spending prior to the sales.

Proved Oil and Gas Reserves

Proved Reserves by Country
Constant Prices After Royalties

As at December 31	Natural Gas (billions of cubic feet) 2006	2006 vs 2005	2005	2005 vs. 2004	2004	Crude Oil and NGLs (1) (millions of barrels) 2006	2006 vs 2005	2005	2005 vs. 2004(2)	2004
Canada	**7,028**	**8%**	6,517	12%	5,824	**1,079.4**	**16%**	932.5	48%	629.6
United States	**5,390**	**2%**	5,267	14%	4,636	**54.0**	**2%**	53.1	-42%	91.0
Ecuador	**—**	**—**	—	—	—	**—**	**-100%**	135.0	-6%	143.3
Total	**12,418**	**5%**	11,784	13%	10,460	**1,133.4**	**1%**	1,120.6	30%	863.9

(1) Crude Oil and NGLs include condensate.
(2) Prices at year-end 2005 allowed the reinstatement of 362.7 million barrels that were deducted as a revision due to the bitumen price at year-end 2004.

Each year, EnCana engages independent qualified reserve evaluators to prepare reports on 100 percent of the Corporation's oil and natural gas reserves. The Company has a Reserves Committee of independent Board members, which reviews the qualifications and appointment of the independent qualified reserve evaluators. The Committee also reviews the procedure for providing information to the evaluators. EnCana's disclosure of reserves data is covered by NI 51-101 as amended by a Mutual Reliance Review System Decision Document dated December 16, 2003 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and Financial Accounting Standards Board ("FASB") reserve reporting requirements. These standards require that reserves be estimated employing the single day field price of the commodity at the effective date of the valuation – in this case, December 31, 2006.

Proved Reserves Reconciliation by Country
Constant Prices After Royalties

As at December 31, 2006	Natural Gas (billions of cubic feet) Canada	USA	Total	Crude Oil and NGLs (1) (millions of barrels) Canada	USA	Ecuador (3)	Total
Beginning of year	6,517	5,267	11,784	932.5	53.1	135.0	1,120.6
Revisions and improved recovery	301	(88)	213	(39.0)	(1.1)	—	(40.1)
Extensions and discoveries	1,014	606	1,620	238.7	6.4	—	245.1
Acquisitions	—	68	68	—	0.3	—	0.3
Divestitures	(6)	(32)	(38)	(0.1)	—	(130.6)	(130.7)
Production	(798)	(431)	(1,229)	(52.7)	(4.7)	(4.4)	(61.8)
End of year	**7,028**	**5,390**	**12,418**	**1,079.4** (2)	**54.0**	**—**	**1,133.4**

(1) Crude Oil and NGLs include condensate.
(2) Effective January 2, 2007, the Corporation's Foster Creek and Christina Lake operations were contributed to a 50/50 upstream partnership with ConocoPhillips. The Corporation's ownership in reserves associated with these properties were reduced by 398 million barrels.
(3) Ecuador operations sold February 28, 2006.

Natural Gas

EnCana's proved natural gas reserves as at December 31, 2006, totaled 12,418 Bcf. Approximately 152 percent of production was replaced by reserves additions during 2006. Extensions and discoveries resulting from successful exploration and development capital programs amounted to 1,620 Bcf. Positive revisions of 213 Bcf were less than 2 percent of natural gas reserves at the beginning of 2006. In Canada, positive revisions of 301 Bcf (or 5 percent of the opening balance) were largely associated with CBM Integrated. Downward revisions in the United States amounted to 88 Bcf (or less than 2 percent of natural gas reserves at the beginning of 2006), mainly due to proved undeveloped reserves being removed consistent with planned moderation in drilling activity. Acquisitions and divestitures account for less than 1 percent of the opening natural gas reserves balance.

Crude Oil and NGLs

EnCana's proved crude oil and NGLs reserves as at December 31, 2006 totaled 1,133 MMbbls. Reserve additions from continuing operations replaced over 357 percent of production. Extensions and discoveries amounted to 245 MMbbls, while revisions were negative 40 MMbbls (or 4 percent of the opening balance). Christina Lake and Foster Creek accounted for 226 MMbbls or more than 90 percent of the extensions and discoveries. A negative revision in net oil reserves at Foster Creek of approximately 67 MMBbls was due to a higher average royalty rate as a direct result of an almost two-fold increase in the December 31, 2006 field price in comparison to the previous year. This was partially offset by positive revisions elsewhere in Canada. Reserve changes due to acquisitions and divestitures in continuing operations during 2006 were not significant. With the creation of the integrated oilsands business, effective January 2, 2007, ConocoPhillips and EnCana each own a 50 percent interest in the Foster Creek and Christina Lake upstream operations and the Wood River and Borger refineries. As a result of this transaction, the Corporation's estimated proved oil reserves were reduced by 398 MMbbls in exchange for a 50 percent interest in the two refineries.

Discontinued Operations

Discontinued operations in the Consolidated Financial Statements include:

- Ecuador
- United Kingdom
- Midstream

EnCana's 2006 net earnings from discontinued operations were $601 million compared to $597 million in 2005 and include realized financial hedge gains of $7 million after-tax and unrealized financial hedge gains of $13 million after-tax.

Ecuador

On February 28, 2006, EnCana completed the sale of its interests in Ecuador operations for $1.4 billion before indemnifications and recorded a loss on sale of $47 million. During the second quarter, the Government of Ecuador seized the Block 15 assets, in relation to which EnCana previously held a 40 percent economic interest, from the operator. This was an event requiring indemnification under the terms of EnCana's sale agreement with the purchaser. During the third quarter, EnCana paid the previously accrued indemnity claim of approximately $265 million calculated in accordance with the terms of the agreement. 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.

Ecuador

Year Ended December 31	2006	2005	2004
Sales Volumes			
Crude Oil (bbls/d)	**12,366**	71,065	77,993
($ millions)			
Net Earnings (Loss) from Discontinued Operations (1)	**$ (279)**	$ 131	$ (33)
Capital Investment (2)	**(1,116)**	179	240

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for Ecuador has not been recorded in the Consolidated Statement of Earnings for discontinued operations. Amounts recorded as DD&A expense in 2006 and 2005 represent provisions that were recorded against the net book value of the Ecuador operations to recognize Management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

(2) Capital Investment in 2006 includes the net proceeds of divestiture of $1.4 billion, reduced by the indemnity claim, which was paid in the third quarter.

2006 vs 2005

Ecuador's Net Loss from discontinued operations in 2006 is a result of the sale and the 2005 Net Earnings are the result of operations.

2005 vs 2004

Production volumes in 2005 averaged 72,916 bbls/d, down 5 percent from 2004. Sales volumes in 2005 decreased 9 percent to average 71,065 bbls/d due to declining production in Tarapoa and Block 15 as well as the shift to an underlift position at December 31, 2005 from an overlift position at the end of 2004.

Production and mineral taxes were $70 million higher in 2005 compared to 2004 as a result of higher realized prices on the Tarapoa block sales volumes partially offset by lower Tarapoa sales volumes. EnCana is required to pay a percentage of revenue from this block to the Ecuador government based on realized prices over a base price.

United Kingdom

Year Ended December 31	2006	2005	2004
Sales Volumes			
Produced Gas (MMcf/d)	**–**	—	30
Crude Oil (bbls/d)	**–**	—	14,128
NGLs (bbls/d)	**–**	—	1,845
Total (BOE/d)	**–**	—	20,973
($ millions)			
Net Earnings from Discontinued Operations (1)	**$ 5**	$ 35	$ 1,338
Capital Investment	**–**	—	488

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for U.K. has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

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.

Midstream

On March 6, 2006, EnCana announced it had reached an agreement to sell its gas storage business interests for approximately $1.5 billion. The sale, to a single purchaser, closed in two stages. The first stage of the sale closed on May 12, 2006 for proceeds of approximately $1.3 billion. On November 17, 2006, EnCana closed the second and final phase with its sale of the Wild Goose storage facility interests in California for proceeds of approximately $0.2 billion after the receipt of the California Public Utilities Commission approval.

Midstream

Year Ended December 31 ($ millions)	2006	2005	2004
Net Earnings from Discontinued Operations [1]	**$ 875**	$ 431	$ 118
Capital Investment	**(1,531)**	(484)	(20)

(1) In accordance with Canadian generally accepted accounting principles, DD&A expense for the natural gas storage business has not been recorded in the Consolidated Statement of Earnings for discontinued operations.

2006 vs 2005

Midstream's net earnings from discontinued operations in 2006 mainly result from the gain on sale of the gas storage operations in May and November 2006, which totaled $829 million after-tax. The 2005 amount also includes the NGLs processing business, which was sold in December 2005 for an after-tax gain on sale of $370 million.

2005 vs 2004

On December 13, 2005, EnCana sold substantially all of its NGLs processing business for proceeds of approximately $625 million subject to post-closing adjustments.

Net earnings in 2005 for the discontinued Midstream businesses were $431 million, an increase of $313 million over 2004. Included in 2005 net earnings is a $370 million after-tax gain on the sale of the NGLs processing business. 2005 net earnings have been reduced by $30 million as a result of agreements by WD Energy Services Inc., one of EnCana's indirect subsidiaries, to settle certain California and New York lawsuits, as further described in this MD&A under the heading Contractual Obligations and Contingencies.

Liquidity and Capital Resources

Year Ended December 31 ($ millions)	2006	2005	2004
Net cash provided by (used in)			
Operating activities	**$ 7,973**	$ 7,430	$ 4,591
Investing activities	**(3,382)**	(4,520)	(4,259)
Financing activities	**(4,294)**	(3,396)	163
Deduct: Foreign exchange gain on cash and cash equivalents held in foreign currency	**–**	2	6
Increase (decrease) in cash and cash equivalents	**$ 297**	$ (488)	$ 489

Operating Activities

Cash flow from continuing operations was $7,043 million in 2006 compared to $6,962 million in 2005. The $81 million increase in cash flow from continuing operations in 2006 was primarily due to increased revenues driven by higher liquids prices, realized financial commodity hedge gains and natural gas sales volumes partially reduced by lower natural gas prices, increased operating expenses and higher cash taxes. The working capital surplus at December 31, 2006 was $11 million compared to a deficit of $1,267 million at December 31, 2005 mainly as a result of a net change in risk management of $2,121 million. Cash flow from continuing operations comprises most of EnCana's cash provided by operating activities.

Investing Activities

Net cash of $3,382 million was used for investing activities in 2006, a decrease of $1,138 million compared to 2005. Capital expenditures, including property acquisitions, decreased $325 million and cash tax on divestitures of assets decreased by $529 million for the year ended December 31, 2006.

Financing Activities

Total long-term debt as at December 31, 2006 increased by $58 million over 2005 primarily due to net revolving long-term debt issuances of $134 million offset by a fixed rate long-term debt repayment of $73 million. EnCana's net debt adjusted for working capital was $6,566 million as at December 31, 2006 compared with $7,970 million at December 31, 2005. During 2006, EnCana purchased 85.6 million of its Common Shares for total consideration of $4,219 million.

On June 9, 2006, an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., filed a debt shelf prospectus in the amount of $2 billion under the multijurisdictional disclosure system ("MJDS"). This shelf prospectus replaces EnCana Holdings Finance Corp.'s previous $2 billion shelf prospectus, which expired in April 2006. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation.

On September 22, 2006, EnCana filed a debt shelf prospectus in the amount of $2 billion under the MJDS. This shelf prospectus replaces EnCana's previous $2 billion shelf prospectus, which expired on October 16, 2006. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. At December 31, 2006, EnCana had available unused committed bank credit facilities in the amount of $2.8 billion and unused capacity under shelf prospectuses for up to $4.4 billion, the availability of which is dependent upon market conditions.

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 'Positive' outlook.

Financial Metrics

Year Ended December 31	2006	2005
Net Debt to Capitalization	**27%**	33%
Net Debt to Adjusted EBITDA (1)	**0.6x**	1.1x

(1) Adjusted EBITDA is a non-GAAP measure that is defined as net earnings from Continuing Operations before gain on divestitures, income taxes, foreign exchange gains or losses, interest net, accretion of asset retirement obligation, and depreciation, depletion and amortization.

Net Debt to Capitalization and Net Debt to Adjusted EBITDA are two ratios Management uses to steward the Company's overall debt position as measures of the Company's overall financial strength.

Outstanding Share Data

(millions)	2006	2005 (1)	2004 (1)
Common Shares outstanding, beginning of year	**854.9**	900.6	921.2
Issued under option plans	**8.6**	15.0	19.4
Shares purchased (Normal Course Issuer Bid)	**(85.6)**	(55.2)	(40.0)
Shares purchased (Performance Share Unit Plan)	**–**	(5.5)	–
Common Shares outstanding, end of year	**777.9**	854.9	900.6
Weighted average Common Shares outstanding – diluted	**836.5**	889.2	936.0

(1) The number of Common Shares outstanding prior to the 2 for 1 share split has been restated for comparison.

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. There were no Preferred Shares outstanding as at December 31, 2006.

Employees and directors have been granted options to purchase Common Shares under various plans. At December 31, 2006, 11.8 million options without Tandem Share Appreciation Rights ("TSAR") attached were outstanding, all of which are exercisable.

Long-term incentives may be granted to EnCana employees in the form of stock options and Performance Share Units ("PSUs"). Stock options granted after December 31, 2003 have an associated TSAR attached and employees may elect to exercise either the stock option or the associated Share Appreciation Right ("SAR"). Stock option exercises result in the issuance of new Common Shares while TSAR exercises result in cash payments by the Company. PSUs will not result in the issuance of new Common Shares by the Company as shares are purchased through a trust for payment, should performance considerations be met. At December 31, 2006, there were 5.5 million shares held in trust for issuance upon vesting of PSUs.

EnCana has obtained regulatory approval under Canadian securities laws to purchase Common Shares under five consecutive NCIBs. During 2006, EnCana purchased 85.6 million Common Shares for total consideration of $4,219 million ($49.26 per Common Share). As of December 31, 2006, the number of Common Shares that EnCana will be permitted to purchase in 2007 under the current NCIB is 55.7 million.

EnCana pays quarterly dividends to shareholders at the discretion of the Board of Directors. These dividends totaled $304 million in 2006, $238 million for 2005, and $183 million for 2004. These dividends were funded by cash flow. At December 31, 2006, the quarterly dividend paid to shareholders was $0.100 per Common Share (2005 – $0.075; 2004 – $0.050).

Normal Course Issuer Bid (millions)	Share Purchases **2006**	2005
Bid expired October 2005	**–**	55.2
Bid expired October 2006	**61.1**	—
Bid expiring November 2007	**24.5**	—
	85.6	55.2

Contractual Obligations and Contingencies

Contractual Obligations (1) ($ millions)	Expected Payment Date 2007	2008 to 2009	2010 to 2011	2012+	Total
Long-Term Debt (2)	$ 257	$ 857	$ 2,260	$ 3,400	**$ 6,774**
Asset Retirement Obligations	44	75	58	5,155	**5,332**
Pipeline Transportation	431	836	791	2,144	**4,202**
Purchase of Goods and Services	427	509	281	790	**2,007**
Operating Leases (3)	52	92	97	237	**478**
Product Purchases	54	47	24	98	**223**
Capital Commitments	75	35	—	38	**148**
Other Long-Term Commitments	13	10	3	—	**26**
Total	$ 1,353	$ 2,461	$ 3,514	$11,862	**$19,190**
Product Sales	$ 41	$ 84	$ 85	$ 252	**$ 462**
Other Commitments	$ (36)	$ —	$ —	$ —	**$ (36)**

(1) In addition, the Company has made commitments related to its risk management program. See Note 18 to the Consolidated Financial Statements. The Company has an obligation to fund its Pension Plan and other Post-Employment Benefits as disclosed in Note 15 to the Consolidated Financial Statements.

(2) Excludes interest component. See Note 12 to the Consolidated Financial Statements.

(3) Related to office space.

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

Included in EnCana's total long-term debt commitments of $6,774 million at December 31, 2006 are $1,560 million in commitments related to Bankers' Acceptances and Commercial Paper. These amounts are fully supported and Management expects they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year. Further details regarding EnCana's long-term debt are described in Note 12 to the Consolidated Financial Statements.

As at December 31, 2006, EnCana remained a party to long-term, fixed price, physical contracts with a current delivery of approximately 38 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 125 Bcf at a weighted average price of $3.72 per Mcf. At December 31, 2006, these transactions had an unrealized loss of $267 million.

Leases

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

Legal Proceedings

EnCana is involved in various legal claims associated with the normal course of operations and 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 antitrust 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 payments 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 States 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 that 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

CHANGES IN ACCOUNTING PRINCIPLES

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". As of January 1, 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 year ended December 31, 2006 include offsets of $3,238 million.

RECENT ACCOUNTING PRONOUNCEMENTS

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2007, the Company is required to adopt the Canadian Institute of Chartered Accountants ("CICA") Section 1530 "Comprehensive Income", Section 3251 "Equity", Section 3855 "Financial Instruments – Recognition and Measurement", and Section 3865 "Hedges", which were issued in January 2005. Under the new standards, a new financial statement, the Consolidated Statement of Comprehensive Income, has been introduced that will provide for certain gains and losses, including foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives, are to be included in the Company's Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified. The Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges.
- As of January 1, 2007, EnCana is required to adopt revised CICA Section 1506, "Accounting Changes", which provides expanded disclosures for changes in accounting polices, accounting estimates and corrections of errors, which were issued in July 2006. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information. EnCana does not expect application of this revised standard to have a material impact on its Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation", which will replace Section 3861 "Financial Instruments – Disclosure and Presentation". The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt CICA Section 1535 "Capital Disclosures", which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.
- In January 2006, the Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. A summary of EnCana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the CICA guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for and development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property divestiture, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of EnCana's oil and gas reserves are evaluated and reported on by independent qualified reserve evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and

ii) the costs of unproved properties that have been subject to a separate impairment test.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made. Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets, such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual payments to settle the obligations may differ from estimated amounts.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed by EnCana for impairment at least annually. Goodwill was allocated to the business segments based on their respective book values compared to fair values. If it is determined that the fair value of the assets and liabilities of the business segment is less than the book value of the business segment at the time of assessment, an impairment amount is determined by deducting the fair value from the book value and applying it against the book balance of goodwill. The offset is charged to the Consolidated Statement of Earnings as additional DD&A.

Derivative Financial Instruments

Derivative financial instruments are used by EnCana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is to not use derivative financial instruments for speculative purposes.

The Company enters into financial transactions to help reduce its exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics. These transactions generally are swaps, collars, or options and are generally entered into with major financial institutions or commodities trading institutions.

EnCana may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of its total debt portfolio and related overall cost of borrowing. The interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

EnCana may enter into hedges of its foreign currency exposures on foreign currency denominated long-term debt by entering into offsetting forward exchange contracts. Foreign exchange translation gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange in the period to which they relate offsetting the respective translation losses and gains recognized on the underlying foreign currency long-term debt. Premiums or discounts on these forward instruments are amortized as an adjustment of interest expense over the term of the contract.

EnCana also may purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from the Company's natural gas and crude oil financial derivatives are recognized in natural gas and crude oil revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indicators. In 2004, 2005, and 2006, the Company elected not to designate any of its current price risk management activities as accounting hedges and, accordingly, accounts for all derivatives using the mark-to-market accounting method.

Pensions and Other Post-Employment Benefits

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan. Pension costs are a component of compensation costs.

Performance Share Units ("PSUs")

The PSU plans provide for a range of payouts, based on EnCana's performance relative to certain peers. EnCana expenses the cost of PSUs based on expected payouts; however, the amounts to be paid, if any, may vary from the current estimate.

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; and
- reputational risks.

FINANCIAL RISKS

Sensitivity of 2007 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Including Hedges) (1) ($ millions)	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 320	$ 330
$8.00 per barrel increase in the WTI oil price	100	90
$1.00 per barrel increase in the 3-2-1 U.S. Gulf Coast Crack Spread	30	30
$0.01 decrease in the U.S./Canadian dollar exchange rate	(5)	10

(1) Hedge position as at December 31, 2006. Based on forward curve commodity price and forward curve estimates dated December 31, 2006.

Sensitivity of 2007 Net Earnings from Continuing Operations and Cash Flow from Continuing Operations (Excluding Hedges) (1) ($ millions)	Net Earnings from Continuing Operations	Cash Flow from Continuing Operations
$1.00 per million British thermal units increase in the NYMEX gas price	$ 660	$ 700
$8.00 per barrel increase in the WTI oil price	180	170
$1.00 per barrel increase in the 3-2-1 U.S. Gulf Coast Crack Spread	30	30
$0.01 decrease in the U.S./Canadian dollar exchange rate	(5)	10

(1) Based on forward curve commodity price and forward curve estimates dated December 31, 2006.

EnCana 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 and is subject to limits established by the Board of Directors. As a means of mitigating exposure to commodity price risk volatility, the Company has entered into various financial instrument agreements. The details of these instruments, including any unrealized gains or losses, as of December 31, 2006, are disclosed in Note 16 to the Consolidated Financial Statements.

EnCana 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 to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

With respect to transactions involving proprietary production or assets, the financial instruments generally used by EnCana are swaps 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 enters into swaps, which fix the AECO and NYMEX prices, and put and collar options, which fix the range of AECO and NYMEX prices. To help protect against widening natural gas price differentials in various production areas, EnCana 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 $35 million at December 31, 2006.

EnCana 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 $47 million at December 31, 2006.

For crude oil price risk, the Company has partially mitigated its exposure to the WTI NYMEX price for approximately 92 percent of its expected 2007 oil production with fixed price swaps and put options.

To manage its electricity consumption costs, EnCana has entered into two derivative contracts for a term of 11 years.

FOREIGN EXCHANGE

As a means of mitigating the exposure to fluctuations in the U.S. to Canadian exchange rate, EnCana 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.

EnCana 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. EnCana has entered into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

CREDIT RISK

EnCana 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 according to counterparties credit quality and transactions that are fully collateralized. A substantial portion of EnCana'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 include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that 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 EnCana's capital program with the results and identified learnings shared across the Company.

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.

EnCana 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, EnCana 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, accounting or internal control matters.

CLIMATE CHANGE

The Canadian federal government has announced its intention to regulate greenhouse gases and other air pollutants. It is currently developing a framework that outlines its clean air and climate change action plan, including a target to reduce greenhouse gas ("GHG") emissions by 45 percent – 65 percent by 2050 and a commitment to regulate industry on an emissions intensity basis in the short term. Currently, there are few technical details regarding the implementation of the government's plan to regulate industrial GHG emissions, but they have made a commitment to work with industry to develop the specifics.

As this federal program is under development, EnCana is unable to predict the total impact of the potential regulations upon its business; therefore, it is possible that the Corporation could face increases in operating costs in order to comply with GHG emissions legislation. However, EnCana, in cooperation with the Canadian Association of Petroleum Producers, will continue to work with the government to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

EnCana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded on five key elements:

- our significant weighting in natural gas and our high quality in-situ oilsands assets;
- our recognition as an industry leader in CO_2 sequestration;
- our focus on the development of technology to reduce GHG emissions;
- our involvement in the creation of industry best practices; and
- our industry leading oilsands steam-oil ratio, which translates directly into lower emissions intensity.

EnCana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on EnCana's GHG emissions is available in the Corporate Responsibility Report that is available on our website at **www.encana.com**.

REPUTATIONAL RISKS

EnCana takes a proactive 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.

Quarterly Results

Quarterly Summary	2006				2005			
($ millions, except per share (1) amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash Flow (2)	**$ 1,761**	**$ 1,894**	**$ 1,815**	**$ 1,691**	$ 2,510	$ 1,931	$ 1,572	$ 1,413
per share – diluted	**2.18**	**2.30**	**2.15**	**1.96**	2.88	2.20	1.76	1.55
Net Earnings	**663**	**1,358**	**2,157**	**1,474**	2,366	266	839	(45)
per share – basic	**0.84**	**1.68**	**2.60**	**1.74**	2.77	0.31	0.96	(0.05)
per share – diluted	**0.82**	**1.65**	**2.55**	**1.70**	2.71	0.30	0.94	(0.05)
Operating Earnings (3)	**675**	**1,078**	**824**	**694**	1,271	704	655	611
per share – diluted	**0.84**	**1.31**	**0.98**	**0.80**	1.46	0.80	0.73	0.67
Continuing Operations								
Cash Flow from Continuing Operations (2)	**1,742**	**1,883**	**1,839**	**1,579**	2,390	1,823	1,502	1,247
Net Earnings from Continuing Operations	**643**	**1,343**	**1,593**	**1,472**	1,869	348	774	(162)
per share – basic	**0.81**	**1.66**	**1.92**	**1.74**	2.19	0.41	0.89	(0.18)
per share – diluted	**0.80**	**1.63**	**1.88**	**1.70**	2.14	0.40	0.87	(0.18)
Operating Earnings from Continuing Operations (3)	**672**	**1,064**	**841**	**660**	1,229	733	611	475
Revenues, Net of Royalties	**3,676**	**4,029**	**3,922**	**4,772**	5,933	3,061	3,461	2,118

(1) Per share amounts have been restated for the effect of the common share split in 2005.
(2) Cash Flow and Cash Flow from Continuing Operations are non-GAAP measures and are defined under "Cash Flow".
(3) Operating Earnings and Operating Earnings from Continuing Operations are non-GAAP measures and are defined under "Operating Earnings".

Average North American natural gas prices in the fourth quarter of 2006 were 44 percent lower than the same period in 2005. A warm November and December in the Northeast U.S. combined with no significant supply losses from hurricane damage compared to 2005 caused NYMEX gas prices to drop in the fourth quarter.

The WTI crude oil price remained unchanged in the fourth quarter of 2006 compared to the same period in 2005. Concerns over Iran's nuclear program, Nigerian production shut-in due to militant attacks, ongoing instability in Iraq and U.S. gasoline supply partially offset by an uneventful hurricane season, resulted in WTI remaining flat from 2005, when there was significant oil supply disruptions. Fourth quarter Canadian heavy oil differentials were narrower in dollar terms relative to the fourth quarter of 2005, primarily due to the strength in asphalt and residual fuel oil markets supporting prices for Canadian heavy crude oil.

EnCana's net earnings for the fourth quarter of 2006 were $663 million, down $1,703 million from 2005. Net earnings from discontinued operations decreased $477 million to $20 million.

EnCana's net earnings from continuing operations in the fourth quarter of 2006 decreased $1,226 million or 66 percent to $643 million compared with the same period in 2005.

The decrease in net earnings from continuing operations was due to:

- Average North American natural gas prices, excluding financial hedges, decreased 44 percent to $5.79 per Mcf compared to $10.29 per Mcf in 2005;
- Unrealized mark-to-market gains of $99 million after-tax in 2006 compared with $661 million after-tax in 2005; and
- A $128 million after-tax unrealized foreign exchange loss on Canadian issued U.S. dollar debt in 2006 compared to a $21 million after-tax unrealized foreign exchange loss in 2005; this reflects the decrease in the U.S./Canadian dollar in the fourth quarter of 2006 compared to an increase in the Canadian dollar in the same period in 2005.

The decrease in net earnings from continuing operations was offset by:

- Realized financial natural gas and crude oil commodity hedging gains of $160 million after-tax compared with losses of $229 million after-tax in 2005;
- Average North American liquids prices, excluding financial hedges, increased 4 percent to $38.69 per bbl in 2006 compared to $37.16 per bbl in 2005; and
- Natural gas sales volumes increased 2 percent from the comparable period in 2005 to 3,406 MMcf/d.

During the fourth quarter of 2006, EnCana:

- Announced on October 5, 2006, an agreement that EnCana and ConocoPhillips were to create an integrated, North American heavy oil business consisting of upstream and downstream assets. This transaction closed on January 3, 2007; and
- Received regulatory approval to renew its NCIB. EnCana purchased 24.5 million shares at an average price of $50.74 in the fourth quarter of 2006 for a total cost of $1.2 billion under this renewed Bid.

Quarterly Sales Volumes	**2006**				2005			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Produced Gas (MMcf/d)	**3,406**	**3,359**	**3,361**	**3,343**	3,326	3,222	3,212	3,146
Crude Oil (bbls/d)	**128,048**	**126,658**	**129,070**	**138,370**	134,178	124,402	132,294	130,826
NGLs (bbls/d)	**24,106**	**23,907**	**24,400**	**24,421**	25,111	26,055	24,814	26,358
Continuing Operations (MMcfe/d) (1)	**4,319**	**4,262**	**4,282**	**4,320**	4,282	4,125	4,155	4,089
Discontinued Operations								
Ecuador (bbls/d)	**–**	**–**	**–**	**50,150**	69,943	68,710	73,176	72,487
Discontinued Operations (MMcfe/d) (1)	**–**	**–**	**–**	**301**	419	412	439	435
Total (MMcfe/d) (1)	**4,319**	**4,262**	**4,282**	**4,621**	4,701	4,537	4,594	4,524

(1) Liquids converted to thousand cubic feet equivalent at 1 barrel = 6 thousand cubic feet.

Outlook

EnCana plans to continue to focus principally on growing natural gas and crude oil production from unconventional resource plays in North America and to developing its high quality in-situ oilsands resources and expanding the Company's downstream heavy oil processing capacity.

Volatility in crude oil prices is expected to continue throughout 2007 as a result of market uncertainties over supply and refining disruptions, continued demand growth in China, OPEC actions, demand destruction from high energy prices and the overall state of the world economies. In the near term, the new pipeline capacity to the U.S. Gulf Coast should reduce the volatility on Canadian crude oil relative to world oil prices.

Natural gas prices are primarily driven by North American supply and demand, with weather being the key factor in the short term. EnCana believes that North American conventional gas supply has peaked in the past two years and that unconventional resource plays can at least partially offset conventional gas production declines. The industry's ability to respond to the constrained gas supply situation in North America remains challenged by land access and regulatory issues.

The Company expects its 2007 core capital investment program to be funded from cash flow.

Consistent with the Company's focus on shareholder value creation, EnCana's Board of Director's intends to double the quarterly dividend in 2007 to $0.20 per share. On February 14, 2007, the Company's Board of Directors declared a dividend for the first quarter of 2007 in the amount of $0.20 per share.

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 and inflationary pressures on service costs.

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 or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. 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 resources; projections relating to the volatility of crude oil prices in 2007 and beyond and the reasons therefor; projections of common share dividends for 2007; projections with respect to capital investments for 2007 and the source of funding therefor; the effect of the Company's risk management program, including the impact of derivative financial instruments and the percentage of oil production impacted by fixed price swaps and put options; the potential impact of revised accounting pronouncements on the Company; the Company's defence of lawsuits; the impact of climate change initiatives on operating costs; the adequacy of the Company's provision for taxes; the impact of new pipeline capacity to the U.S. Gulf Coast on future Canadian crude oil prices; projections that the Company's Bankers' Acceptances and Commercial Paper Program will continue to be fully supported by committed credit facilities and term loan facilities; and projections relating to North American conventional natural gas supplies and the ability of unconventional resource plays to partially offset future conventional gas production declines. 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 EnCana's current guidance; 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, bitumen, 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; 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 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; 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, 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 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 and Unbooked Resource Potential

EnCana uses the terms resource play, estimated ultimate recovery and unbooked resource potential. 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. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play potential 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.

CURRENCY AND NON-GAAP MEASURES AND REFERENCES TO ENCANA

All information included in this MD&A and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted. Sales forecasts reflect current public guidance on an after royalties basis. Current Corporate Guidance assumes a U.S. dollar exchange rate of $0.89 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 Adjusted 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.

DIFFERENCES IN ENCANA'S CORPORATE GOVERNANCE PRACTICES COMPARED TO NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the New York Stock Exchange ("NYSE"), EnCana is not required to comply with most of the NYSE Corporate Governance Standards and instead may comply with Canadian Corporate Governance Practices. EnCana is, however, required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. companies listed on the NYSE under NYSE corporate governance standards. A summary of these significant differences is available on EnCana's website (**www.encana.com**). Except as described in this summary, EnCana is in compliance with the NYSE corporate governance standards in all significant respects.

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**.

Management report

Management's Responsibility for Consolidated Financial Statements

The accompanying Consolidated Financial Statements of EnCana Corporation (the "Company") are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these financial statements.

The Company's Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee, which has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes-Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets at least on a quarterly basis.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to the Company's Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2006. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of the Company's internal control over financial reporting. Based on our evaluation, Management has concluded that the Company's internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and Management's assessment of the effectiveness of the Company's internal control over financial reporting as at December 31, 2006, as stated in their Auditor's Report. PricewaterhouseCoopers LLP has provided such opinions.

Randall K. Eresman
President &
Chief Executive Officer

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

February 22, 2007

Auditors' report

To the Shareholders of EnCana Corporation

We have completed an integrated audit of the Consolidated Financial Statements and internal control over financial reporting of EnCana Corporation (the "Company") as of December 31, 2006 and audits of its December 31, 2005 and December 31, 2004 Consolidated Financial Statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying Consolidated Balance Sheets of the Company as at December 31, 2006 and December 31, 2005, and the related Consolidated Statements of Earnings, Retained Earnings and Cash Flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits.

We conducted our audit of the Company's Consolidated Financial Statements as at December 31, 2006 and for the year then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audits of the Company's Consolidated Financial Statements as at December 31, 2005 and for each of the two years in the period ended December 31, 2005 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2006 and December 31, 2005 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited management's assessment, included in the accompanying Management Report, that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and divestitures of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or divestiture of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as at December 31, 2006 is fairly stated, in all material respects, based on criteria established in Internal Control — Integrated Framework issued by the COSO. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 22, 2007

Consolidated statement of earnings

For the years ended December 31 (US$ millions, except per share amounts)		2006	2005	2004
Revenues, Net of Royalties	(Note 3)			
Upstream		**$11,342**	$10,772	$ 7,488
Market Optimization		**3,007**	4,267	3,200
Corporate				
Unrealized gain (loss) on risk management	(Note 16)	**2,050**	(466)	(198)
Other		**–**	–	1
		16,399	14,573	10,491
Expenses	(Note 3)			
Production and mineral taxes		**349**	453	311
Transportation and selling		**1,070**	845	722
Operating		**1,655**	1,438	1,099
Purchased product		**2,862**	4,159	3,092
Depreciation, depletion and amortization		**3,112**	2,769	2,379
Administrative		**271**	268	197
Interest, net	(Note 6)	**396**	524	398
Accretion of asset retirement obligation	(Note 13)	**50**	37	22
Foreign exchange (gain) loss, net	(Note 7)	**14**	(24)	(412)
Stock-based compensation – options	(Note 14)	**–**	15	17
(Gain) on divestitures	(Note 5)	**(323)**	–	(59)
		9,456	10,484	7,766
Net Earnings Before Income Tax		**6,943**	4,089	2,725
Income tax expense	(Note 8)	**1,892**	1,260	632
Net Earnings From Continuing Operations		**5,051**	2,829	2,093
Net Earnings From Discontinued Operations	(Note 4)	**601**	597	1,420
Net Earnings		**$ 5,652**	$ 3,426	$ 3,513
Net Earnings From Continuing Operations per Common Share	(Note 17)			
Basic		**$ 6.16**	$ 3.26	$ 2.27
Diluted		**$ 6.04**	$ 3.18	$ 2.24
Net Earnings per Common Share	(Note 17)			
Basic		**$ 6.89**	$ 3.95	$ 3.82
Diluted		**$ 6.76**	$ 3.85	$ 3.75

Consolidated statement of retained earnings

For the years ended December 31 (US$ millions)		2006	2005	2004
Retained Earnings, Beginning of Year		**$ 9,481**	$ 7,935	$ 5,276
Net Earnings		**5,652**	3,426	3,513
Dividends on Common Shares		**(304)**	(238)	(183)
Charges for Normal Course Issuer Bid	(Note 14)	**(3,485)**	(1,642)	(671)
Retained Earnings, End of Year		**$11,344**	$ 9,481	$ 7,935

See accompanying Notes to Consolidated Financial Statements

Consolidated balance sheet

As at December 31 (US$ millions)		2006	2005
Assets			
Current Assets			
Cash and cash equivalents		$ 402	$ 105
Accounts receivable and accrued revenues		1,721	1,851
Risk management	(Note 16)	1,403	495
Inventories	(Note 9)	176	103
Assets of discontinued operations	(Note 4)	—	1,050
		3,702	3,604
Property, Plant and Equipment, net	(Notes 3, 10)	28,213	24,881
Investments and Other Assets	(Note 11)	533	496
Risk Management	(Note 16)	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 16)	14	1,227
Liabilities of discontinued operations	(Note 4)	—	438
Current portion of long-term debt	(Note 12)	257	73
		3,691	4,871
Long-Term Debt	(Note 12)	6,577	6,703
Other Liabilities		79	93
Risk Management	(Note 16)	2	102
Asset Retirement Obligation	(Note 13)	1,051	816
Liabilities of Discontinued Operations	(Note 4)	—	267
Future Income Taxes	(Note 8)	6,240	5,289
		17,640	18,141
Commitments and Contingencies	(Note 18)		
Shareholders' Equity			
Share capital	(Note 14)	4,587	5,131
Paid in surplus	(Note 14)	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

Approved by the Board

David P. O'Brien
Director

Barry W. Harrison
Director

Consolidated statement of cash flows

For the years ended December 31 (US$ millions)		2006	2005	2004
Operating Activities				
Net earnings from continuing operations		$ 5,051	$ 2,829	$ 2,093
Depreciation, depletion and amortization		3,112	2,769	2,379
Future income taxes	(Note 8)	950	56	73
Cash tax on sale of assets	(Note 8)	49	578	—
Unrealized (gain) loss on risk management	(Note 16)	(2,060)	469	191
Unrealized foreign exchange (gain) loss		76	(50)	(285)
Accretion of asset retirement obligation	(Note 13)	50	37	22
(Gain) on divestitures	(Note 5)	(323)	—	(59)
Other		138	274	88
Cash flow from discontinued operations		118	464	478
Net change in other assets and liabilities		138	(281)	(176)
Net change in non-cash working capital from continuing operations	(Note 17)	3,343	497	1,565
Net change in non-cash working capital from discontinued operations		(2,669)	(212)	(1,778)
Cash From Operating Activities		7,973	7,430	4,591
Investing Activities				
Business combinations		—	—	(2,335)
Capital expenditures	(Note 3)	(6,600)	(6,925)	(4,763)
Proceeds on disposal of assets	(Note 5)	689	2,523	1,456
Cash tax on sale of assets	(Note 8)	(49)	(578)	—
Equity investments		—	—	47
Net change in investments and other		2	(109)	44
Net change in non-cash working capital from continuing operations	(Note 17)	19	330	(29)
Discontinued operations		2,557	239	1,321
Cash (Used in) Investing Activities		(3,382)	(4,520)	(4,259)
Financing Activities				
Net issuance (repayment) of revolving long-term debt		134	(538)	72
Repayment of long-term debt		(73)	(1,104)	(2,759)
Issuance of long-term debt		—	429	3,761
Issuance of common shares	(Note 14)	179	294	281
Purchase of common shares	(Note 14)	(4,219)	(2,114)	(1,004)
Dividends on common shares		(304)	(238)	(183)
Other		(11)	(125)	(5)
Cash (Used in) From Financing Activities		(4,294)	(3,396)	163
Deduct: Foreign Exchange Loss on Cash and Cash Equivalents Held in Foreign Currency		—	2	6
Increase (Decrease) in Cash and Cash Equivalents		297	(488)	489
Cash and Cash Equivalents, Beginning of Year		105	593	104
Cash and Cash Equivalents, End of Year		$ 402	$ 105	$ 593
Supplemental Cash Flow Information	(Note 17)			

See accompanying Notes to Consolidated Financial Statements

Notes to consolidated financial statements

Prepared using Canadian Generally Accepted Accounting Principles
All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2006

1. Summary of Significant Accounting Policies

In these Consolidated Financial Statements, unless otherwise indicated, all dollar amounts are expressed in United States (U.S.) dollars. EnCana has adopted the U.S. dollar as its reporting currency since most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American upstream exploration and development companies. All references to US$ or to $ are to United States dollars and references to C$ are to Canadian dollars.

EnCana's continuing operations are in the business of exploration for, production and marketing of, natural gas, crude oil and natural gas liquids ("NGLs") and power generation operations.

A) Principles of Consolidation

The 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. Information prepared in accordance with generally accepted accounting principles in the United States is included in Note 20.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on EnCana's exploration and production business and are accounted for using the proportionate consolidation method, whereby EnCana's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

Investments in companies and partnerships in which EnCana does not have direct or joint control over the strategic operating, investing and financing decisions, but does have significant influence on them, are accounted for using the equity method.

B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included as a separate component of shareholders' equity.

Monetary assets and liabilities of the Company that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements in conformity with Canadian generally accepted accounting principles requires that Management make estimates and assumptions and use judgement regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which by their nature are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance-based compensation arrangements are subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

D) Revenue Recognition

Revenues associated with the sales of EnCana's natural gas, crude oil and NGLs are recognized when title passes from the Company to its customer. Natural gas and crude oil produced and sold by EnCana below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue. Realized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded in revenue when the product is sold.

Market optimization revenues and purchased product are recorded on a gross basis when EnCana takes title to product and has risks and rewards of ownership. Purchases and sales of inventory with the same counterparty that are entered into in contemplation of each other are recorded on a net basis. Revenues associated with the services provided where EnCana acts as agent are recorded as the services are provided. Revenues associated with the sale of natural gas storage services are recognized when the services are provided. Sales of electric power are recognized when power is provided to the customer.

Unrealized gains and losses from the Company's natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

Costs paid by EnCana to non-mineral interest owners based on production of natural gas, crude oil and NGLs are recognized when the product is produced.

F) Transportation and Selling Costs

Costs paid by EnCana for the transportation and selling of natural gas, crude oil and NGLs, including diluent, are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

EnCana accrues for its obligations under its employee benefit plans and the related costs, net of plan assets.

The cost of pensions and other retirement and post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The obligation is discounted using a market interest rate at the beginning of the year on high quality corporate debt instruments.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is done on a straight-line basis over a period covering the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

H) Income Taxes

EnCana follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs. Investment tax credits are recorded as an offset to the related expenditures.

I) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options without tandem share appreciation rights attached were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

K) Inventories

Product inventories are valued at the lower of average cost and net realizable value on a first-in, first-out basis. Materials and supplies are valued at cost.

L) Property, Plant and Equipment

Upstream

EnCana accounts for natural gas and crude oil properties in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for and the development of, natural gas and crude oil reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test.

Market Optimization

Midstream facilities, including natural gas storage facilities, natural gas liquids extraction plant facilities and power generation facilities, are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 20 to 25 years. Capital assets related to pipelines are carried at cost and depreciated or amortized using the straight-line method over their economic lives, which range from 20 to 35 years.

Corporate

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from 3 to 25 years. Land is carried at cost.

M) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

Interest is capitalized during the construction phase of large capital projects.

N) Amortization of Other Assets

Amortization of deferred items included in Investments and Other Assets is provided for where applicable, on a straight-line basis over the estimated useful lives of the assets.

O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to business levels, within the Company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

P) Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when identified and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. These obligations also include items for which the Company has made promissory estoppel. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Asset retirement costs for natural gas and crude oil assets are amortized using the unit-of-production method. Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) Stock-Based Compensation

EnCana records compensation expense in the Consolidated Financial Statements for stock options that do not have tandem share appreciation rights attached to them granted to employees and directors using the fair value method. Fair values are determined using the Black-Scholes-Merton option-pricing model. Compensation costs are recognized over the vesting period.

Obligations for payments, cash or common shares, under the Company's share appreciation rights, stock options with tandem share appreciation rights attached, deferred share units and performance share units plans are accrued as compensation expense over the vesting period. Fluctuations in the price of EnCana's common shares change the accrued compensation expense and are recognized when they occur.

R) Derivative Financial Instruments

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used by EnCana to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

EnCana 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 market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) Recent Accounting Pronouncements

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2007, the Company is required to adopt the Canadian Institute of Chartered Accountants ("CICA") Section 1530 "*Comprehensive Income*", Section 3251 "*Equity*", Section 3855 "*Financial Instruments – Recognition and Measurement*", and Section 3865 "*Hedges*", which were issued in January 2005. Under the new standards, comprehensive income has been introduced which will provide for certain gains and losses, including foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside of net earnings. In addition, all financial instruments, including derivatives, are to be included in the Company's Consolidated Balance Sheet and measured, in most cases, at fair values, and requirements for hedge accounting have been further clarified.

  The Company does not expect the Financial Instruments and Hedges standards to have a material impact on its Consolidated Financial Statements as EnCana currently uses mark-to-market accounting for derivative instruments that do not qualify or are not designated as hedges. As a result of these new standards, the Company's financial statement presentation will change to be similar to the presentation under the United States Accounting Principles and Reporting included in Note 20.
- As of January 1, 2007, EnCana is required to adopt revised CICA Section 1506, "*Accounting Changes*", which provides expanded disclosures for changes in accounting polices, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information. EnCana does not expect application of this revised standard to have a material impact on its Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt two new CICA standards, Section 3862 "*Financial Instruments – Disclosures*" and Section 3863 "*Financial Instruments – Presentation*", which will replace Section 3861 "*Financial Instruments – Disclosure and Presentation*". The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.

- As of January 1, 2008, EnCana will be required to adopt CICA Section 1535 "*Capital Disclosures*", which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its Consolidated Financial Statements.
- In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2006.

2. Changes 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 year ended December 31, 2006 include offsets of $3,238 million.

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 markets substantially all of the Company's North American Upstream production 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 years ended December 31	Upstream 2006	Upstream 2005	Upstream 2004	Market Optimization 2006	Market Optimization 2005	Market Optimization 2004
Revenues, Net of Royalties	**$11,342**	$10,772	$ 7,488	**$ 3,007**	$ 4,267	$ 3,200
Expenses						
Production and mineral taxes	**349**	453	311	**–**	–	–
Transportation and selling	**1,054**	832	704	**16**	13	18
Operating	**1,605**	1,351	1,026	**62**	85	74
Purchased product	**–**	–	–	**2,862**	4,159	3,092
Depreciation, depletion and amortization	**3,025**	2,688	2,271	**12**	8	47
Segment Income (Loss)	**$ 5,309**	$ 5,448	$ 3,176	**$ 55**	$ 2	$ (31)

	Corporate 2006	Corporate 2005	Corporate 2004	Consolidated 2006	Consolidated 2005	Consolidated 2004
Revenues, Net of Royalties	**$ 2,050**	$ (466)	$ (197)	**$16,399**	$14,573	$10,491
Expenses						
Production and mineral taxes	**–**	–	–	**349**	453	311
Transportation and selling	**–**	–	–	**1,070**	845	722
Operating	**(12)**	2	(1)	**1,655**	1,438	1,099
Purchased product	**–**	–	–	**2,862**	4,159	3,092
Depreciation, depletion and amortization	**75**	73	61	**3,112**	2,769	2,379
Segment Income (Loss)	**$ 1,987**	$ (541)	$ (257)	**7,351**	4,909	2,888
Administrative				**271**	268	197
Interest, net				**396**	524	398
Accretion of asset retirement obligation				**50**	37	22
Foreign exchange (gain) loss, net				**14**	(24)	(412)
Stock-based compensation – options				**–**	15	17
(Gain) on divestitures				**(323)**	–	(59)
				408	820	163
Net Earnings Before Income Tax				**6,943**	4,089	2,725
Income tax expense				**1,892**	1,260	632
Net Earnings From Continuing Operations				**$ 5,051**	$ 2,829	$ 2,093

Upstream

For the years ended December 31	Canada 2006	Canada 2005	Canada 2004	United States 2006	United States 2005	United States 2004
Revenues, Net of Royalties	**$ 7,911**	$ 7,312	$ 5,315	**$ 3,121**	$ 3,177	$ 1,941
Expenses						
Production and mineral taxes	**116**	104	87	**233**	349	224
Transportation and selling	**806**	650	584	**248**	182	120
Operating	**1,029**	826	685	**283**	212	119
Depreciation, depletion and amortization	**2,142**	1,927	1,751	**848**	682	475
Segment Income	**$ 3,818**	$ 3,805	$ 2,208	**$ 1,509**	$ 1,752	$ 1,003

	Other 2006	Other 2005	Other 2004	Total Upstream 2006	Total Upstream 2005	Total Upstream 2004
Revenues, Net of Royalties	**$ 310**	$ 283	$ 232	**$11,342**	$10,772	$ 7,488
Expenses						
Production and mineral taxes	**–**	–	–	**349**	453	311
Transportation and selling	**–**	–	–	**1,054**	832	704
Operating	**293**	313	222	**1,605**	1,351	1,026
Depreciation, depletion and amortization	**35**	79	45	**3,025**	2,688	2,271
Segment Income (Loss)	**$ (18)**	$ (109)	$ (35)	**$ 5,309**	$ 5,448	$ 3,176

Upstream Geographic and Product Information (Continuing Operations)

Produced Gas									
	Canada			United States			Total		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 5,440**	$ 5,486	$ 3,928	**$ 2,854**	$ 2,932	$ 1,776	**$ 8,294**	$ 8,418	$ 5,704
Expenses									
Production and mineral taxes	**80**	76	65	**213**	325	205	**293**	401	270
Transportation and selling	**278**	283	296	**248**	182	120	**526**	465	416
Operating	**629**	521	400	**283**	212	119	**912**	733	519
Operating Cash Flow	**$ 4,453**	$ 4,606	$ 3,167	**$ 2,110**	$ 2,213	$ 1,332	**$ 6,563**	$ 6,819	$ 4,499

Oil and NGLs									
	Canada			United States			Total		
	2006	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 2,471**	$ 1,826	$ 1,387	**$ 267**	$ 245	$ 165	**$ 2,738**	$ 2,071	$ 1,552
Expenses									
Production and mineral taxes	**36**	28	22	**20**	24	19	**56**	52	41
Transportation and selling	**528**	367	288	**—**	—	—	**528**	367	288
Operating	**400**	305	285	**—**	—	—	**400**	305	285
Operating Cash Flow	**$ 1,507**	$ 1,126	$ 792	**$ 247**	$ 221	$ 146	**$ 1,754**	$ 1,347	$ 938

	Other			Total Upstream		
	2006	2005	2004	**2006**	2005	2004
Revenues, Net of Royalties	**$ 310**	$ 283	$ 232	**$ 11,342**	$ 10,772	$ 7,488
Expenses						
Production and mineral taxes	**—**	—	—	**349**	453	311
Transportation and selling	**—**	—	—	**1,054**	832	704
Operating	**293**	313	222	**1,605**	1,351	1,026
Operating Cash Flow	**$ 17**	$ (30)	$ 10	**$ 8,334**	$ 8,136	$ 5,447

Capital Expenditures (Continuing Operations)

For the years ended December 31	**2006**	2005	2004
Upstream Core Capital			
Canada	**$ 4,015**	$ 4,150	$ 3,015
United States	**2,061**	1,982	1,249
Other Countries	**75**	70	79
	6,151	6,202	4,343
Upstream Acquisition Capital			
Canada	**47**	30	64
United States	**284**	418	300
	331	448	364
Market Optimization	**44**	197	10
Corporate	**74**	78	46
Total	**$ 6,600**	$ 6,925	$ 4,763

On December 17, 2004, EnCana acquired certain natural gas and crude oil properties in Texas for approximately $251 million. The purchase was facilitated by an unrelated party, Brown Ranger LLC, which held the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, EnCana operated the properties, received all the revenue and paid all of the expenses associated with the properties. EnCana determined that the relationship with Brown Ranger LLC represented an interest in a variable interest entity ("VIE") and that EnCana was the primary beneficiary of the VIE. EnCana consolidated Brown Ranger LLC from the date of acquisition to the date the properties were transferred to EnCana in 2005.

Additions to Goodwill

There were no additions to goodwill during 2006 or 2005. All goodwill included in continuing operations relates to the Upstream segment.

Property, Plant and Equipment and Total Assets

		Property, Plant and Equipment		Total Assets	
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

Export Sales

Sales of natural gas, crude oil and NGLs produced or purchased in Canada delivered to customers outside of Canada were $1,814 million (2005 – $1,784 million; 2004 – $1,747 million).

Major Customers

In connection with the marketing and sale of EnCana's own and purchased natural gas and crude oil, for the year ended December 31, 2006, the Company had one customer (2005 – one) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to this customer, a major international integrated energy company with a high quality investment grade credit rating, were approximately $1,951 million (2005 – $2,056 million).

4. Discontinued Operations

As EnCana has focused its continuing operations on North American Upstream operations, a number of divestitures have been made which are accounted for as discontinued operations.

Midstream

During 2006, EnCana completed, in two separate transactions with a single purchaser, the sale of its natural gas storage operations in Canada and the United States. Total proceeds received were approximately $1.5 billion and an after-tax gain on sale of $829 million was recorded.

On December 13, 2005, EnCana completed the sale of its natural gas liquids processing operations for proceeds of $625 million (C$720 million) and recorded an after-tax gain on sale of $370 million.

Upstream

Ecuador

On February 28, 2006, EnCana completed the sale of its Ecuador operations for proceeds of $1.4 billion before indemnifications. A loss of $279 million, including the impact of indemnifications, was recorded. Indemnifications are discussed further in this note.

Amounts recorded as depreciation, depletion and amortization in 2006 and 2005 represent provisions which were recorded against the net book value of the Ecuador operations to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments, as required by Canadian generally accepted accounting principles.

United Kingdom

On December 1, 2004, EnCana completed the sale of its 100 percent interest in EnCana (U.K.) Limited, holder of its U.K. operations, for net cash consideration of approximately $2.1 billion. A gain on sale of approximately $1.4 billion was recorded.

Consolidated Statement of Earnings

The following tables present the effect of the discontinued operations in the Consolidated Statement of Earnings:

Midstream

For the years ended December 31	**2006**	2005	2004
Revenues	**$ 482**	$ 1,570	$ 1,551
Expenses			
Transportation and selling	**–**	9	9
Operating	**37**	301	251
Purchased product	**356**	1,100	1,184
Depreciation, depletion and amortization	**–**	28	23
Administrative	**–**	30	–
Interest, net	**–**	(2)	(1)
Foreign exchange (gain) loss, net	**4**	(2)	(5)
(Gain) on discontinuance	**(807)**	(364)	(54)
	(410)	1,100	1,407
Net Earnings Before Income Tax	**892**	470	144
Income tax expense	**17**	39	26
Net Earnings From Discontinued Operations	**$ 875**	$ 431	$ 118

Upstream – Ecuador

For the years ended December 31	2006	2005	2004
Revenues, Net of Royalties	**$ 200**	$ 965	$ 471
Expenses			
Production and mineral taxes	**23**	131	61
Transportation and selling	**10**	58	60
Operating	**25**	138	125
Depreciation, depletion and amortization	**84**	234	263
Interest, net	**(2)**	(2)	(3)
Accretion of asset retirement obligation	**–**	1	1
Foreign exchange (gain) loss, net	**1**	(4)	5
Loss on discontinuance	**279**	–	–
	420	556	512
Net Earnings (Loss) Before Income Tax	**(220)**	409	(41)
Income tax expense (recovery)	**59**	278	(8)
Net Earnings (Loss) From Discontinued Operations	**$ (279)**	$ 131	$ (33)

Upstream – United Kingdom

For the years ended December 31	2006	2005	2004
Revenues, Net of Royalties	**$ –**	$ –	$ 153
Expenses			
Transportation and selling	**–**	–	36
Operating	**–**	–	36
Depreciation, depletion and amortization	**–**	–	118
Interest, net	**–**	–	(9)
Accretion of asset retirement obligation	**–**	–	3
Foreign exchange (gain) loss, net	**(1)**	(40)	(2)
(Gain) on discontinuance	**–**	–	(1,365)
	(1)	(40)	(1,183)
Net Earnings (Loss) Before Income Tax	**1**	40	1,336
Income tax expense (recovery)	**(4)**	5	(2)
Net Earnings From Discontinued Operations	**$ 5**	$ 35	$ 1,338

Upstream – Syncrude

For the years ended December 31	2006	2005	2004
Revenues, Net of Royalties	**$ –**	$ –	$ (1)
Expenses			
Loss on discontinuance	**–**	–	2
	–	–	2
Net (Loss) Before Income Tax	**–**	–	(3)
Income tax expense	**–**	–	–
Net (Loss) From Discontinued Operations	**$ –**	$ –	$ (3)

Consolidated Total

For the years ended December 31	2006	2005	2004
Revenues, Net of Royalties	$ 682	$ 2,535	$ 2,174
Expenses			
Production and mineral taxes	23	131	61
Transportation and selling	10	67	105
Operating	62	439	412
Purchased product	356	1,100	1,184
Depreciation, depletion and amortization	84	262	404
Administrative	—	30	—
Interest, net	(2)	(4)	(13)
Accretion of asset retirement obligation	—	1	4
Foreign exchange (gain) loss, net	4	(46)	(2)
(Gain) on discontinuance	(528)	(364)	(1,417)
	9	1,616	738
Net Earnings Before Income Tax	673	919	1,436
Income tax expense	72	322	16
Net Earnings From Discontinued Operations	$ 601	$ 597	$ 1,420
Net Earnings from Discontinued Operations per Common Share			
Basic	$ 0.73	$ 0.69	$ 1.55
Diluted	$ 0.72	$ 0.67	$ 1.51

Consolidated Balance Sheet

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

As at December 31	2006	2005
Assets		
Cash and cash equivalents	$ –	$ 208
Accounts receivable and accrued revenues	–	408
Risk management	–	21
Inventories	–	413
	–	1,050
Property, plant and equipment, net	–	1,686
Investments and other assets	–	360
Goodwill	–	67
	$ –	$ 3,163
Liabilities		
Accounts payable and accrued liabilities	$ –	$ 167
Income tax payable	–	230
Risk management	–	41
	–	438
Asset retirement obligation	–	21
Future income taxes	–	246
	–	705
Net Assets of Discontinued Operations	$ –	$ 2,458

Included in Midstream is $nil (2005 – $117 million) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Divestitures

On December 22, 2004, EnCana completed the divestiture of its interest in the Alberta Ethane Gathering System Joint Venture for approximately $108 million, including working capital. A $54 million pre-tax gain was recorded on this sale.

Commitments and Contingencies

EnCana has 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 calculated in accordance with the terms of the agreements, 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

For the years ended December 31	**2006**	2005	2004
Upstream	**$ 445**	$ 2,521	$ 1,430
Market Optimization	**244**	—	26
Other	**—**	2	44
	$ 689	$ 2,523	$ 1,500

Proceeds received on the sale of assets and investments in 2006 were $689 million (2005 – $2,523 million; 2004 – $1,500 million) as described below:

Upstream

In 2006, EnCana completed the divestiture of various mature conventional oil and natural gas assets for proceeds of $78 million (2005 – $471 million; 2004 – $1,430 million).

In August 2006, EnCana 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, EnCana 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.

In December 2004, EnCana sold its 25 percent limited partnership interest in the Kingston CoGen Limited Partnership ("Kingston") for net cash consideration of $25 million. A pre-tax gain of $28 million was recorded on this sale.

Other

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

6. Interest, Net

For the years ended December 31	2006	2005	2004
Interest Expense – Long-Term Debt	$ 366	$ 417	$ 385
Early Retirement of Long-Term Debt	–	121	(16)
Interest Expense – Other	76	18	42
Interest Income	(46)	(32)	(13)
	$ 396	$ 524	$ 398

During 2005, EnCana redeemed a number of unsecured notes with a principal of C$1,150 million. The $121 million before tax ($79 million after-tax) charge is due to the early retirement of these medium term notes.

EnCana has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions detailed below (see Note 12). The net effect of these transactions reduced interest costs in 2006 by $7 million (2005 – $16 million; 2004 – $22 million).

Swap Positions As at December 31, 2006	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
5.80% due June 2, 2008	US$71 million	C$ Fixed	US$ Fixed*	4.80%
C$225 million				
	C$125 million	C$ Fixed	C$ Floating	3 month Bankers' Acceptance less 5 basis points

* This instrument has been subject to multiple swap transactions.

7. Foreign Exchange (Gain) Loss, Net

For the years ended December 31	2006	2005	2004
Unrealized Foreign Exchange (Gain) on Translation of U.S. Dollar Debt Issued from Canada	$ –	$ (113)	$ (285)
Other Foreign Exchange (Gain) Loss	14	89	(127)
	$ 14	$ (24)	$ (412)

8. Income Taxes

The provision for income taxes is as follows:

For the years ended December 31	2006	2005	2004
Current			
Canada	$ 764	$ 493	$ 586
United States	128	719	(12)
Other	50	(8)	(15)
Total Current Tax	942	1,204	559
Future	1,407	56	182
Future Tax Rate Reductions	(457)	—	(109)
Total Future Tax	950	56	73
	$ 1,892	$ 1,260	$ 632

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:

For the years ended December 31	2006	2005	2004
Net Earnings Before Income Tax	$ 6,943	$ 4,089	$ 2,725
Canadian Statutory Rate	34.7%	37.9%	39.1%
Expected Income Tax	2,407	1,550	1,066
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	97	207	192
Canadian resource allowance	(16)	(202)	(256)
Statutory and other rate differences	(98)	(235)	(50)
Effect of tax rate changes	(457)	—	(109)
Non-taxable capital gains	(1)	(24)	(91)
Previously unrecognized capital losses	—	—	17
Tax basis retained on divestitures	—	(68)	(169)
Large corporations tax	—	25	24
Other	(40)	7	8
	$ 1,892	$ 1,260	$ 632
Effective Tax Rate	27.3%	30.8%	23.2%

The net future income tax liability is comprised of:

As at December 31	2006	2005
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	$ 4,695	$ 4,461
Timing of partnership items	1,251	1,226
Other	305	—
Future Tax Assets		
Non-capital and net operating losses carried forward	(11)	(47)
Other	—	(351)
Net Future Income Tax Liability	$ 6,240	$ 5,289

The approximate amounts of tax pools available are as follows:

As at December 31	2006	2005
Canada	$ 9,352	$ 8,575
United States	3,409	2,978
	$ 12,761	$ 11,553

Included in the above tax pools are $39 million (2005 – $133 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire between 2008 and 2016.

The current income tax provision includes amounts payable or recoverable in respect of Canadian partnership earnings included in the Consolidated Financial Statements for partnerships that have a year end that is after that of EnCana Corporation.

9. Inventories

As at December 31	2006	2005
Product		
Upstream	$ 50	$ 70
Market Optimization	126	31
Parts and Supplies	—	2
	$ 176	$ 103

10. Property, Plant and Equipment, Net

As at December 31	2006			2005		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream						
Canada	$ 33,289	$(14,265)	$ 19,024	$ 29,199	$(12,144)	$ 17,055
United States	11,105	(2,611)	8,494	8,707	(1,763)	6,944
Other Countries	360	(97)	263	470	(222)	248
Total Upstream	44,754	(16,973)	27,781	38,376	(14,129)	24,247
Market Optimization	207	(53)	154	419	(48)	371
Corporate	616	(338)	278	544	(281)	263
	$ 45,577	$(17,364)	$ 28,213	$ 39,339	$(14,458)	$ 24,881

* Depreciation, depletion and amortization

Upstream property, plant and equipment include internal costs directly related to exploration, development and construction activities of $365 million (2005 – $347 million). Costs classified as Administrative expenses have not been capitalized as part of the capital expenditures.

Upstream costs in respect of significant unproved properties and major development projects excluded from depletable costs at the end of the year were:

As at December 31	**2006**	2005	2004
Canada	**$ 1,449**	$ 1,689	$ 1,444
United States	**956**	870	1,119
Other Countries	**263**	248	177
	$ 2,668	$ 2,807	$ 2,740

The costs excluded from depletable costs in Other Countries represent costs related to unproved properties incurred in cost centres that are considered to be in the pre-production stage. Currently, there are no proved reserves in these cost centres. All costs, net of any associated revenues, in these cost centres have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. For the year ended December 31, 2006, the Company completed its impairment review of pre-production cost centres and determined that $6 million of costs should be charged to the Consolidated Statement of Earnings (2005 – $7 million; 2004 – $23 million).

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2006 were:

	2007	2008	2009	2010	2011	Cumulative % Increase to 2018
Natural Gas ($/Mcf)						
Canada	$ 5.93	$ 6.09	$ 5.65	$ 5.71	$ 5.77	16%
United States	$ 6.75	$ 6.43	$ 6.27	$ 6.40	$ 6.36	14%
Crude Oil ($/barrel)						
Canada	$ 28.99	$ 28.00	$ 27.58	$ 28.12	$ 28.48	5%
Natural Gas Liquids ($/barrel)						
Canada	$ 46.80	$ 47.09	$ 49.36	$ 50.41	$ 51.40	15%
United States	$ 43.12	$ 42.84	$ 45.06	$ 45.95	$ 47.12	14%

11. Investments and Other Assets

As at December 31	**2006**	2005
Prepaid Capital	**$ 401**	$ 334
Deferred Pension Plan and Savings Plan	**58**	60
Deferred Financing Costs	**52**	59
Marketing Contracts	**—**	10
Equity Investment	**6**	7
Other	**16**	26
	$ 533	$ 496

12. Long-Term Debt

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

A) Overview

Revolving Credit and Term Loan Borrowings

At December 31, 2006, EnCana Corporation had in place a revolving credit facility for C$4.5 billion or its equivalent amount in U.S. dollars ($3.9 billion). The facility, which matures in October 2011, is fully revolving for a period of five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus ninety days from the date of the extension request, at the option of the lenders and upon notice from EnCana. The facility is unsecured and bears interest at the lenders' rates for Canadian prime, U.S. base rate, Bankers' Acceptances rates plus applicable margins, or at LIBOR plus applicable margins.

At December 31, 2006, one of EnCana's subsidiaries had in place a credit facility totaling $600 million. The facility, which matures in February 2012, is guaranteed by EnCana Corporation, and is fully revolving for five years. The facility is extendible from time to time, but not more than once per year, for a period not longer than five years plus ninety days from the date of the extension request, at the option of the lenders and upon notice from the subsidiary. This facility bears interest at either the lenders' U.S. base rate or at LIBOR plus applicable margins.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper of $1,560 million (2005 – $1,425 million) maturing at various dates with a weighted average interest rate of 4.58 percent (2005 – 3.52 percent). These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2006 relating to revolving credit and term loan agreements were approximately $5 million (2005 – $4 million; 2004 – $5 million).

Unsecured Notes

Unsecured notes include medium term notes and senior notes that are issued from time to time under trust indentures.

EnCana has in place a debt shelf prospectus for Canadian unsecured medium term notes in the amount of C$1 billion. The shelf prospectus provides that debt securities in Canadian dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and maturity dates are determined by reference to market conditions at the date of issue. At December 31, 2006, C$500 million ($429 million) of the shelf prospectus, which expires in September 2007, remains unutilized, the availability of which is dependent upon market conditions.

EnCana has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the multijurisdictional disclosure system ("MJDS"). The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. The shelf prospectus was renewed in 2006 and expires in October 2008. At December 31, 2006, $2 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

EnCana has an indirect wholly owned subsidiary, EnCana Holdings Finance Corp., which has in place a debt shelf prospectus for U.S. unsecured notes in the amount of $2 billion under the MJDS. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates are determined by reference to market conditions at the date of issue. The debt securities issued under this shelf prospectus are fully and unconditionally guaranteed by EnCana Corporation. EnCana has also obtained certain exemption orders from Canadian securities regulatory authorities that allow the filing of certain financial and other information of EnCana to satisfy certain continuous disclosure obligations of EnCana Holdings Finance Corp. The shelf prospectus was renewed in 2006 and expires in July 2008. At December 31, 2006, $2 billion of the shelf prospectus remains unutilized, the availability of which is dependent upon market conditions.

B) Canadian Revolving Credit and Term Loan Borrowings

	C$ Principal Amount	2006	2005
Bankers' Acceptances	$ 390	$ 335	$ 369
Commercial Paper	1,306	1,121	1,056
	$ 1,696	$ 1,456	$ 1,425

C) Canadian Unsecured Notes

	C$ Principal Amount	2006	2005
5.30% due December 3, 2007	$ 300	$ 257	$ 257
5.80% due June 2, 2008	125	107	107
3.60% due September 15, 2008	500	429	429
	$ 925	$ 793	$ 793

D) U.S. Revolving Credit and Term Loan Borrowings

	2006	2005
Commercial Paper	$ 104	$ —

E) U.S. Unsecured Notes

	C$ Amount	2006	2005
7.50% due August 25, 2006	$ —	$ —	$ 73
5.80% due June 2, 2008	83*	71	71
4.60% due August 15, 2009		250	250
7.65% due September 15, 2010		200	200
6.30% due November 1, 2011		500	500
4.75% due October 15, 2013		500	500
5.80% due May 1, 2014		1,000	1,000
8.125% due September 15, 2030		300	300
7.20% due November 1, 2031		350	350
7.375% due November 1, 2031		500	500
6.50% due August 15, 2034		750	750
		$ 4,421	$ 4,494

* The Company has entered into a cross-currency and interest rate swap transaction that effectively converts a portion of the Canadian dollar denominated note to U.S. dollars. The effective U.S. dollar principal is shown in the table.

The 5.80% note due May 1, 2014 was issued by the Company's indirect wholly owned subsidiary, EnCana Holdings Finance Corp. This note is fully and unconditionally guaranteed by EnCana Corporation.

F) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 21 years.

G) Current Portion of Long-Term Debt

	C$ Principal Amount	2006	2005
7.50% medium term note due August 25, 2006	$ —	$ —	$ 73
5.30% medium term note due December 3, 2007	300	257	—
	$ 300	$ 257	$ 73

H) Mandatory Debt Payments

	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2007	$ 300	$ —	$ 257
2008	625	71	607
2009	—	250	250
2010	—	200	200
2011	1,696	604	2,060
Thereafter	—	3,400	3,400
Total	$ 2,621	$ 4,525	$ 6,774

The amount due in 2007 excludes Bankers' Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

13. 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	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

The total undiscounted amount of estimated cash flows required to settle the obligation is $5,334 million (2005 – $4,944 million), which has been discounted using a weighted average credit-adjusted risk free rate of 5.66 percent (2005 – 5.74 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources at that time.

14. Share Capital

Authorized

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.

Issued and Outstanding

As at December 31	2006		2005	
	Number (millions)	Amount	Number (millions)	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 $4,219 million. Of the amount paid, $734 million was charged to Share capital and $3,485 million was charged to Retained earnings. Included in the 2005 Common Shares Purchased are 5.5 million Common Shares which have been purchased by an EnCana Employee Benefit Plan Trust and are held for issuance upon vesting under EnCana's Performance Share Unit Plan (see Note 15).

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. During January 2007, EnCana purchased approximately 10.8 million Common Shares under the Bid for total consideration of $494 million.

Stock Options

EnCana 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 10 years from the date the options were granted. All options issued subsequent to December 31, 2003 have an associated Tandem Share Appreciation Right ("TSAR") attached to them (see Note 15).

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase EnCana Common Shares. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted.

Canadian Pacific Limited Replacement Plan

As part of the 2001 reorganization of Canadian Pacific Limited ("CPL"), EnCana's former parent company, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and are all exercisable.

Directors' Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors were given an initial grant of 15,000 options to purchase common shares of the Company. Thereafter, there was an annual grant of 7,500 options to each non-employee director. Options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date. On October 23, 2003, issuances of stock options under this plan were discontinued and on October 25, 2005, the Company terminated the plan.

The following tables summarize the information about options to purchase Common Shares that do not have a TSAR attached to them:

As at December 31	2006		2005		2004	
	Stock Options (millions)	Weighted Average Exercise Price (C$)	Stock Options (millions)	Weighted Average Exercise Price (C$)	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	**20.7**	**23.36**	36.2	23.15	57.6	21.57
Exercised	**(8.6)**	**23.60**	(14.9)	22.90	(19.4)	18.32
Forfeited	**(0.3)**	**23.80**	(0.6)	21.71	(2.0)	23.75
Outstanding, End of Year	**11.8**	**23.17**	20.7	23.36	36.2	23.15
Exercisable, End of Year	**11.8**	**23.17**	16.8	23.21	21.6	22.55

As at December 31, 2006	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, there were 20.7 million common shares reserved for issuance under stock option plans (2005 – 29.3 million; 2004 – 16.0 million).

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 subsequent to December 31, 2003 have an associated TSAR 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 in 2006 and 2005 would have been unchanged (2004 – $3,476 million; $3.77 per common share – basic; $3.71 per common share – diluted).

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

For the year ended December 31	2003
Weighted Average Fair Value of Options Granted (C$)	$ 6.11
Risk-Free Interest Rate	3.87%
Expected Lives (years)	3.00
Expected Volatility	0.33
Annual Dividend per Share (C$/common share)	$ 0.20

At December 31, 2006 and 2005, the balance in Paid in surplus relates to stock-based compensation programs.

15. Compensation Plans

Where applicable, the amounts below have been restated to reflect the effect of the common share split approved in April 2005.

A) Pensions and Post-Employment Benefits

The most recent actuarial valuation completed for the Company's pension plans is dated December 31, 2005. The next required valuation will be as at December 31, 2008.

The Company sponsors both defined benefit and defined contribution plans, providing pension and post-employment benefits ("OPEB") to substantially all of its employees.

For the years ended December 31	**2006**	2005	2004
Total Expense for Defined Contribution Plans	**$ 28**	$ 22	$ 19

Information about defined benefit and OPEB plans, in aggregate, is as follows:

Accrued Benefit Obligation

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Accrued Benefit Obligation, Beginning of Year	**$ 294**	$ 246	**$ 39**	$ 19
Amendments	**—**	—	**—**	13
Current service cost	**9**	6	**7**	5
Interest cost	**15**	14	**2**	2
Benefits paid	**(18)**	(12)	**(1)**	(1)
Actuarial (gain) loss	**7**	29	**(2)**	—
Contributions	**1**	1	**—**	—
Foreign exchange	**—**	10	**—**	1
Accrued Benefit Obligation, End of Year	**$ 308**	$ 294	**$ 45**	$ 39

The amendments made January 1, 2005 related to obligations for OPEB related to the acquisition of Tom Brown, Inc. and changes made to one of the Company's Plans which increased the Company's OPEB obligation.

Plan Assets

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Fair Value of Plan Assets, Beginning of Year	**$ 284**	$ 247	**$ —**	$ —
Actual return on plan assets	**27**	29	**—**	—
Employer contributions	**10**	9	**—**	—
Employees' contributions	**1**	1	**—**	—
Benefits paid	**(18)**	(12)	**—**	—
Foreign exchange	**—**	10	**—**	—
Fair Value of Plan Assets, End of Year	**$ 304**	$ 284	**$ —**	$ —

Accrued Benefit Asset (Liability)

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Funded Status – Plan Assets (less) than Benefit Obligation	**$ (4)**	$ (10)	**$ (45)**	$ (39)
Amounts Not Recognized:				
Unamortized net actuarial loss	**54**	64	**2**	4
Unamortized past service cost	**7**	9	**1**	1
Net transitional asset	**(6)**	(8)	**13**	14
Accrued Benefit Asset (Liability)	**$ 51**	$ 55	**$ (29)**	$ (20)

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Prepaid Benefit Cost	**$ 51**	$ 55	**$ —**	$ —
Accrued Benefit Cost	**—**	—	**(29)**	(20)
Net Amount Recognized	**$ 51**	$ 55	**$ (29)**	$ (20)

The Company's OPEB plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

	Pension Benefits		OPEB	
As at December 31	**2006**	2005	**2006**	2005
Discount Rate	**5.00%**	5.00%	**5.375%**	5.25%
Rate of Compensation Increase	**4.30%**	4.50%	**5.65%**	5.65%

The weighted average assumptions used to determine periodic expense are as follows:

	Pension Benefits		OPEB	
For the years ended December 31	**2006**	2005	**2006**	2005
Discount Rate	**5.00%**	5.75%	**5.25%**	5.75%
Expected Long-Term Rate of Return on Plan Assets:				
Registered pension plans	**6.75%**	6.75%	**n/a**	n/a
Supplemental pension plans	**3.375%**	3.375%	**n/a**	n/a
Rate of Compensation Increase	**4.50%**	4.60%	**5.65%**	5.65%

The periodic expense for benefits is as follows:

	Pension Benefits			OPEB		
For the years ended December 31	**2006**	2005	2004	**2006**	2005	2004
Current Service Cost	**$ 9**	$ 6	$ 5	**$ 7**	$ 5	$ 1
Interest Cost	**15**	14	13	**2**	2	1
Actual Return on Plan Assets	**(27)**	(29)	(19)	**—**	—	—
Actuarial Loss on Accrued Benefit Obligation	**6**	29	8	**—**	—	1
Difference Between Actual and:						
Expected return on plan assets	**11**	15	7	**—**	—	—
Recognized actuarial gain (loss)	**—**	(24)	(4)	**—**	—	(1)
Difference Between Amortization of Past Service Costs and Actual Plan Amendments	**2**	2	2	**—**	—	—
Amortization of Transitional Obligation	**(3)**	(3)	(2)	**2**	1	—
Expense for Defined Contribution Plan	**28**	22	19	**—**	—	—
Net Benefit Plan Expense	**$ 41**	$ 32	$ 29	**$ 11**	$ 8	$ 2

The average remaining service period of the active employees covered by the defined benefit pension plan is seven years. The average remaining service period of the active employees covered by the OPEB plan is 12 years.

Assumed health care cost trend rates are as follows:

As at December 31	2006	2005
Health Care Cost Trend Rate for Next Year	**11.00%**	11.00%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2015**	2015

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
Effect on Total of Service and Interest Cost	$ 1	$ (1)
Effect on Post Retirement Benefit Obligation	$ 4	$ (4)

The Company's pension plan asset allocations are as follows:

Asset Category	Target Allocation %		% of Plan Assets at December 31		Expected Long-Term Rate of Return
	Normal	Range	2006	2005	
Domestic Equity	35	25-45	**39**	41	
Foreign Equity	30	20-40	**30**	27	
Bonds	30	20-40	**25**	25	
Real Estate and Other	5	0-20	**6**	7	
Total	100		**100**	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company's contributions to the pension plans are subject to direction by the Pension Committee. Contributions by the participants to the pension and other benefits plans were $1 million for the year ended December 31, 2006 (2005 – $1 million; 2004 – $1 million).

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2007	$ 14	$ 1
2008	15	1
2009	16	2
2010	17	2
2011	18	3
2012 – 2016	104	29
Total	$ 184	$ 38

B) Share Appreciation Rights

EnCana has in place a program whereby certain employees are granted Share Appreciation Rights ("SAR's") which entitle the employee to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right. SAR's granted generally expire after five years with the exception of a limited number that expire after seven years.

The following tables summarize the information about the SAR's:

As at December 31	2006		2005	
	Outstanding SAR's	**Weighted Average Exercise Price**	Outstanding SAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**246,739**	**23.13**	930,510	18.31
Exercised	**(246,739)**	**23.13**	(682,241)	16.55
Forfeited	**–**	**–**	(1,530)	23.14
Outstanding, End of Year	**–**	**–**	246,739	23.13
Exercisable, End of Year	**–**	**–**	246,739	23.13
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**319,511**	**14.33**	771,860	14.40
Exercised	**(317,423)**	**14.33**	(452,349)	14.45
Outstanding, End of Year	**2,088**	**14.21**	319,511	14.33
Exercisable, End of Year	**2,088**	**14.21**	319,511	14.33

As at December 31, 2006	SAR's Outstanding and Exercisable		
Range of Exercise Price	**Number of SAR's**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**
U.S. Dollar Denominated (US$)			
10.00 to 19.99	**2,088**	**1.12**	**14.21**
	2,088	**1.12**	**14.21**

During the year, the Company recorded a reduction of $1 million to compensation costs related to the outstanding SAR's (2005 – compensation costs of $17 million; 2004 – compensation costs of $17 million).

C) Tandem Share Appreciation Rights

Subsequent to December 31, 2003, all options to purchase Common Shares issued under the share option plans described in Note 14 have an associated Tandem Share Appreciation Right ("TSAR") attached to them whereby the option holder has the right to receive a cash payment equal to the excess of the market price of EnCana's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSAR's vest and expire under the same terms and conditions as the underlying option.

The following tables summarize the information about the TSAR's:

As at December 31	2006		2005	
	Outstanding TSAR's	Weighted Average Exercise Price	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**8,403,967**	**38.41**	1,735,000	27.77
Granted	**11,180,800**	**49.01**	7,581,412	40.14
Exercised – SAR's	**(700,418)**	**34.54**	(151,610)	27.51
Exercised – Options	**(32,948)**	**34.46**	(104,735)	27.60
Forfeited	**(1,575,210)**	**43.21**	(656,100)	34.44
Outstanding, End of Year	**17,276,191**	**44.99**	8,403,967	38.41
Exercisable, End of Year	**1,971,467**	**38.31**	229,705	28.00

As at December 31, 2006	Outstanding TSAR's			Exercisable Options with TSAR's Attached	
Range of Exercise Price (C$)	Number of TSAR's	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number of TSAR's	Weighted Average Exercise Price
20.00 to 29.99	**698,118**	**2.35**	**27.41**	**293,718**	**27.44**
30.00 to 39.99	**5,253,063**	**3.12**	**38.12**	**1,427,189**	**38.07**
40.00 to 49.99	**9,645,615**	**4.09**	**48.11**	**85,780**	**44.73**
50.00 to 59.99	**1,476,335**	**4.21**	**55.04**	**143,930**	**55.22**
60.00 to 69.99	**203,060**	**4.33**	**61.93**	**20,850**	**64.19**
	17,276,191	**3.74**	**44.99**	**1,971,467**	**38.31**

During the year, the Company recorded compensation costs of $52 million related to the outstanding TSAR's (2005 – $60 million; 2004 – $3 million).

D) Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSU's"), which are equivalent in value to a common share of the Company. DSU's granted to Directors vest immediately. DSU's granted to Senior Executives in 2002 vest over a three year period. DSU's expire on December 15th of the year following the employee's retirement or death.

As at December 31	2006		2005	
	Outstanding DSU's	Average Share Price	Outstanding DSU's	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**836,561**	**26.81**	750,612	24.81
Granted, Directors	**70,000**	**56.71**	80,765	43.75
Units, in Lieu of Dividends	**12,578**	**54.69**	5,184	52.34
Exercised	**(52,562)**	**27.92**	—	—
Outstanding, End of Year	**866,577**	**29.56**	836,561	26.81
Exercisable, End of Year	**866,577**	**29.56**	836,561	26.81

During the year, the Company recorded compensation costs of $5 million related to the outstanding DSU's (2005 – $16 million; 2004 – $10 million).

E) Performance Share Units

EnCana has in place a program whereby employees may be granted Performance Share Units ("PSU's") which entitle the employee to receive, upon vesting, either a common share of EnCana or a cash payment equal to the value of one common share of EnCana depending upon the terms of the PSU granted. PSU's vest at the end of a three year period. Their ultimate value will depend upon EnCana's performance measured over three calendar years. Performance will be measured by total shareholder return relative to a fixed comparison group of North American oil and gas companies. If EnCana's performance is below the specified level compared to the comparison group, the units awarded will be forfeited. If EnCana's performance is at or above the specified level compared to the comparison group, the value of the PSU's shall be determined by EnCana's relative ranking, with payments ranging from one half to two times the PSU's granted for the 2004 and 2005 grant. These will be paid in common shares.

PSU's granted in 2003 were paid out in cash at 75 percent of the number granted.

The following table summarizes the information about the PSU's:

As at December 31	2006		2005	
	Outstanding PSU's	**Average Share Price**	Outstanding PSU's	Average Share Price
Canadian Dollar Denominated (C$)				
Outstanding, Beginning of Year	**4,704,348**	**30.65**	3,294,206	26.71
Granted	**36,599**	**54.82**	1,734,089	38.13
Paid out	**(239,794)**	**23.26**	—	—
Forfeited	**(309,313)**	**31.35**	(323,947)	30.48
Outstanding, End of Year	**4,191,840**	**31.24**	4,704,348	30.65
U.S. Dollar Denominated (US$)				
Outstanding, Beginning of Year	**739,649**	**25.22**	449,230	20.56
Granted	**4,860**	**48.07**	390,171	30.92
Forfeited	**(170,020)**	**24.13**	(99,752)	26.50
Outstanding, End of Year	**574,489**	**25.74**	739,649	25.22

During the year, the Company recorded compensation costs of $27 million related to the outstanding PSU's (2005 – $91 million; 2004 – $25 million).

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

16. Financial Instruments and Risk Management

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

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

	Realized Gain (Loss)		
For the years ended December 31	**2006**	2005	2004
Revenues, Net of Royalties	**$ 393**	$ (684)	$ (662)
Operating Expenses and Other	**5**	31	28
Gain (Loss) on Risk Management – Continuing Operations	**398**	(653)	(634)
Gain (Loss) on Risk Management – Discontinued Operations	**12**	(155)	(410)
	$ 410	$ (808)	$ (1,044)

	Unrealized Gain (Loss)		
For the years ended December 31	**2006**	2005	2004
Revenues, Net of Royalties	**$ 2,050**	$ (466)	$ (198)
Operating Expenses and Other	**10**	(3)	7
Gain (Loss) on Risk Management – Continuing Operations	**2,060**	(469)	(191)
Gain (Loss) on Risk Management – Discontinued Operations	**20**	50	(70)
	$ 2,080	$ (419)	$ (261)

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 the 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 during 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	2005
Risk Management		
Current asset	$ 1,403	$ 495
Long-term asset	133	530
Current liability	14	1,227
Long-term liability	2	102
Net Risk Management Asset (Liability) – Continuing Operations	1,520	(304)
Net Risk Management Asset (Liability) – Discontinued Operations	—	(20)
	$ 1,520	$ (324)

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

As at December 31	Note	2006	2005
Commodity Price Risk	*A*		
Natural gas		$ 1,431	$ (247)
Crude oil		74	(66)
Power		13	—
Interest Rate Risk	*B*	4	10
Credit Derivatives	*C*	(2)	(1)
Total Fair Value Positions – Continuing Operations		1,520	(304)
Total Fair Value Positions – Discontinued Operations		—	(20)
		$ 1,520	$ (324)

A) Commodity Price Risk

Natural Gas

At December 31, 2006 the Company's natural 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. Details of the contracts are as follows:

	Notional Volumes (MMcf/d)	Term	Average Price	Fair 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 (1)				2
Total Unrealized Gain on Financial Contracts				1,410
Unamortized Premiums Paid on Options				21
Total Fair Value Positions				$ 1,431

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

Crude Oil

As at December 31, 2006, the Company's crude oil risk management activities from financial contracts had an unrealized loss of $9 million and a fair market value position of $74 million. Details of the contracts are 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 (1)				–
Total Unrealized (Loss) on Financial Contracts				(9)
Unamortized Premiums Paid on Options				83
Total Fair Value Positions				$ 74

(1) Other financial positions are part of the daily 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 11 years, to manage its electricity consumption costs. At December 31, 2006, these contracts had an unrealized gain of $13 million.

B) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company's interest rate exposure on debt instruments. The impact of these transactions is described in Note 6.

The unrealized gains on the outstanding financial instruments were as follows:

	Unrealized Gain	
As at December 31	**2006**	2005
7.50% medium term note due August 25, 2006	$ –	$ 3
5.80% medium term note due June 2, 2008	4	7
	$ 4	$ 10

At December 31, 2006, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $11 million (2005 – $10 million; 2004 – $13 million).

C) Credit Risk

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Board of Directors had approved a credit policy governing the Company's credit portfolio and procedures are in place to ensure adherence to this policy.

With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings and net settlements where appropriate. At December 31, 2006, EnCana has three counterparties whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial instrument contracts by counterparty.

All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments not recorded at their fair values that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

The estimated fair values of long-term borrowings have been determined based on market information where available, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at year end.

As at December 31	**2006**		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	**$ 402**	**$ 402**	$ 105	$ 105
Accounts receivable	**1,721**	**1,721**	1,851	1,851
Financial Liabilities				
Accounts payable, income tax payable	**$ 3,420**	**$ 3,420**	$ 3,133	$ 3,133
Long-term debt	**6,834**	**6,965**	6,776	7,180

17. Supplementary Information

A) Per Share Amounts

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

For the years ended December 31	**2006**	2005	2004
Weighted Average Common Shares Outstanding – Basic	**819.9**	868.3	920.8
Effect of Stock Options and Other Dilutive Securities	**16.6**	20.9	15.2
Weighted Average Common Shares Outstanding – Diluted	**836.5**	889.2	936.0

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

B) Net Change in Non-Cash Working Capital from Continuing Operations

For the years ended December 31	**2006**	2005	2004
Operating Activities			
Accounts receivable and accrued revenues	**$ 3,128**	$ (146)	$ 825
Inventories	**(75)**	(34)	(22)
Accounts payable and accrued liabilities	**(260)**	654	585
Income tax payable	**550**	23	177
	$ 3,343	$ 497	$ 1,565
Investing Activities			
Accounts payable and accrued liabilities	**$ 19**	$ 330	$ (29)

C) Supplementary Cash Flow Information – Continuing Operations

For the years ended December 31	2006	2005	2004
Interest Paid	$ 341	$ 522	$ 402
Income Taxes Paid	$ 450	$ 1,096	$ 136

18. Commitments and Contingencies

Commitments

As at December 31, 2006	2007	2008	2009	2010	2011	Thereafter	Total
Pipeline Transportation	$ 431	$ 412	$ 424	$ 409	$ 382	$ 2,144	$ 4,202
Purchases of Goods and Services	427	282	228	161	119	790	2,007
Product Purchases	54	23	24	24	—	98	223
Operating Leases	52	46	46	50	47	237	478
Capital Commitments	75	29	6	—	—	38	148
Other Long-Term Commitments	13	7	3	2	1	—	26
Total	$ 1,052	$ 799	$ 731	$ 646	$ 549	$ 3,307	$ 7,084
Product Sales	$ 41	$ 44	$ 40	$ 42	$ 43	$ 252	$ 462

In addition to the above, the Company has made commitments related to its risk management program (see Note 16).

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 States 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.

Asset Retirement

EnCana is responsible for the retirement of long-lived assets related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company has recognized a liability of $1,051 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The operations of the Company are complex, and related tax interpretations, regulations and legislation in the various jurisdictions that EnCana operates 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.

19. 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 its Foster Creek and Christina Lake oilsands properties while ConocoPhillips contributed 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.

20. United States Accounting Principles and Reporting

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are described in this note.

Reconciliation of Net Earnings Under Canadian GAAP to U.S. GAAP

For the years ended December 31	Note	2006	2005	2004
Net Earnings – Canadian GAAP		**$ 5,652**	$ 3,426	$ 3,513
Less:				
Net Earnings From Discontinued Operations – Canadian GAAP		**601**	597	1,420
Net Earnings From Continuing Operations – Canadian GAAP		**5,051**	2,829	2,093
Increase (Decrease) in Net Earnings From Continuing Operations Under U.S. GAAP:				
Revenues, net of royalties	*A*	**179**	(217)	345
Operating	*A, D*	**(15)**	1	(3)
Depreciation, depletion and amortization	*B, D*	**95**	55	31
Administrative	*D*	**(8)**	—	—
Interest, net	*A*	**(15)**	(16)	(41)
Stock-based compensation – options	*C*	**—**	(12)	(5)
Income tax expense	*F*	**(80)**	59	(105)
Net Earnings From Continuing Operations – U.S. GAAP		**5,207**	2,699	2,315
Net Earnings From Discontinued Operations – U.S. GAAP		**644**	553	1,418
Net Earnings Before Change in Accounting Policy – U.S. GAAP		**5,851**	3,252	3,733
Cumulative Effect of Change in Accounting Policy, net of tax	*D*	**(15)**	—	—
Net Earnings – U.S. GAAP		**$ 5,836**	$ 3,252	$ 3,733
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		**$ 7.14**	$ 3.75	$ 4.05
Diluted		**$ 6.99**	$ 3.66	$ 3.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		**$ 7.12**	$ 3.75	$ 4.05
Diluted		**$ 6.98**	$ 3.66	$ 3.99

Consolidated Statement of Earnings – U.S. GAAP

For the years ended December 31	Note	2006	2005	2004
Revenues, Net of Royalties	A	**$16,578**	$14,356	$10,836
Expenses				
Production and mineral taxes		**349**	453	311
Transportation and selling		**1,070**	845	722
Operating	A, D	**1,670**	1,437	1,102
Purchased product		**2,862**	4,159	3,092
Depreciation, depletion and amortization	B, D	**3,017**	2,714	2,348
Administrative	D	**279**	268	197
Interest, net	A	**411**	540	439
Accretion of asset retirement obligation		**50**	37	22
Foreign exchange (gain) loss, net		**14**	(24)	(412)
Stock-based compensation – options	C	**—**	27	22
(Gain) on divestitures		**(323)**	—	(59)
Net Earnings Before Income Tax		**7,179**	3,900	3,052
Income tax expense	F	**1,972**	1,201	737
Net Earnings From Continuing Operations – U.S. GAAP		**5,207**	2,699	2,315
Net Earnings From Discontinued Operations – U.S. GAAP		**644**	553	1,418
Net Earnings Before Change in Accounting Policy – U.S. GAAP		**5,851**	3,252	3,733
Cumulative Effect of Change in Accounting Policy, net of tax	D	**(15)**	—	—
Net Earnings – U.S. GAAP		**$ 5,836**	$ 3,252	$ 3,733
Net Earnings From Continuing Operations per Common Share – U.S. GAAP				
Basic		**$ 6.35**	$ 3.11	$ 2.51
Diluted		**$ 6.22**	$ 3.04	$ 2.47
Net Earnings From Discontinued Operations per Common Share – U.S. GAAP				
Basic		**$ 0.79**	$ 0.64	$ 1.54
Diluted		**$ 0.77**	$ 0.62	$ 1.52
Net Earnings per Common Share Before Change in Accounting Policy – U.S. GAAP				
Basic		**$ 7.14**	$ 3.75	$ 4.05
Diluted		**$ 6.99**	$ 3.66	$ 3.99
Net Earnings per Common Share Including Cumulative Effect of Change in Accounting Policy – U.S. GAAP				
Basic		**$ 7.12**	$ 3.75	$ 4.05
Diluted		**$ 6.98**	$ 3.66	$ 3.99

Consolidated Statement of Comprehensive Income – U.S. GAAP

For the years ended December 31	Note	2006	2005	2004
Net Earnings – U.S. GAAP		**$ 5,836**	$ 3,252	$ 3,733
Change in Fair Value of Financial Instruments	A, G	**4**	—	—
Foreign Currency Translation Adjustment	E	**(224)**	573	420
Compensation Plans – Adoption of FAS 158	D	**(48)**	—	—
Comprehensive Income		**$ 5,568**	$ 3,825	$ 4,153

Consolidated Statement of Accumulated Other Comprehensive Income – U.S. GAAP

For the years ended December 31	Note	2006	2005	2004
Balance, Beginning of Year		**$ 1,598**	$ 1,025	$ 605
Change in Fair Value of Financial Instruments	A, G	**4**	—	—
Foreign Currency Translation Adjustment	E	**(224)**	573	420
Compensation Plans – Adoption of FAS 158	D	**(48)**	—	—
Balance, End of Year		**$ 1,330**	$ 1,598	$ 1,025

Consolidated Statement of Retained Earnings – U.S. GAAP

For the years ended December 31	2006	2005	2004
Retained Earnings, Beginning of Year	**$ 9,327**	$ 7,955	$ 5,076
Net Earnings	**5,836**	3,252	3,733
Dividends on Common Shares	**(304)**	(238)	(183)
Charges for Normal Course Issuer Bid	**(3,485)**	(1,642)	(671)
Retained Earnings, End of Year	**$ 11,374**	$ 9,327	$ 7,955

Condensed Consolidated Balance Sheet

As at December 31		2006		2005	
	Note	As Reported	U.S GAAP	As Reported	U.S. GAAP
Assets					
Current Assets	*D*	**$ 3,702**	**$ 3,703**	$ 3,604	$ 3,603
Property, Plant and Equipment (includes unproved properties of $2,668 and $2,807 as of December 31, 2006 and 2005, respectively)	*B, D*	**45,577**	**45,496**	39,339	39,224
Accumulated Depreciation, Depletion and Amortization		**(17,364)**	**(17,197)**	(14,458)	(14,383)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**28,213**	**28,299**	24,881	24,841
Investments and Other Assets	*D*	**533**	**488**	496	491
Risk Management		**133**	**133**	530	530
Assets of Discontinued Operations		**—**	**—**	2,113	2,113
Goodwill		**2,525**	**2,525**	2,524	2,524
		$ 35,106	**$ 35,148**	$ 34,148	$ 34,102
Liabilities and Shareholders' Equity					
Current Liabilities	*A, D*	**$ 3,691**	**$ 3,742**	$ 4,871	$ 4,821
Long-Term Debt		**6,577**	**6,577**	6,703	6,703
Other Liabilities	*A, D*	**79**	**106**	93	22
Risk Management		**2**	**2**	102	102
Asset Retirement Obligation		**1,051**	**1,051**	816	816
Liabilities of Discontinued Operations		**—**	**—**	267	267
Future Income Taxes	*F*	**6,240**	**6,189**	5,289	5,153
		17,640	**17,667**	18,141	17,884
Share Capital	*C*				
Common Shares, no par value Outstanding: 2006 – 777.9 million shares 2005 – 854.9 million shares		**4,587**	**4,617**	5,131	5,160
Paid in Surplus		**160**	**160**	133	133
Retained Earnings		**11,344**	**11,374**	9,481	9,327
Foreign Currency Translation Adjustment	*E*	**1,375**	**—**	1,262	—
Accumulated Other Comprehensive Income		**—**	**1,330**	—	1,598
		17,466	**17,481**	16,007	16,218
		$ 35,106	**$ 35,148**	$ 34,148	$ 34,102

The following table summarizes the assets and liabilities of discontinued operations included in current assets and current liabilities:

As at December 31	2006		2005	
	As Reported	**U.S GAAP**	As Reported	U.S. GAAP
Assets of Discontinued Operations	**$ —**	**$ —**	$ 1,050	$ 1,050
Liabilities of Discontinued Operations	**—**	**—**	438	438

Condensed Consolidated Statement of Cash Flows – U.S. GAAP

For the years ended December 31	2006	2005	2004
Operating Activities			
Net earnings from continuing operations	**$ 5,207**	$ 2,699	$ 2,315
Depreciation, depletion and amortization	**3,017**	2,714	2,348
Future income taxes	**1,030**	(4)	178
Unrealized (gain) loss on risk management	**(2,229)**	668	(116)
Unrealized foreign exchange (gain) loss	**76**	(50)	(285)
Accretion of asset retirement obligation	**50**	37	22
(Gain) on divestitures	**(323)**	—	(59)
Other	**166**	174	99
Cash flow from discontinued operations	**118**	464	478
Net change in other assets and liabilities	**138**	(281)	(176)
Net change in non-cash working capital from continuing operations	**3,343**	497	1,565
Net change in non-cash working capital from discontinued operations	**(2,669)**	(187)	(1,778)
Cash From Operating Activities	**$ 7,924**	$ 6,731	$ 4,591
Cash (Used in) Investing Activities	**$ (3,333)**	$ (3,942)	$ (4,259)
Cash (Used in) From Financing Activities	**$ (4,294)**	$ (3,275)	$ 163

Notes:

A) Derivative Instruments and Hedging

On January 1, 2004, the Company implemented under Canadian GAAP, EIC 128 "*Accounting For Trading, Speculative or Non-Hedging Derivative Financial Instruments*" which requires derivatives not designated as hedges to be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings. Under the transitional rules any gain or loss at the implementation date is deferred and recognized into revenue once realized. Currently, Management has not designated any of the financial instruments as hedges.

The adoption of EIC 128 at January 1, 2004 resulted in the recognition of a $235 million deferred loss which will be recognized into earnings when realized. As at December 31, 2006, under Canadian GAAP, a $16 million deferred gain remains.

For U.S. GAAP, the Company adopted Statement of Financial Accounting Standards ("SFAS") 133 effective January 1, 2001. SFAS 133 requires that all derivatives be recorded in the balance sheet as either assets or liabilities at their fair value. Changes in the derivative's fair value are recognized in current period earnings unless specific hedge accounting criteria are met. Management has currently not designated any of the financial instruments as hedges for U.S. GAAP purposes under SFAS 133.

Unrealized gain (loss) on derivatives relate to:

For the years ended December 31	**2006**	2005	2004
Commodity Prices (Revenues, net of royalties)	**$ 2,327**	$ (703)	$ 76
Interest and Currency Swaps (Interest, net)	**(11)**	(9)	(29)
Total Unrealized Gain (Loss)	**$ 2,316**	$ (712)	$ 47
Amounts Allocated to Continuing Operations	**$ 2,229**	$ (668)	$ 116
Amounts Allocated to Discontinued Operations	**87**	(44)	(69)
	$ 2,316	$ (712)	$ 47

As at December 31, 2006, it is estimated that over the following 12 months, $0.07 million ($0.05 million, net of tax) will be reclassified into net earnings from other comprehensive income.

B) Full Cost Accounting

The full cost method of accounting for crude oil and natural gas operations under Canadian GAAP and U.S. GAAP differ in the following respects. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production costs and applicable taxes. Depletion charges under U.S. GAAP are calculated by reference to proved reserves estimated using constant prices. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing to determine whether impairment exists. Any impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are calculated by reference to proved reserves estimated using estimated future prices and costs.

In computing its consolidated net earnings for U.S. GAAP purposes, the Company recorded additional depletion in 2001 and certain years prior to 2001 as a result of the application of the ceiling test. These charges were not required under the Canadian GAAP ceiling tests. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

C) Stock-Based Compensation – CPL Reorganization

Under Canadian GAAP, compensation costs have been recognized in the financial statements for stock options granted to employees and directors in 2003. For the effect of stock-based compensation on the Canadian GAAP financial statements, which would be the same adjustment under U.S. GAAP, see Note 14.

Under Financial Accounting Standards Board ("FASB") Interpretation ("FIN") No. 44 "*Accounting for Certain Transactions Involving Stock Compensation*", compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. As part of the corporate reorganization of Canadian Pacific Limited ("CPL"), an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by EnCana, as described in Note 14. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

D) Compensation Plans

Pensions and Other Post-Employment Benefits

For the year ended December 31, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 158, "*Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*". SFAS 158 requires EnCana to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through other comprehensive income. Canadian GAAP currently does not require the Company to recognize the funded status of these plans on its balance sheet.

Tandem Share Appreciation Rights and Deferred Share Units

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, the Company adopted SFAS 123(R) "*Share-Based Payment*" for the year ended December 31, 2006 using the modified-prospective approach. Under SFAS 123(R), the intrinsic-method of accounting for liability-based stock compensation plans is no longer an alternative. Liability-based stock compensation plans, including tandem share appreciation rights and deferred share units, are now required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in natural gas and crude oil exploration and development activities, such amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. As the Company adopted SFAS 123(R) using the modified prospective approach, prior periods have not been restated, as required by the standard.

SFAS 123(R), under the modified prospective approach, requires the cumulative impact of a change in an accounting policy to be presented in the current year Consolidated Statement of Earnings. The cumulative effect, net of tax, of initially adopting SFAS 123(R) January 1, 2006 was a loss of $15 million.

E) Foreign Currency Translation Adjustments

U.S. GAAP requires gains or losses arising from the translation of self-sustaining operations to be included in other comprehensive income. Canadian GAAP requires these amounts to be recorded in Shareholders' Equity.

F) Future Income Taxes

Under U.S. GAAP, enacted tax rates are used to calculate future taxes, whereas Canadian GAAP uses substantively enacted tax rates.

The future income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31	**2006**	2005	2004
Net Earnings Before Income Tax – U.S. GAAP	**$ 7,179**	$ 3,900	$ 3,052
Canadian Statutory Rate	**34.7%**	37.9%	39.1%
Expected Income Tax	**2,491**	1,478	1,193
Effect on Taxes Resulting from:			
Non-deductible Canadian Crown payments	**97**	207	192
Canadian resource allowance	**(16)**	(202)	(256)
Statutory and other rate differences	**(98)**	(235)	(50)
Effect of tax rate reductions	**(457)**	—	(109)
Non-taxable capital gains	**(1)**	(24)	(91)
Previously unrecognized capital losses	**—**	—	17
Tax basis retained on divestitures	**—**	(68)	(169)
Large corporations tax	**—**	25	24
Other	**(44)**	20	(14)
Income Tax – U.S. GAAP	**$ 1,972**	$ 1,201	$ 737
Effective Tax Rate	**27.5%**	30.7%	24.1%

The net future income tax liability is comprised of:

As at December 31	2006	2005
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**$ 4,632**	$ 4,407
Timing of partnership items	**1,251**	1,226
Other	**317**	—
Future Tax Assets		
Net operating losses carried forward	**(11)**	(47)
Other	**—**	(433)
Net Future Income Tax Liability	**$ 6,189**	$ 5,153

G) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of SFAS 133. At December 31, 2006, accumulated other comprehensive income related to these items was a loss of $2.1 million, net of tax.

H) Consolidated Statement of Cash Flows

Certain items presented as investing or financing activities under Canadian GAAP are required to be presented as operating activities under U.S. GAAP.

I) Dividends Declared on Common Stock

For the years ended December 31	2006	2005	2004
Dividends per share	**$ 0.39**	$ 0.28	$ 0.20

J) Recent Accounting Pronouncements

As of January 1, 2006, the Company adopted, for U.S. GAAP purposes, SFAS 154 "*Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and SFAS 3*". SFAS 154 requires retrospective application of voluntary changes in accounting principles, unless it is impracticable. This standard has not had a material impact on the Company's Consolidated Financial Statements.

As of January 1, 2006, the Company adopted EITF 04-13 "*Accounting for Purchases and Sales of Inventory with the Same Counterparty*". This change was adopted for Canadian and U.S. GAAP purposes. This change has no effect on the net earnings of the reported periods. Refer to Note 2 for further information.

The Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2007, EnCana will be required to adopt, for U.S. GAAP purposes, FASB Interpretation No. 48 "*Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*". This Interpretation clarifies financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Guidance is also provided on the derecognition of previously recognized tax benefits and the classification of tax liabilities on the balance sheet. The Company is assessing the impact this Interpretation will have on our Consolidated Financial Statements.
- As of January 1, 2008, EnCana will be required to adopt, for U.S. GAAP purposes, SFAS 157 "*Fair Value Measurements*". SFAS 157 provides a common definition of fair value, establishes a framework for measuring fair value under U.S. GAAP and expands disclosures about fair value measurements. This Statement applies when other accounting pronouncements require fair value measurements and does not require new fair value measurements. The Company is assessing the impact this Statement will have on our Consolidated Financial Statements.

Supplementary oil and gas information – SFAS 69 (unaudited)

For the year ended December 31, 2006 (prepared in US$)

Other Disclosures About Oil and Gas Activities

The tables in this section set forth oil and gas information prepared by EnCana in accordance with U.S. disclosure standards, including Statement of Financial Accounting Standard Number 69 ("SFAS 69").

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to EnCana's annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by EnCana's independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by EnCana to account for management's estimates of price risk management activities, asset retirement obligations and future income taxes.

EnCana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of EnCana's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to EnCana's Market Optimization interests.

Net proved reserves (unaudited)

Net Proved Reserves
(EnCana Share After Royalties) [1,2]
Constant Pricing

	Natural Gas (billions of cubic feet)				Crude Oil and Natural Gas Liquids (millions of barrels)				
	Canada	United States	United Kingdom	**Total**	Canada	United States	Ecuador	United Kingdom	**Total**
2004									
Beginning of year	5,256	3,129	26	**8,411**	629.4	41.6	161.7	124.5	**957.2**
Revisions and improved recovery	67	(252)	—	**(185)**	31.1	0.2	(11.5)	—	**19.8**
Extensions and discoveries	1,422	1,009	—	**2,431**	93.6	47.6	21.2	—	**162.4**
Purchase of reserves in place	65	1,150	10	**1,225**	29.4	11.7	—	10.1	**51.2**
Sale of reserves in place	(215)	(82)	(25)	**(322)**	(97.3)	(5.4)	—	(128.4)	**(231.1)**
Production	(771)	(318)	(11)	**(1,100)**	(56.6)	(4.7)	(28.1)	(6.2)	**(95.6)**
End of year before bitumen revisions	5,824	4,636	—	**10,460**	629.6	91.0	143.3	—	**863.9**
Revisions due to bitumen price	—	—	—	**—**	(362.7) [3]	—	—	—	**(362.7)**
End of year	5,824	4,636	—	**10,460**	266.9	91.0	143.3	—	**501.2**
Developed	4,406	2,496	—	**6,902**	210.2	31.5	122.5	—	**364.2**
Undeveloped	1,418	2,140	—	**3,558**	56.7	59.5	20.8	—	**137.0**
Total	5,824	4,636	—	**10,460**	266.9	91.0	143.3	—	**501.2**
2005									
Beginning of year	5,824	4,636	—	**10,460**	266.9	91.0	143.3	—	**501.2**
Revisions due to bitumen price	—	—	—	**—**	362.7 [4]	—	—	—	**362.7**
Beginning of year before bitumen revisions	5,824	4,636	—	**10,460**	629.6	91.0	143.3	—	**863.9**
Revisions and improved recovery	202	(260)	—	**(58)**	222.1	(3.2)	8.1	—	**227.0**
Extensions and discoveries	1,289	1,252	—	**2,541**	148.1	8.9	10.2	—	**167.2**
Purchase of reserves in place	7	76	—	**83**	—	0.4	—	—	**0.4**
Sale of reserves in place	(30)	(37)	—	**(67)**	(15.1)	(39.0)	—	—	**(54.1)**
Production	(775)	(400)	—	**(1,175)**	(52.2)	(5.0)	(26.6)	—	**(83.8)**
End of year	6,517	5,267	—	**11,784**	932.5	53.1	135.0 [5]	—	**1,120.6**
Developed	4,513	2,718	—	**7,231**	318.7	32.2	104.0	—	**454.9**
Undeveloped	2,004	2,549	—	**4,553**	613.8	20.9	31.0	—	**665.7**
Total	6,517	5,267	—	**11,784**	932.5	53.1	135.0	—	**1,120.6**
2006									
Beginning of year	6,517	5,267	—	**11,784**	932.5	53.1	135.0	—	**1,120.6**
Revisions and improved recovery	301	(88)	—	**213**	(39.0)	(1.1)	—	—	**(40.1)**
Extensions and discoveries	1,014	606	—	**1,620**	238.7	6.4	—	—	**245.1**
Purchase of reserves in place	—	68	—	**68**	—	0.3	—	—	**0.3**
Sale of reserves in place	(6)	(32)	—	**(38)**	(0.1)	—	(130.6)	—	**(130.7)**
Production	(798)	(431)	—	**(1,229)**	(52.7)	(4.7)	(4.4)	—	**(61.8)**
End of year	7,028	5,390	—	**12,418**	1,079.4 [6]	54.0	—	—	**1,133.4**
Developed	4,718	2,964	—	**7,682**	316.9	33.5	—	—	**350.4**
Undeveloped	2,310	2,426	—	**4,736**	762.5	20.5	—	—	**783.0**
Total	7,028	5,390	—	**12,418**	1,079.4 [6]	54.0	—	—	**1,133.4**

(1) Definitions:
   a. “Net” reserves are the remaining reserves of EnCana, after deduction of estimated royalties and including royalty interests.
   b. “Proved” reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.
   c. “Proved Developed” reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
   d. “Proved Undeveloped” reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) EnCana does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

(3) Removal of the Corporation’s Foster Creek proved bitumen reserves as a result of low bitumen prices on December 31, 2004.

(4) Reinstatement, as a result of year-end 2005 prices, of the Corporation’s Foster Creek proved bitumen reserves that were deducted as a revision due to bitumen price at year-end 2004.

(5) The Corporation divested of its Ecuadorian operations in 2006.

(6) Proved crude oil and NGLs reserves at December 31, 2006 include approximately 800 million barrels of bitumen, of which 796 million barrels was attributable to the Corporation’s interests in Foster Creek and Christina Lake on that date. Effective January 2, 2007, these interests were contributed to the Upstream Partnership in which the Corporation has a 50 percent interest. Accordingly, effective as at that date, the Corporation’s reserves associated with those properties were reduced by 398 million barrels.

Standardized measure of discounted future net cash flows (unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Future cash inflows	**72,262**	71,786	37,791	**27,165**	40,504	27,063	**–**	5,350	3,317
Less future:									
Production costs	**20,471**	16,765	7,760	**4,123**	3,262	2,462	**–**	2,093	1,136
Development costs	**9,355**	6,164	3,157	**4,715**	4,174	3,213	**–**	429	198
Asset retirement obligation payments	**2,397**	2,269	1,749	**396**	264	193	**–**	24	22
Income taxes	**8,816**	13,170	6,279	**5,349**	11,041	7,021	**–**	662	342
Future net cash flows	**31,223**	33,418	18,846	**12,582**	21,763	14,174	**–**	2,142	1,619
Less 10% annual discount for estimated timing of cash flows	**14,627**	13,281	6,668	**6,128**	10,291	6,686	**–**	574	417
Discounted future net cash flows	**16,596**	20,137	12,178	**6,454**	11,472	7,488	**–**	1,568	1,202

	United Kingdom			Total		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Future cash inflows	**–**	–	–	**99,427**	117,640	68,171
Less future:						
Production costs	**–**	–	–	**24,594**	22,120	11,358
Development costs	**–**	–	–	**14,070**	10,767	6,568
Asset retirement obligation payments	**–**	–	–	**2,793**	2,557	1,964
Income taxes	**–**	–	–	**14,165**	24,873	13,642
Future net cash flows	**–**	–	–	**43,805**	57,323	34,639
Less 10% annual discount for estimated timing of cash flows	**–**	–	–	**20,755**	24,146	13,771
Discounted future net cash flows	**–**	–	–	**23,050**	33,177	20,868

Changes in standardized measure of discounted future net cash flows (unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Canada			United States			Ecuador		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Balance, beginning of year	**20,137**	12,178	10,015	**11,472**	7,488	4,888	**1,568**	1,202	1,367
Changes resulting from:									
Sales of oil and gas produced during the period	**(5,970)**	(5,720)	(3,965)	**(2,373)**	(2,436)	(1,474)	**(142)**	(604)	(264)
Discoveries and extensions, net of related costs	**2,584**	4,278	3,562	**877**	3,582	2,436	**—**	159	236
Purchases of proved reserves in place	**—**	26	531	**69**	237	2,786	**—**	—	—
Sales of proved reserves in place	**(19)**	(279)	(1,579)	**(85)**	(486)	(271)	**(1,359)**	—	—
Net change in prices and production costs	**(5,797)**	11,624	2,264	**(7,636)**	4,716	143	**—**	967	(294)
Revisions to quantity estimates	**155**	1,071	546	**265**	(700)	(542)	**—**	88	(125)
Accretion of discount	**2,809**	1,629	1,349	**1,714**	1,103	725	**—**	147	176
Previously estimated development costs incurred net of change in future development costs	**(805)**	(888)	57	**(350)**	162	22	**(46)**	(148)	15
Other	**(174)**	63	32	**(381)**	(64)	(49)	**—**	8	(29)
Net change in income taxes	**3,676**	(3,845)	(634)	**2,882**	(2,130)	(1,176)	**(21)**	(251)	120
Balance, end of year	**16,596**	20,137	12,178	**6,454**	11,472	7,488	**—**	1,568	1,202

	United Kingdom			Total		
($ millions)	**2006**	2005	2004	**2006**	2005	2004
Balance, beginning of year	**—**	—	565	**33,177**	20,868	16,835
Changes resulting from:						
Sales of oil and gas produced during the period	**—**	—	(78)	**(8,485)**	(8,760)	(5,781)
Discoveries and extensions, net of related costs	**—**	—	—	**3,461**	8,019	6,234
Purchases of proved reserves in place	**—**	—	77	**69**	263	3,394
Sales of proved reserves in place	**—**	—	(899)	**(1,463)**	(765)	(2,749)
Net change in prices and production costs	**—**	—	—	**(13,433)**	17,307	2,113
Revisions to quantity estimates	**—**	—	—	**420**	459	(121)
Accretion of discount	**—**	—	82	**4,523**	2,879	2,332
Previously estimated development costs incurred net of change in future development costs	**—**	—	—	**(1,201)**	(874)	94
Other	**—**	—	—	**(555)**	7	(46)
Net change in income taxes	**—**	—	253	**6,537**	(6,226)	(1,437)
Balance, end of year	**—**	—	—	**23,050**	33,177	20,868

Results of operations and capitalized costs (unaudited)

Results of Operations	Canada			United States			Ecuador [1]		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Oil and gas revenues, net of royalties, transportation and selling costs	**7,190**	6,701	4,787	3,096	3,052	1,861	190	873	451
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**1,220**	981	822	723	616	387	48	269	187
Depreciation, depletion and amortization	**2,146**	1,961	1,752	869	712	487	84	234	263
Operating income (loss)	**3,824**	3,759	2,213	1,504	1,724	987	58	370	1
Income taxes	**1,235**	1,274	841	556	638	375	21	134	5
Results of operations	**2,589**	2,485	1,372	948	1,086	612	37	236	(4)

	United Kingdom			Other			Total		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Oil and gas revenues, net of royalties, transportation and selling costs	**—**	—	117	**2**	—	—	**10,478**	10,626	7,216
Less:									
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**—**	—	39	**11**	6	4	**2,002**	1,872	1,439
Depreciation, depletion and amortization	**—**	—	118	**10**	8	25	**3,109**	2,915	2,645
Operating income (loss)	**—**	—	(40)	**(19)**	(14)	(29)	**5,367**	5,839	3,132
Income taxes	**—**	—	(15)	**—**	—	—	**1,812**	2,046	1,206
Results of operations	**—**	—	(25)	**(19)**	(14)	(29)	**3,555**	3,793	1,926

(1) The sale of EnCana's Ecuador operations was completed in February 2006, and a loss on sale of $279 million, including indemnities, was recorded. Depreciation, depletion and amortization in 2006 and 2005 represents provisions which have been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the underlying accounting value of the related investments at February 28, 2006 and December 31, 2005.

Capitalized Costs	Canada			United States			Ecuador		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Proved oil and gas properties	**31,546**	27,074	22,455	**9,796**	7,753	7,552	**—**	1,926	1,784
Unproved oil and gas properties	**1,700**	1,998	1,855	**1,221**	870	728	**—**	18	45
Total capital cost	**33,246**	29,072	24,310	**11,017**	8,623	8,280	**—**	1,944	1,829
Accumulated DD&A	**14,261**	12,131	9,770	**2,595**	1,750	1,046	**—**	778	534
Net capitalized costs	**18,985**	16,941	14,540	**8,422**	6,873	7,234	**—**	1,166	1,295

	United Kingdom			Other			Total		
($ millions)	**2006**	2005	2004	**2006**	2005	2004	**2006**	2005	2004
Proved oil and gas properties	**—**	—	—	**—**	—	—	**41,342**	36,753	31,791
Unproved oil and gas properties	**—**	—	—	**361**	470	425	**3,282**	3,356	3,053
Total capital cost	**—**	—	—	**361**	470	425	**44,624**	40,109	34,844
Accumulated DD&A	**—**	—	—	**98**	222	247	**16,954**	14,881	11,597
Net capitalized costs	**—**	—	—	**263**	248	178	**27,670**	25,228	23,247

Costs incurred (unaudited)

Costs Incurred	Canada			United States			Ecuador		
($ millions)	2006	2005	2004	2006	2005	2004	2006	2005	2004
Acquisitions									
Unproved reserves	—	—	42	278	271	954	—	—	—
Proved reserves	47	30	204	6	141	2,051	—	—	—
Total acquisitions	47	30	246	284	412	3,005	—	—	—
Exploration costs	403	817	555	236	264	164	1	15	28
Development costs	3,611	3,333	2,669	1,826	1,724	1,103	46	164	213
Total costs incurred	4,061	4,180	3,470	2,346	2,400	4,272	47	179	241

	United Kingdom			Other			Total		
($ millions)	2006	2005	2004	2006	2005	2004	2006	2005	2004
Acquisitions									
Unproved reserves	—	—	—	—	—	—	278	271	996
Proved reserves	—	—	130	—	—	—	53	171	2,385
Total acquisitions	—	—	130	—	—	—	331	442	3,381
Exploration costs	—	—	22	75	70	79	715	1,166	848
Development costs	—	—	364	—	—	—	5,483	5,221	4,349
Total costs incurred	—	—	516	75	70	79	6,529	6,829	8,578

Supplemental financial information – financial statistics (unaudited)

Financial Statistics	2006					2005				
($ millions except per share amounts)	**Year**	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Consolidated										
Cash Flow (1)	**7,161**	1,761	1,894	1,815	1,691	7,426	2,510	1,931	1,572	1,413
Per share – Basic	**8.73**	2.22	2.34	2.19	1.99	8.55	2.94	2.26	1.80	1.58
– Diluted	**8.56**	2.18	2.30	2.15	1.96	8.35	2.88	2.20	1.76	1.55
Net Earnings (Loss)	**5,652**	663	1,358	2,157	1,474	3,426	2,366	266	839	(45)
Per share – Basic	**6.89**	0.84	1.68	2.60	1.74	3.95	2.77	0.31	0.96	(0.05)
– Diluted	**6.76**	0.82	1.65	2.55	1.70	3.85	2.71	0.30	0.94	(0.05)
Operating Earnings (2)	**3,271**	675	1,078	824	694	3,241	1,271	704	655	611
Per share – Diluted	**3.91**	0.84	1.31	0.98	0.80	3.64	1.46	0.80	0.73	0.67
Continuing Operations										
Cash Flow from Continuing Operations (3)	**7,043**	1,742	1,883	1,839	1,579	6,962	2,390	1,823	1,502	1,247
Net Earnings (Loss) from										
Continuing Operations	**5,051**	643	1,343	1,593	1,472	2,829	1,869	348	774	(162)
Per share – Basic	**6.16**	0.81	1.66	1.92	1.74	3.26	2.19	0.41	0.89	(0.18)
– Diluted	**6.04**	0.80	1.63	1.88	1.70	3.18	2.14	0.40	0.87	(0.18)
Operating Earnings –										
Continuing Operations (4)	**3,237**	672	1,064	841	660	3,048	1,229	733	611	475
Effective Tax Rates using										
Net Earnings	**27.3%**					30.8%				
Operating Earnings,										
excluding dispositions	**33.7%**					33.0%				
Canadian Statutory Rate	**34.7%**					37.9%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.882**	0.878	0.892	0.892	0.866	0.825	0.852	0.833	0.804	0.815
Period end	**0.858**	0.858	0.897	0.897	0.857	0.858	0.858	0.861	0.816	0.827
Cash Flow Information										
Cash From Operating Activities	**7,973**	1,697	1,655	2,325	2,297	7,430	3,427	1,215	881	1,918
Deduct (Add back):										
Net change in other assets and liabilities	**138**	90	21	38	(11)	(281)	(108)	(160)	(16)	2
Net change in non-cash working										
capital from continuing operations	**3,343**	39	(247)	1,508	2,044	497	1,165	(579)	(687)	614
Net change in non-cash working capital										
from discontinued operations	**(2,669)**	(193)	(13)	(1,036)	(1,427)	(212)	(140)	23	12	(111)
Cash Flow (1)	**7,161**	1,761	1,894	1,815	1,691	7,426	2,510	1,931	1,572	1,413
Cash Flow from Discontinued Operations	**118**	19	11	(24)	112	464	120	108	70	166
Cash Flow from Continuing Operations (3)	**7,043**	1,742	1,883	1,839	1,579	6,962	2,390	1,823	1,502	1,247

(1) 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.

(2) 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 from Canada and the effect of a reduction in income tax rates.

(3) Cash Flow from Continuing Operations 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, net change in non-cash working capital from discontinued operations and cash flow from discontinued operations, all of which are defined on the Consolidated Statement of Cash Flows.

(4) 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 from Canada and the effect of a reduction in income tax rates.

Supplemental financial information – financial statistics (unaudited)

Financial Statistics (continued)

Common Share Information

($ millions, except per share amounts)	2006 Year	2006 Q4	2006 Q3	2006 Q2	2006 Q1	2005 Year	2005 Q4	2005 Q3	2005 Q2	2005 Q1
Common Shares Outstanding (millions)										
Period end	**777.9**	777.9	800.1	815.8	836.2	854.9	854.9	853.8	860.2	881.7
Average – Basic	**819.9**	792.5	809.7	829.6	847.9	868.3	854.4	855.1	872.0	891.8
Average – Diluted	**836.5**	806.4	824.3	845.1	864.8	889.2	872.5	875.8	891.9	909.0
Price Range ($ per share)										
TSX – C$										
High	**62.52**	61.90	62.52	59.38	57.10	69.64	69.64	68.70	51.27	44.28
Low	**44.96**	48.28	48.35	49.51	44.96	32.55	50.04	47.72	39.05	32.55
Close	**53.66**	53.66	52.01	58.78	54.50	52.56	52.56	67.85	48.33	42.72
NYSE – US$										
High	**55.93**	53.90	55.93	53.31	50.50	59.82	59.82	58.49	41.56	36.45
Low	**39.54**	42.75	43.32	44.02	39.54	26.45	42.00	39.26	31.31	26.45
Close	**45.95**	45.95	46.69	52.64	46.73	45.16	45.16	58.31	39.59	35.21
Share Volume Traded (millions)	**1,634.2**	386.4	327.4	392.0	528.4	1,619.6	552.8	388.9	327.3	350.6
Share Value Traded										
(US$ millions weekly average)	**1,516.2**	1,447.9	1,272.9	1,484.8	1,850.5	1,289.1	2,050.1	1,400.4	878.8	852.6

Financial Metrics

	2006	2005
Net Debt-to-Capitalization	**27%**	33%
Net Debt-to-Adjusted EBITDA	**0.6x**	1.1x
Return on Capital Employed	**25%**	17%
Return on Common Equity	**34%**	23%

Net capital investment (unaudited)

Financial Statistics (continued)

Net Capital Investment

($ millions)	2006	2005
Upstream		
Canada – excluding Foster Creek/Christina Lake	$ 3,383	$ 3,757
Foster Creek/Christina Lake	632	393
Total Canada	4,015	4,150
United States	2,061	1,982
Other Countries	75	70
	6,151	6,202
Market Optimization	44	197
Corporate	74	78
Core Capital from Continuing Operations	6,269	6,477
Upstream		
Acquisitions		
Property		
Canada	47	30
United States (1)	284	418
Divestitures		
Property		
Canada	(59)	(447)
United States	(19)	(2,074)
Corporate (2)	(367)	—
Market Optimization		
Corporate (3)	(244)	—
Corporate	—	(2)
Net Acquisition and Divestiture Activity from Continuing Operations	(358)	(2,075)
Discontinued Operations		
Ecuador (4)	(1,116)	179
Midstream (5)	(1,531)	(484)
Net Capital Investment	$ 3,264	$ 4,097

(1) Acquired additional operated interest in East Texas which closed June 29, 2006.
(2) Sale of shares of EnCanBrasil Limitada closed August 16, 2006.
(3) Sale of shares of Entrega Gas Pipeline LLC closed February 23, 2006.
(4) Sale of Ecuador interests closed February 28, 2006.
(5) Sale of Phase 1 of Gas Storage interests closed May 12, 2006, followed by Phase 2 which closed November 17, 2006.

Operating statistics – sales volumes (unaudited)

Operating Statistics – After Royalties
Sales Volumes

	2006					2005				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations										
Produced Gas (MMcf/d)										
Canada										
Production	**2,185**	2,205	2,162	2,192	2,182	2,125	2,172	2,123	2,151	2,052
Inventory withdrawal	**—**	—	—	—	—	7	—	—	—	27
Canada Sales	**2,185**	2,205	2,162	2,192	2,182	2,132	2,172	2,123	2,151	2,079
United States	**1,182**	1,201	1,197	1,169	1,161	1,095	1,154	1,099	1,061	1,067
Total Produced Gas	**3,367**	3,406	3,359	3,361	3,343	3,227	3,326	3,222	3,212	3,146
Oil and Natural Gas Liquids (bbls/d)										
North America										
Light and Medium Oil	**44,360**	41,872	45,980	43,727	45,889	47,328	45,792	43,313	50,020	50,280
Heavy Oil										
Foster Creek/Christina Lake	**42,768**	46,678	43,073	39,215	42,050	34,379	39,839	32,580	31,025	34,027
Other	**43,369**	39,498	37,605	46,128	50,431	48,711	48,547	48,509	51,249	46,519
Natural Gas Liquids (1)										
Canada	**11,713**	11,856	11,387	11,607	12,006	11,907	12,287	11,924	11,719	11,692
United States	**12,494**	12,250	12,520	12,793	12,415	13,675	12,824	14,131	13,095	14,666
Total Oil and Natural Gas Liquids	**154,704**	152,154	150,565	153,470	162,791	156,000	159,289	150,457	157,108	157,184
Total Continuing Operations (MMcfe/d)	**4,295**	4,319	4,262	4,282	4,320	4,163	4,282	4,125	4,155	4,089
Discontinued Operations										
Ecuador										
Production	**11,996**	—	—	—	48,650	72,916	70,480	71,896	73,662	75,695
Over/(under) lifting	**370**	—	—	—	1,500	(1,851)	(537)	(3,186)	(486)	(3,208)
Ecuador Sales (bbls/d)	**12,366**	—	—	—	50,150	71,065	69,943	68,710	73,176	72,487
Total Discontinued Operations (MMcfe/d)	**74**	—	—	—	301	426	419	412	439	435
Total (MMcfe/d)	**4,369**	4,319	4,262	4,282	4,621	4,589	4,701	4,537	4,594	4,524

(1) Natural gas liquids include condensate volumes.

Operating statistics – netbacks, royalty rates (unaudited)

Operating Statistics – After Royalties (continued)
Per-unit Results

(excluding impact of realized financial hedging)	2006					2005				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations										
Produced Gas – Canada ($/Mcf)										
Price	**6.20**	5.87	5.59	5.71	7.66	7.27	10.00	7.18	6.08	5.70
Production and mineral taxes	**0.10**	0.05	0.09	0.08	0.18	0.10	0.10	0.10	0.10	0.09
Transportation and selling	**0.35**	0.33	0.37	0.35	0.34	0.36	0.36	0.36	0.36	0.37
Operating	**0.79**	0.82	0.78	0.77	0.79	0.67	0.72	0.68	0.62	0.65
Netback	**4.96**	4.67	4.35	4.51	6.35	6.14	8.82	6.04	5.00	4.59
Produced Gas – United States ($/Mcf)										
Price	**6.35**	5.65	6.04	6.08	7.70	7.82	10.84	7.51	6.60	6.04
Production and mineral taxes	**0.49**	0.50	0.43	0.22	0.85	0.81	1.19	0.75	0.65	0.62
Transportation and selling	**0.54**	0.60	0.57	0.50	0.49	0.46	0.45	0.49	0.42	0.46
Operating	**0.65**	0.68	0.59	0.70	0.64	0.53	0.60	0.55	0.50	0.45
Netback	**4.67**	3.87	4.45	4.66	5.72	6.02	8.60	5.72	5.03	4.51
Produced Gas – Total North America ($/Mcf)										
Price	**6.25**	5.79	5.75	5.84	7.68	7.46	10.29	7.29	6.25	5.81
Production and mineral taxes	**0.24**	0.21	0.21	0.13	0.41	0.34	0.48	0.32	0.28	0.27
Transportation and selling	**0.42**	0.42	0.44	0.40	0.40	0.40	0.39	0.41	0.38	0.40
Operating	**0.74**	0.77	0.71	0.74	0.74	0.62	0.68	0.64	0.58	0.58
Netback	**4.85**	4.39	4.39	4.57	6.13	6.10	8.74	5.92	5.01	4.56
Natural Gas Liquids – Canada ($/bbl)										
Price	**51.12**	44.79	55.95	55.19	48.84	44.24	49.51	47.39	39.55	40.04
Production and mineral taxes	**—**	—	—	—	—	—	—	—	—	—
Transportation and selling	**0.67**	0.58	0.74	0.73	0.61	0.42	0.46	0.48	0.39	0.35
Netback	**50.45**	44.21	55.21	54.46	48.23	43.82	49.05	46.91	39.16	39.69
Natural Gas Liquids – United States ($/bbl)										
Price	**56.33**	51.04	61.76	58.25	54.07	48.36	54.14	53.92	44.79	40.93
Production and mineral taxes	**4.19**	4.62	4.42	2.60	5.18	4.86	5.42	5.46	4.37	4.20
Transportation and selling	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Netback	**52.13**	46.41	57.33	55.64	48.88	43.49	48.71	48.45	40.41	36.72
Natural Gas Liquids – Total North America ($/bbl)										
Price	**53.81**	47.97	58.99	56.80	51.50	46.44	51.87	50.93	42.32	40.53
Production and mineral taxes	**2.16**	2.35	2.31	1.36	2.63	2.60	2.77	2.96	2.31	2.34
Transportation and selling	**0.33**	0.29	0.36	0.35	0.31	0.20	0.23	0.23	0.19	0.16
Netback	**51.32**	45.33	56.32	55.09	48.56	43.64	48.87	47.74	39.82	38.03
Crude Oil – Light and Medium – North America ($/bbl)										
Price	**51.76**	43.28	56.50	61.62	45.31	45.09	46.27	55.41	41.44	38.57
Production and mineral taxes	**2.16**	2.15	2.13	2.47	1.92	1.54	1.83	1.29	1.71	1.32
Transportation and selling	**0.98**	0.61	1.32	0.65	1.29	1.20	1.14	1.29	1.20	1.19
Operating	**8.62**	9.01	10.00	7.36	8.06	6.34	6.41	6.24	6.34	6.38
Netback	**40.00**	31.51	43.05	51.14	34.04	36.01	36.89	46.59	32.19	29.68

Operating statistics – netbacks, royalty rates (unaudited)

Operating Statistics – After Royalties (continued)
Per-unit Results

(excluding impact of realized financial hedging)	2006					2005				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Continuing Operations (continued)										
Crude Oil – Heavy										
– Foster Creek/Christina Lake ($/bbl)										
Price	**36.49**	39.32	37.19	46.53	23.08	22.02	20.17	33.11	19.28	15.92
Production and mineral taxes	**—**	—	—	—	—	—	—	—	—	—
Transportation and selling	**2.64**	2.74	2.64	3.38	1.80	1.54	1.53	1.24	2.02	1.42
Operating (1)	**12.38**	13.07	14.06	11.78	10.39	10.94	11.93	10.74	11.71	9.25
Netback	**21.47**	23.51	20.49	31.37	10.89	9.54	6.71	21.13	5.55	5.25
Crude Oil – Total Heavy										
– North America ($/bbl)										
Price	**36.72**	33.87	44.32	46.49	23.53	27.92	28.27	39.69	22.77	20.76
Production and mineral taxes	**0.05**	0.05	0.05	0.07	0.04	0.04	0.05	0.04	0.02	0.03
Transportation and selling	**1.62**	1.35	1.98	2.00	1.21	1.20	1.11	1.08	1.13	1.52
Operating	**9.33**	10.58	10.32	8.82	7.69	7.74	8.50	7.95	7.43	6.97
Netback	**25.72**	21.89	31.97	35.60	14.59	18.94	18.61	30.62	14.19	12.24
Crude Oil – Total North America ($/bbl)										
Price	**41.83**	36.94	48.74	51.62	30.76	34.15	34.41	45.16	29.83	27.60
Production and mineral taxes	**0.77**	0.74	0.81	0.88	0.66	0.58	0.66	0.48	0.66	0.53
Transportation and selling	**1.40**	1.11	1.74	1.54	1.24	1.20	1.12	1.15	1.15	1.39
Operating	**9.09**	10.05	10.20	8.34	7.82	7.23	7.79	7.35	7.02	6.74
Netback	**30.57**	25.04	35.99	40.86	21.04	25.14	24.84	36.18	21.00	18.94
Total Liquids – Canada ($/bbl)										
Price	**42.53**	37.55	49.21	51.91	32.17	34.97	35.65	45.35	30.58	28.60
Production and mineral taxes	**0.70**	0.67	0.73	0.80	0.61	0.53	0.60	0.43	0.61	0.48
Transportation and selling	**1.35**	1.06	1.67	1.48	1.19	1.14	1.07	1.09	1.09	1.31
Operating	**8.33**	9.21	9.39	7.63	7.17	6.61	7.13	6.66	6.45	6.19
Netback	**32.15**	26.61	37.42	42.00	23.20	26.69	26.85	37.17	22.43	20.62
Total Liquids – Total North America ($/bbl)										
Price	**43.71**	38.69	50.37	52.44	33.87	36.17	37.16	46.16	31.80	29.77
Production and mineral taxes	**0.99**	0.99	1.05	0.96	0.96	0.91	0.99	0.91	0.92	0.83
Transportation and selling	**1.24**	0.98	1.52	1.35	1.10	1.04	0.98	0.99	1.00	1.18
Operating	**7.66**	8.47	8.58	7.01	6.64	6.04	6.56	6.08	5.91	5.61
Netback	**33.82**	28.25	39.22	43.12	25.17	28.18	28.63	38.18	23.97	22.15
Total North America ($/Mcfe)										
Price	**6.48**	5.93	6.31	6.46	7.22	7.13	9.37	7.38	6.03	5.62
Production and mineral taxes	**0.22**	0.20	0.20	0.13	0.36	0.30	0.41	0.29	0.25	0.24
Transportation and selling	**0.37**	0.37	0.40	0.36	0.35	0.35	0.34	0.35	0.33	0.36
Operating (2)	**0.86**	0.90	0.87	0.84	0.82	0.71	0.77	0.72	0.67	0.66
Netback	**5.03**	4.46	4.84	5.13	5.69	5.77	7.85	6.02	4.78	4.36

(1) Heavy oil operating costs now include costs related to the Foster Creek power cogeneration facility.

(2) Year-to-date operating costs include costs related to long-term incentives of $0.02/Mcfe (2005 – $0.03/Mcfe).

Operating statistics – netbacks, royalty rates (unaudited)

Operating Statistics – After Royalties (continued)
Per-unit Results

	2006					2005				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Impact of Upstream Realized Financial Hedging										
Natural Gas ($/Mcf)	**0.47**	0.91	0.82	0.66	(0.53)	(0.32)	(0.88)	(0.39)	(0.14)	0.18
Liquids ($/bbl)	**(3.32)**	(3.30)	(3.45)	(3.43)	(3.12)	(5.18)	(5.00)	(5.70)	(4.88)	(5.18)
Total ($/Mcfe)	**0.25**	0.60	0.53	0.40	(0.53)	(0.44)	(0.87)	(0.52)	(0.30)	(0.06)
Average Royalty Rates (excluding impact of realized financial hedging)										
Produced Gas										
Canada	**10.5%**	9.9%	10.5%	10.4%	11.2%	11.7%	11.9%	11.8%	11.0%	11.9%
United States	**18.5%**	18.3%	18.4%	18.7%	18.7%	18.6%	18.6%	19.9%	17.9%	18.1%
Crude Oil										
Canada and United States	**9.9%**	10.3%	11.4%	10.5%	7.5%	8.8%	8.8%	8.7%	9.2%	8.7%
Natural Gas Liquids										
Canada	**15.5%**	15.3%	16.3%	14.4%	16.1%	14.9%	14.4%	15.8%	15.6%	13.8%
United States	**18.7%**	18.8%	17.7%	20.1%	18.3%	18.2%	19.4%	20.1%	12.7%	20.0%
Total North America	**13.0%**	12.7%	13.2%	13.1%	12.9%	13.3%	13.5%	13.8%	12.6%	13.3%
Discontinued Operations (excluding impact of realized financial hedging)										
Crude Oil – Ecuador ($/bbl)										
Price	**44.35**	—	—	—	44.35	39.36	37.82	47.76	36.37	35.80
Production and mineral taxes	**5.03**	—	—	—	5.03	5.04	4.63	7.66	4.53	3.42
Transportation and selling	**2.25**	—	—	—	2.25	2.25	1.86	2.45	2.48	2.21
Operating	**5.55**	—	—	—	5.55	5.32	5.82	6.05	5.18	4.26
Netback	**31.52**	—	—	—	31.52	26.75	25.51	31.60	24.18	25.91
Impact of Upstream Realized Financial Hedging – Crude Oil										
Ecuador ($/bbl)	**(0.12)**	—	—	—	(0.12)	(4.92)	(3.57)	(7.81)	(4.90)	(3.48)
Average Royalty Rates (excluding impact of realized financial hedging)										
Crude Oil										
Ecuador	**25.2%**	—	—	—	25.2%	27.2%	29.4%	26.3%	26.3%	26.9%

Drilling activity

The following tables summarize EnCana's gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations											
2006											
Canada	**281**	**230**	**7**	**7**	**7**	**6**	**295**	**243**	**128**	**423**	**243**
United States	**12**	**7**	**—**	**—**	**2**	**1**	**14**	**8**	**—**	**14**	**8**
Other	**—**	**—**	**2**	**1**	**4**	**1**	**6**	**2**	**—**	**6**	**2**
Total	**293**	**237**	**9**	**8**	**13**	**8**	**315**	**253**	**128**	**443**	**253**
2005											
Canada	605	540	8	8	7	7	620	555	99	719	555
United States	7	6	—	—	9	7	16	13	1	17	13
Other	—	—	3	1	3	2	6	3	—	6	3
Total	612	546	11	9	19	16	642	571	100	742	571
2004											
Canada	566	534	48	47	9	6	623	587	51	674	587
United States	19	16	2	—	—	—	21	16	—	21	16
Other	—	—	3	2	5	2	8	4	—	8	4
Total	585	550	53	49	14	8	652	607	51	703	607
Discontinued Operations											
Ecuador – 2006	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Ecuador – 2005	—	—	2	1	3	2	5	3	—	5	3
Ecuador – 2004	—	—	6	3	—	—	6	3	—	6	3
United Kingdom – 2004	—	—	1	—	4	2	5	2	—	5	2

Drilling activity

Development Wells Drilled

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
Continuing Operations 2006											
Canada	**2,799**	**2,639**	**139**	**103**	**25**	**24**	**2,963**	**2,766**	**855**	**3,818**	**2,766**
United States	**779**	**625**	**—**	**—**	**7**	**6**	**786**	**631**	**22**	**808**	**631**
Total	**3,578**	**3,264**	**139**	**103**	**32**	**30**	**3,749**	**3,397**	**877**	**4,626**	**3,397**
2005											
Canada	3,503	3,229	277	243	12	11	3,792	3,483	932	4,724	3,483
United States	699	604	—	—	—	—	699	604	9	708	604
Total	4,202	3,833	277	243	12	11	4,491	4,087	941	5,432	4,087
2004											
Canada	3,632	3,419	386	364	16	15	4,034	3,798	1,105	5,139	3,798
United States	600	515	1	—	3	3	604	518	—	604	518
Total	4,232	3,934	387	364	19	18	4,638	4,316	1,105	5,743	4,316
Discontinued Operations											
Ecuador – 2006	**—**	**—**	**7**	**6**	**1**	**1**	**8**	**7**	**—**	**8**	**7**
Ecuador – 2005	—	—	28	15	3	1	31	16	—	31	16
Ecuador – 2004	—	—	43	25	1	1	44	26	—	44	26
United Kingdom – 2004	—	—	3	1	—	—	3	1	—	3	1

(1) "Gross" wells are the total number of wells in which EnCana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating EnCana's working interest in each of its gross wells.

(3) At December 31, 2006, EnCana was in the process of drilling 34 gross wells (32 net wells) in Canada, 46 gross wells (34 net wells) in the United States and one well outside of North America.

Land

Interest in Material Properties

The following table summarizes EnCana's developed, undeveloped and total land holdings as at December 31, 2006:

	Developed		Undeveloped		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Continuing Operations						
Canada						
Alberta						
Fee	4,415	4,415	2,708	2,707	**7,123**	**7,122**
Crown	4,051	3,200	5,259	4,368	**9,310**	**7,568**
Freehold	230	132	212	175	**442**	**307**
	8,696	7,747	8,179	7,250	**16,875**	**14,997**
British Columbia						
Crown	1,053	900	4,353	3,653	**5,406**	**4,553**
Freehold	—	—	7	—	**7**	**—**
	1,053	900	4,360	3,653	**5,413**	**4,553**
Saskatchewan						
Fee	62	62	457	457	**519**	**519**
Crown	133	114	508	461	**641**	**575**
Freehold	15	11	51	48	**66**	**59**
	210	187	1,016	966	**1,226**	**1,153**
Manitoba						
Fee	3	3	263	263	**266**	**266**
	3	3	263	263	**266**	**266**
Newfoundland & Labrador						
Crown	—	—	1,550	1,018	**1,550**	**1,018**
Nova Scotia						
Crown	—	—	1,184	638	**1,184**	**638**
Northwest Territories						
Crown	—	—	314	174	**314**	**174**
Yukon						
Crown	—	—	5	2	**5**	**2**
Beaufort						
Crown	—	—	125	4	**125**	**4**
Total Canada	9,962	8,837	16,996	13,968	**26,958**	**22,805**

Land

Interest in Material Properties (continued)

	Developed		Undeveloped		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States						
Colorado						
Federal/State Lands	191	178	798	732	**989**	**910**
Freehold	110	104	161	147	**271**	**251**
Fee	3	3	37	37	**40**	**40**
	304	285	996	916	**1,300**	**1,201**
Washington						
Federal/State Lands	—	—	638	626	**638**	**626**
Freehold	—	—	185	185	**185**	**185**
	—	—	823	811	**823**	**811**
Texas						
Federal/State Lands	8	3	441	423	**449**	**426**
Freehold	172	113	1,216	988	**1,388**	**1,101**
Fee	—	—	4	2	**4**	**2**
	180	116	1,661	1,413	**1,841**	**1,529**
Wyoming						
Federal/State Lands	143	87	785	593	**928**	**680**
Freehold	25	18	57	35	**82**	**53**
	168	105	842	628	**1,010**	**733**
Other						
Federal/State Lands	9	7	336	199	**345**	**206**
Freehold	12	5	1,031	1,026	**1,043**	**1,031**
	21	12	1,367	1,225	**1,388**	**1,237**
Total United States	673	518	5,689	4,993	**6,362**	**5,511**
International						
Chad	—	—	54,103	27,052	**54,103**	**27,052**
Oman	—	—	8,568	4,284	**8,568**	**4,284**
Qatar	—	—	2,160	1,081	**2,160**	**1,081**
Greenland	—	—	1,701	1,488	**1,701**	**1,488**
Brazil	—	—	1,662	522	**1,662**	**522**
Australia	—	—	1,053	357	**1,053**	**357**
France	—	—	859	859	**859**	**859**
Azerbaijan	—	—	346	17	**346**	**17**
Total International	—	—	70,452	35,660	**70,452**	**35,660**
Total	10,635	9,355	93,137	54,621	**103,772**	**63,976**

(1) This table excludes approximately 4.2 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those lands in which EnCana has a fee simple interest in the minerals rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands acreage summary now includes all fee titles owned by EnCana that have one or more zones that remain unleased or available for development.

(3) Crown/Federal/State lands are those owned by the federal, provincial, or state government or the First Nations, in which EnCana has purchased a working interest lease.

(4) Freehold lands are owned by individuals (other than a Government or EnCana), in which EnCana holds a working interest lease.

(5) Gross acres are the total area of properties in which EnCana has an interest.

(6) Net acres are the sum of EnCana's fractional interest in gross acres.

(7) In January 2007, a subsidiary of EnCana completed the sale of all its interests in its Chad exploration assets.

Corporate information

Corporate Officers [1]

David P. O'Brien
Chairman of the Board

Randall K. Eresman
President & Chief Executive Officer

John K. Brannan
Executive Vice-President
(*President, Integrated Oilsands Division)*

Sherri A. Brillon
Executive Vice-President, Strategic Planning & Portfolio Management

Brian C. Ferguson
Executive Vice-President
& Chief Financial Officer

Kerry D. Dyte
Vice-President, General Counsel
& Corporate Secretary

Thomas G. Hinton
Treasurer
(Vice-President, Corporate Finance Group)

William A. Stevenson
Comptroller
(Vice-President, Corporate Finance Group)

Michael M. Graham
Executive Vice-President
(*President, Canadian Foothills Division)*

Sheila M. McIntosh
Executive Vice-President,
Corporate Communications

R. William Oliver
Executive Vice-President,
Business Development
(*President, Midstream & Marketing Division)*

Gerard J. Protti
Executive Vice-President,
Corporate Relations
(*President, Offshore & International Division)*

Donald T. Swystun
Executive Vice-President
(*President, Canadian Plains Division)*

Hayward J. Walls
Executive Vice-President,
Corporate Services

Jeff E. Wojahn
Executive Vice-President
(*President, USA Division)*

(1) Divisional title in italics.

Board of Directors

Michael N. Chernoff (2)(6)
West Vancouver, British Columbia

Ralph S. Cunningham (2)(3)
Houston, Texas

Patrick D. Daniel (1)(5)
Calgary, Alberta

Ian W. Delaney (3)(4)
Toronto, Ontario

Randall K. Eresman
Calgary, Alberta

Michael A. Grandin (3)(4)(6)
Calgary, Alberta

Barry W. Harrison (1)(4)
Calgary, Alberta

Dale A. Lucas (1)(5)
Calgary, Alberta

Ken F. McCready (2)(5)
Calgary, Alberta

Valerie A. A. Nielsen (2)(6)
Calgary, Alberta

David P. O'Brien (4)(7)
Calgary, Alberta

Jane L. Peverett (1)(5)
West Vancouver, British Columbia

Dennis A. Sharp (2)(4)
Calgary, Alberta & Montreal, Quebec

James M. Stanford, O.C. (1)(3)(6)
Calgary, Alberta

(1) Audit Committee
(2) Corporate Responsibility, Environment, Health and Safety Committee
(3) Human Resources and Compensation Committee
(4) Nominating and Corporate Governance Committee
(5) Pension Committee
(6) Reserves Committee
(7) Chairman of the Board, Chairman of Nominating and Corporate Governance Committee, and ex officio member of all other Board Committees

EnCana Head Office

1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-2000
www.encana.com

Corporate information

Transfer Agents & Registrar

Common Shares

CIBC Mellon Trust Company

Calgary, Montreal and Toronto

Mellon Investor Services LLC

New York

Shareholders are encouraged to contact CIBC Mellon Trust Company for information regarding their security holdings. They can be reached via the Answerline 416-643-5500 or toll-free throughout North America at 1-800-387-0825, or via facsimile at 416-643-5501.

Mailing Address

CIBC Mellon Trust Company

P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9

Internet Address

www.cibcmellon.com

Trustee & Registrars

CIBC Mellon Trust Company

Canadian Medium Term Notes
Calgary, Alberta
Toronto, Ontario

The Bank of New York

4.600% Senior Notes
4.750% Senior Notes
6.500% Senior Notes
7.375% Senior Notes
7.650% Senior Notes
8.125% Senior Notes
New York, New York

The Bank of Nova Scotia
Trust Company of New York

6.30% Senior Notes
7.20% Senior Notes
New York, New York

Deutsche Bank Trust Company Americas

5.80% Senior Notes
(EnCana Holdings Finance Corp.)
New York, New York

Auditors

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

Independent Qualified Reserve Evaluators

DeGolyer and MacNaughton
Dallas, Texas

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Stock Exchanges

Common Shares (ECA)

Toronto Stock Exchange
New York Stock Exchange

Principal Operating Subsidiaries & Partnerships

	Percent Owned (1)
EnCana Marketing (USA) Inc.	100
EnCana Oil & Gas (USA) Inc.	100
EnCana Oil & Gas Partnership	100
FCCL Oil Sands Partnership	50
WRB Refining LLC	50

(1) Includes indirect ownership.

The above is not a complete list of all of the subsidiaries and partnerships of EnCana Corporation.

Investor information

Annual Meeting

Shareholders are invited to attend the Annual Meeting being held on Wednesday, April 25, 2007 at 2:00 p.m. local time at the TELUS Convention Centre Exhibition Hall E 2nd Floor, North Building 136 – 8th Avenue S.E. Calgary, Alberta.

Those unable to do so are asked to sign and return the form of proxy that has been mailed to them.

Annual Information Form (Form 40-F)

EnCana's Annual Information Form (AIF) is filed with the securities regulators in Canada and the United States. Under the Multi-Jurisdictional Disclosure System, EnCana's AIF is filed as Form 40-F with the U.S. Securities and Exchange Commission.

Shareholder Account Matters

To change your address, transfer shares, eliminate duplicate mailings, have dividends deposited directly into accounts at financial institutions in Canada that provide electronic fund-transfer services, etc., please contact CIBC Mellon Trust Company.

EnCana Website
www.encana.com

EnCana's website contains a variety of corporate and investor information including, among other information, the following:

- Current stock prices
- Annual and Interim Reports
- Information Circular
- News releases
- Investor presentations
- Dividend information
- Shareholder support information

Additional information, including copies of the 2006 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations,
Corporate Communications
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: 403-645-3550
www.encana.com

Investor inquiries should be directed to:

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paul.gagne@encana.com

Susan Grey
Manager, Investor Relations
403-645-4751
susan.grey@encana.com

Ryder McRitchie
Manager, Investor Relations
403-645-2007
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Media inquiries should be directed to:

Alan Boras
Manager, Media Relations
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alan.boras@encana.com

Abbreviations

API	American Petroleum Institute – measure of oil specific gravity
bbls	barrels
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrel of oil equivalent
Btu	British thermal unit
km	kilometre(s)
m	metre(s)
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MM	million
MMbbls	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfe	million cubic feet equivalent
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
PCI	product carbon intensity
SAGD	steam-assisted gravity drainage
Tcf	trillion cubic feet
Tcfe	trillion cubic feet equivalent
WTI	West Texas Intermediate