February 15, 2006

EnCana generates 2005 cash flow of US$7.4 billion, or $8.35 per share – up 57 percent; Net earnings reach $3.43 billion

EnCana proved reserves additions replace 271% of production Proved reserves increase 18 percent with addition of 4.5 trillion cubic feet of gas equivalent

CALGARY, Feb. 15 /CNW/ - EnCana Corporation (TSX & NYSE: ECA) today reports a 57 percent increase in 2005 cash flow per share to US$8.35 per share diluted, or $7.4 billion, compared to 2004. Total operating earnings per share in 2005 increased 73 percent to $3.64 per share diluted, or $3.24 billion. Net earnings per share increased 3 percent to $3.85 per share diluted, or $3.43 billion.

EnCana replaced 271 percent of its 2005 production and increased total proved reserves by 18 percent to 18.5 trillion cubic feet of gas equivalent (Tcfe) by adding 4.5 Tcfe, compared to production of 1.7 Tcfe.

"EnCana achieved record natural gas production, strong financial results, solid operating performance and tremendous proved reserves additions in a year characterized by robust prices and tough operating conditions," said Randy Eresman, EnCana's President & Chief Executive Officer. "Our 2005 natural gas sales were up 8 percent, while our key resource plays achieved 18 percent year-over-year production growth."

Three-year reserves replacement cost averages $1.22 per thousand cubic feet equivalent

"The difficult operating conditions that existed during most of 2005 continued through year-end. Despite these challenges, we continued to achieve significant long-term value creation. Over the past three years, we have sharpened our focus on North American unconventional resources through increased investment in land and drilling, and by high-grading our portfolio of assets through acquisitions and divestitures. With all the portfolio changes we've undertaken, we believe the best indicator of our value creation is our reserve replacement cost, which accounts for all of the reserves we bought, sold and found with the drill bit, and best reflects the value creation of our option value exploration program. In the past three years that reserve replacement cost averaged a very attractive $1.22 per thousand cubic feet equivalent. In 2005, we also had extremely strong reserves additions with the drill bit alone, which averaged a finding and development cost of $1.29 per thousand cubic feet equivalent. Excluding bitumen additions, our 2005 finding and development costs averaged $1.93 per thousand cubic feet equivalent. With our solid sales growth and double-digit reserves growth in 2005, EnCana is continuing to build momentum in the growth rate of net asset value in every share by strengthening its unconventional resource base," Eresman said.

IMPORTANT NOTE: EnCana reports in U.S. dollars unless otherwise noted and follows U.S. protocols, which report sales and reserves on an after-royalties basis. All prior-period share and per-share references have been adjusted to reflect the two-for-one common share split which occurred in May 2005. EnCana's natural gas liquids business was sold and is discontinued. The company is reporting its Ecuador operations and its natural gas storage business as discontinued because EnCana is in the process of selling them. Total results, which include results from natural gas liquids, Ecuador and natural gas storage, are reported in the company's financial statements included in this news release and in supplementary documents posted on its website - www.encana.com. The company's financial statements are prepared in accordance with Canadian generally accepted accounting principles (GAAP).

2005 Highlights

Financial
- Cash flow per share diluted increased 57 percent to $8.35
- Operating earnings per share diluted up 73 percent to $3.64
- Net earnings per share diluted up 3 percent to $3.85
- Generated $2.7 billion in free cash flow (as defined in Note 1 on page 11)
- Return on capital employed of 17 percent
- Purchased 55.2 million EnCana shares at an average share price of $34.85 under the Normal Course Issuer Bid
- Reduced shares outstanding by 4.5 percent

Operating
- Natural gas sales of 3.23 billion cubic feet per day (Bcf/d), up 8 percent
- Oil and natural gas liquids (NGLs) sales of 227,100 barrels per day (bbls/d), down 13 percent
- Key resource play production up 18 percent; oilsands production exceeded 50,000 bbls/d in December 2005
- Operating costs of 68 cents per thousand cubic feet equivalent (Mcfe)
- Upstream capital investment in continuing operations of $6.2 billion
- Net divestitures of $2.1 billion in non-core upstream assets, resulting in net upstream capital investment of $4.1 billion

Reserves
- Drill bit additions and revisions of 4.8 Tcfe of proved reserves, including 1.9 Tcfe of bitumen
- Proved reserves increased 18 percent to 18.5 Tcfe
- Reinstated 363 million barrels of bitumen to proved reserves
- Finding and development (F&D) costs averaged $1.29 per Mcfe, excluding bitumen reinstatement
- Production replacement of 271 percent, excluding bitumen reinstatement
- Average three-year reserve replacement cost of $1.22 per Mcfe

Strategic events
- Sold Gulf of Mexico assets for $2.1 billion
- Sold natural gas liquids business for $625 million
- Agreements reached to sell Ecuador assets for $1.42 billion and Brazil oil discovery for $350 million
- Announced plans to expand in-situ oilsands production to more than 500,000 barrels per day by 2015

2006 objectives
- Grow sales from continuing operations between 4 and 9 percent, natural gas sales between 6 and 10 percent
- Complete downstream initiative in support of high-growth in-situ oilsands production to more than 500,000 barrels per day by 2015
- Complete sales of Ecuador and Brazil assets
- Complete the sale of natural gas storage business

2006 capital forecast trimmed $800 million; gas sales forecast reduced by 75 million cubic feet per day

Looking to 2006, the North American oil and gas industry continues to run at a fevered pace. The inflationary pressures of 2005 are expected to continue this year with cost inflation once again above 15 percent. Given these circumstances, EnCana has decided to reduce drilling in areas where costs have increased the most, resulting in a $500 million reduction in its previously-announced 2006 upstream capital investment forecast. In addition, EnCana's 2005 gas sales exit rate was lower than planned due to fewer wells drilled by year-end. The combined impact on 2006 gas sales is a reduction of about 75 million cubic feet per day from EnCana's previous forecast. The changes are reflected in EnCana's updated corporate guidance. The $500 million upstream capital reduction includes $200 million invested in late 2005 for acceleration of drilling coalbed methane wells and expansion of in-situ oilsands programs, and in 2006, $100 million for exploration and $200 million for development programs. A further $300 million of capital previously assigned to building the second segment of the Entrega Pipeline is not expected to be required as EnCana has entered into an agreement to sell Entrega, which is expected to close in the first quarter of 2006. In total, the company is reducing its 2006 capital investment plans by about $800 million, or 12 percent.

EnCana's 2006 natural gas sales expected to increase by about 8 percent
With fewer wells planned this year, EnCana's 2006 natural gas sales are expected to increase 8 percent, at the midpoint of revised guidance - a growth rate similar to what was achieved in 2005. EnCana's North American oil and NGLs sales forecast is unchanged and remains about the same as 2005, with additional volumes expected to come on stream near year-end from an expansion of steam-assisted gravity drainage (SAGD) production at Foster Creek.

More than 90 percent of 2006 gas sales has floor price protection
To help assure strong financial performance, EnCana put in place, during the fourth quarter of 2005, put options on about 1.6 billion cubic feet per day of 2006 planned gas sales at an average strike price of NYMEX $8.42 per thousand cubic feet. All in, about 93 percent of EnCana’s forecast 2006 gas sales is hedged with a combination of put options and fixed price hedges with an average price of NYMEX $7.30 per thousand cubic feet.

Net capital investment in 2006 forecast at $2.8 billion
EnCana has a series of non-core asset divestitures well underway that are expected to generate between $3 billion and $3.4 billion this year, with proceeds designated to share purchases and debt reduction. With a capital investment forecast between $5.8 billion and $6.2 billion, the company expects its 2006 net capital investment to be about $2.8 billion.

Corporate guidance updated
EnCana has updated its 2006 corporate guidance on its website: www.encana.com. In addition to reflecting the most recent sales and capital outlooks, the guidance indicates a reduction in cash tax expense, expressed as percentage of pre-tax cash flow from continuing operations.

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Financial Summary - Total Consolidated

(for the period ended December 31) ($ millions, except per share amounts)	Q4 2005	Q4 2004	% change	2005	2004	% change
Cash flow	2,510	1,491	+ 68	7,426	4,980	+ 49
Per share diluted	2.88	1.60	+ 80	8.35	5.32	+ 57
Net earnings	2,366	2,580	- 8	3,426	3,513	- 2
Per share diluted	2.71	2.77	- 2	3.85	3.75	+ 3
Operating earnings(1)	1,271	573	+ 122	3,241	1,976	+ 64
Per share diluted	1.46	0.62	+ 135	3.64	2.11	+ 73

Earnings Reconciliation Summary - Total Consolidated

Net earnings from continuing operations	1,869	1,055	+ 77	2,829	2,093	+ 35
Net earnings from discontinued operations	497	1,525	- 67	597	1,420	- 58

Net Earnings 2,366 2,580 - 8 3,426 3,513 - 2
(Add back losses &
deduct gains)
Unrealized mark-to-
market hedging gain
(loss), after-tax 746 512 (277) (165)

Unrealized foreign
exchange gain (loss)
on translation of
U.S. dollar debt
issued in Canada,
after-tax (21) 131 92 229

Tax rate change - - - 109

Gain on divestitures
after-tax (2)370 (3)1,364 (2)370 (3)1,364

Operating earnings 1,271 573 + 122 3,241 1,976 + 64
Per share 1.46 0.62 + 135 3.64 2.11 + 73

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(1) Total operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain on the sale of discontinued operations, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.
(2) Gain on sale of natural gas liquids business
(3) Gain on sale of U.K. North Sea assets

Net earnings note:
The 2005 financial results include a one-time interest charge in the third quarter of $79 million after-tax for the retirement of debt instruments with an interest rate higher than current rates. Also, on September 13, 2005, EnCana announced it had reached an agreement to sell all of its interest in its Ecuador operations for approximately $1.42 billion, which is approximately equivalent to the asset's net book value at July 1, 2005, the referenced effective date of the transaction. All economic benefits occurring after the July 1, 2005 effective date accrue to the purchaser. Included in net earnings for 2005 is a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments, as required under Canadian generally accepted accounting principles.

Sales & Drilling Summary

Total Consolidated

(for the period
ended December 31) Q4 Q4 % %
(After royalties) 2005 2004 change 2005 2004 change

Natural Gas sales
(MMcf/d) 3,326 3,109 + 7 3,227 2,998 + 8

Natural gas sales
per 1,000 shares
(Mcf) 358 312 + 15 1,356 1,192 + 14

Oil and NGLs sales
(bbls/d) 229,232 247,606 - 7 227,065 260,383 - 13

Oil and NGLs sales
per 1,000 shares
(Mcfe) 148 149 - 1 573 621 - 8

Total sales
(MMcfe/d) 4,701 4,595 + 2 4,589 4,560 + 1

Total sales per
1,000 shares (Mcfe) 506 461 + 10 1,929 1,813 + 6

Net wells drilled 1,150 958 + 20 4,676 4,956 - 6

Continuing Operations

North America Natural
Gas sales (MMcf/d) 3,326 3,087 + 8 3,227 2,968 + 9

North America Oil
and NGLs (bbls/d) 159,289 159,470 - 156,000 166,417 - 6

Total sales
(MMcfe/d) 4,282 4,044 + 6 4,163 3,966 + 5

Net wells drilled 1,142 952 + 20 4,658 4,923 - 5

Resource play growth

Key resource play production growth up about 18 percent in 2005
EnCana's resource play production is approaching 80 percent of EnCana's total production from continuing operations. The company's growth continues to be led by the core of its operations, 10 key resource plays located from northern British Columbia to Texas, which now represent about 55 percent of total production from continuing operations. In 2005, gas and oil production from these key resource plays increased about 18 percent compared to 2004. Production from EnCana's Foster Creek steam-assisted gravity drainage project averaged about 40,000 barrels per day in December, while total in-situ oilsands production exceeded 50,000 barrels per day in December. Expansion at Foster Creek during 2006 is expected to increase productive capacity to 60,000 barrels per day by year-end.

Growth from key North American resource plays

Daily Production

Resource Play 2005

2005 Q4 Q3 Q2 Q1

Natural Gas (MMcf/d)
Jonah 435 454 440 416 431
Piceance 307 326 302 302 300
East Texas 90 98 94 85 82

Fort Worth 70 88 66 63 61
Greater Sierra 219 226 225 228 195
Cutbank Ridge 92 125 105 80 56
CBM 57 77 62 51 38
Shallow Gas 625 625 616 633 625

Oil (Mbbls/d)
Foster Creek 29 35 27 24 30
Pelican Lake 26 28 27 27 21

Total (MMcfe/d) 2,224 2,392 2,235 2,166 2,096

% change from prior
year's quarter 17.6 13.1 16.6 23.6

% change from prior period 17.5 7.0 3.2 3.3 3.0

Daily Production

Resource Play 2004

2004 Q4 Q3 Q2 Q1

Natural Gas (MMcf/d)
Jonah 389 404 373 387 394
Piceance 261 291 282 251 218
East Texas 50 83 81 36 -
Fort Worth 27 34 31 23 21
Greater Sierra 230 211 244 247 216
Cutbank Ridge 40 50 45 41 22
CBM 17 27 19 11 10
Shallow Gas 592 629 595 590 554

Oil (Mbbls/d)
Foster Creek 29 28 29 30 28
Pelican Lake 19 23 22 15 15

Total (MMcfe/d) 1,892 2,034 1,976 1,858 1,696

% change from prior
year's quarter

% change from prior period 33.6 2.9 6.4 9.6 7.1

Drilling activity in key North American resource plays

Resource Play Net Wells Drilled

2005 2005 2004
Full ---------------------------- Full
Year Q4 Q3 Q2 Q1 Year

Natural Gas
Jonah 104 21 25 30 28 70
Piceance 266 55 69 65 77 250
East Texas 84 20 21 22 21 50
Fort Worth 59 20 18 12 9 36
Greater Sierra 164 25 33 47 59 187
Cutbank Ridge 135 34 40 38 23 50
CBM 1,084 327 216 219 322 760
Shallow Gas 1,267 288 341 365 273 1,552

Oil
Foster Creek 39 13 14 2 10 11
Pelican Lake 52 - 3 33 16 92

Total net wells 3,254 803 780 833 838 3,058

Year-end 2005 proved reserves

NOTE: Due to low commodity prices at the end of 2004 and in accordance with regulatory requirements, EnCana removed its proved bitumen reserves from its books. At the end of 2005, prices improved and all of those previously-removed reserves were reinstated. The following reserves descriptions exclude the impact of the 2004 bitumen revision.

EnCana achieved 18 percent proved reserves growth at competitive cost

Total proved reserves
- Proved reserves increased 18 percent to 18.5 Tcfe
- Proved reserves, excluding bitumen, increased 8 percent to 14.6 Tcfe
- Total proved reserves additions were 4.5 Tcfe, compared to production of 1.7 Tcfe
- Total proved reserves additions, excluding bitumen, were 2.7 Tcfe, compared to production of 1.6 Tcfe

Natural gas reserves
- Proved gas reserves increased 13 percent to 11.8 Tcf
- Proved gas additions were 2.5 Tcf, 100 percent organic
- Gas production replacement of 213 percent

Oil and NGLs reserves
- Proved oil and NGLs reserves increased 30 percent to 1.1 billion bbls, 100 percent organic
- Proved oil and NGLs additions were 340 million bbls compared to production of 84 million bbls
- Oil and NGLs production replacement of 406 percent

Bitumen reserves (included in crude oil and NGLs)
- Bitumen reserves up 81 percent to 657 million bbls
- Proved bitumen additions were 309 million bbls compared to production of 14 million bbls
- Reinstated 363 million bbls of bitumen reserves that were removed due to low bitumen prices at year-end 2004

Reserves additions costs
- Three-year reserve replacement costs averages $1.22 per Mcfe
- Finding and development costs of $1.29 per Mcfe
- Finding and development costs excluding bitumen reserves additions of $1.93 per Mcfe
- Reserve replacement costs of 91 cents per Mcfe
- Reserve replacement costs excluding bitumen reserves additions of

$1.37 per Mcfe

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

2005 Proved Reserves Reconciliation

Crude oil and
Natural Gas
Natural gas Liquids
(Bcf) (MMbbls)

Canada
Canada USA Total Conven- Canada
tional Bitumen

Start of 2005 5,824 4,636 10,460 266.9 0.0
Revisions & improved
recovery 202 (260) (58) 47.5 174.6
Extensions & discoveries 1,289 1,252 2,541 14.1 134.0
Acquisitions 7 76 83 - -
Divestitures (30) (37) (67) (15.1) -
Production (775) (400) (1,175) (38.3) (13.9)

End of year before bitumen
reinstatement 6,517 5,267 11,784 275.1 294.7
Reinstatement of bitumen - - - - 362.7

End of 2005 6,517 5,267 11,784 275.1 657.4

Developed 4,513 2,718 7,231 215.9 102.8

Undeveloped 2,004 2,549 4,553 59.2 554.6

Total 6,517 5,267 11,784 275.1 657.4

2005 Reserves Growth

Start of 2005 plus
reinstated bitumen reserves 5,824 4,636 10,460 266.9 362.7

End of 2005 6,517 5,267 11,784 275.1 657.4

% Change(1) + 12 + 14 + 13 + 3 + 81

2005 Proved Reserves Reconciliation

Crude oil and Natural Gas Liquids Total
(MMbbls) Bcfe

Canada USA Ecuador Total
Total

Start of 2005 266.9 91.0 143.3 501.2 13,467
Revisions & improved
recovery 222.1 (3.2) 8.1 227.0 1,305
Extensions & discoveries 148.1 8.9 10.2 167.2 3,544
Acquisitions - 0.4 - 0.4 85
Divestitures (15.1) (39.0) - (54.1) (392)

Production (52.2) (5.0) (26.6) (83.8) (1,678)

End of year before bitumen
reinstatement 569.8 53.1 135.0 757.9 16,331
Reinstatement of bitumen 362.7 - - 362.7 2,176

End of 2005 932.5 53.1 135.0 1,120.6 18,507

Developed 318.7 32.2 104.0 454.9 9,960

Undeveloped 613.8 20.9 31.0 665.7 8,547

Total 932.5 53.1 135.0 1,120.6 18,507

2005 Reserves Growth

Start of 2005 plus
reinstated bitumen reserves 629.6 91.0 143.3 863.9(1) 15,643

End of 2005 932.5 53.1 135.0 1,120.6 18,507

% Change(1) + 48 - 42 - 6 + 30 + 18
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(1) EnCana's growth in proved reserves in 2005 is expressed as the percentage change from the start to the end of the year. For bitumen reserves reporting, all of the reserves that were revised downward at the end of 2004 were reinstated at the end of 2005, due to favourable commodity prices. Therefore, EnCana's 2005 growth in crude oil and NGLs reserves is based on a start of year balance that includes its conventional oil reserves of 501.2 million barrels, plus its 362.7 million barrels of reinstated bitumen reserves for a total oil start of year balance of 863.9 million barrels.

Bitumen reserves add to long life potential
EnCana's proved bitumen reserves of 657 million barrels are estimated to be sufficient to sustain approximately 30 years of anticipated production at Foster Creek's forecast 2006 year-end productive capacity of 60,000 barrels per day. The company believes that significant future reserve addition potential exists associated with EnCana's previously announced in-situ oilsands development plans, which have the potential to increase current production about 10-fold to more than 500,000 barrels per day by 2015.

EnCana continues to grow reserves at competitive costs
"EnCana continues to deliver solid reserves growth at competitive costs. For the past three years, EnCana's production replacement has averaged more than 200 percent and even in 2005's high cost environment, our year-end finding and development costs were $1.29 per thousand cubic feet equivalent. When you look at this performance in light of our 2005 netback of $5.21 per thousand cubic feet equivalent, you can see that EnCana's significant proved reserves have added substantial value," Eresman said.

Proved Reserves Costs

Cumulative
Capital investment ($ millions) 2005 2004 2003 2003-05

Finding and development 6,231 4,792 4,095 15,118
Acquisitions 472 3,469 558 4,499
Divestitures (2,552) (3,827) (312) (6,691)

Net capital investment 4,151 4,434 4,341 12,926

Total reserve additions (Bcfe) 4,542 3,163 2,893 10,598

3-year
average

Reserve replacement cost ($/Mcfe) 0.91 1.40 1.50 1.22

Finding and development cost 1.29 1.44 1.43 1.37

Finding, development and
acquisition cost 1.36 1.70 1.46 1.51

NOTE: This table excludes the impact of the bitumen reserves revisions of
2004 and bitumen reserves reinstatement in 2005.

2005 natural gas and oil prices

2005 Natural Gas and Oil Prices
(excludes financial hedging)

Q4 Q4 % %
Natural gas ($/Mcf) 2005 2004 Change 2005 2004 Change
NYMEX Price 12.96 7.10 + 83 8.62 6.14 + 40
Realized Gas Price 10.29 6.08 + 69 7.46 5.47 + 36

Oil and NGLs ($/bbl)
WTI Price 60.05 48.27 + 24 56.70 41.47 + 37
Bow River Differential 22.79 19.14 + 19 19.64 12.82 + 53
Realized Liquids Price 37.16 30.20 + 23 36.17 28.77 + 26
NAPO Differential 23.38 19.17 + 22 18.37 14.33 + 28

Price risk management
Detailed risk management positions at December 31, 2005 are presented in Note 13 to the 2005 unaudited consolidated financial statements. In 2005, EnCana's financial price risk management measures resulted in realized losses of approximately $527 million after-tax, comprised of a $288 million loss on oil hedges, a $261 million loss on gas hedges and a $22 million gain on other hedges. The company's hedging strategy currently employs primarily put options to protect against downside risk without limiting upside in a rising price environment.

More than 90 percent of 2006 gas sales has downside price protection
In the fourth quarter of 2005, EnCana added approximately 1.6 billion cubic feet per day of NYMEX put options at an average strike price of $8.42 per thousand cubic feet. EnCana now has approximately 71 percent of 2006 forecast gas sales hedged with put options with an average strike price of $7.76 per thousand cubic feet. Another 22 percent of 2006 forecast gas production is hedged with fixed price instruments with an average price of $5.83 per thousand cubic feet. Most of these fixed price positions relate to hedges initiated in 2004 when EnCana acquired Tom Brown, Inc. (TBI). The TBI hedges expire at the end of 2006. Of EnCana's 2006 forecast oil and NGLs sales, about 91 percent is exposed to price upside, while about 45 percent has downside protection.
North American natural gas prices are impacted by volatile pricing disconnects caused primarily by transportation constraints between producing regions and consuming regions. These price discounts are called basis differentials. For 2006 EnCana has hedged 100 percent of its U.S. Rockies basis differential at $0.65 per thousand cubic feet. In Canada for 2006,

EnCana has hedged 35 percent of its AECO basis differential at $0.69 per thousand cubic feet and has an additional 39 percent subject to transport and aggregator contracts.

Operations

Operational challenges in 2005

Throughout 2005, the operational challenges facing the North American natural gas and oil industry intensified. With record prices for each commodity, the drive for new supplies increased the demand and prices for rigs. This high activity level sparked industry inflation of 15 to 30 percent for overall goods and services. With EnCana's large volume purchasing power and longer term planning initiatives, the company contained its inflation to the low end of the industry range in 2005.

On top of a hectic industry came unusual weather events rarely seen in Alberta, the heartland of EnCana's Canadian operations. Three major rain storms in June flooded rivers, homes and businesses and brought many of EnCana's drilling operations to a standstill. The wettest June ever recorded in Alberta caused delays through the year - a total of about two to three months of down time in field operations. The activity-related operational delays were widespread in 2005, whereas the poorer operating conditions affected EnCana more specifically in some of its most active areas. By year-end, EnCana had drilled about 80 percent of its planned gas wells and achieved about 80 percent of its forecast gas production additions (additions to offset decline plus additions to create planned growth). Although the company was unable to complete its entire gas drilling program in 2005 due to the highly unusual conditions, the estimated outlook for the company's base production and new well additions remains solid and predictable.

2005 capital investment

EnCana's upstream capital investment of about $6.2 billion was approximately $600 million higher than EnCana's corporate guidance. This increase in capital was due principally to the following: a $100 million increase in land acquisitions, largely Central Alberta lands purchased in December; $200 million due to acceleration of drilling of coalbed methane wells and the expansion of in-situ oilsands projects; $200 million due to higher inflation and inefficiencies generated by the pace of field activity and weather related delays; and $100 million due to the impact of foreign exchange.

Bringing new drilling equipment to market

"As we move into 2006, the North American operating market remains robust. We currently have about 145 rigs drilling across the continent. In an effort to help alleviate the pressure on equipment, we have negotiated long-term contracts that are intended to add about 60 new fit-for-purpose rigs to our contract fleet. We also have contracted fixed prices for about 50 percent of our planned 2006 expenditures. And we are investing in the human resources to help staff the equipment with financial support to post-secondary institutions training new field workers," Eresman said.

EnCana expands resource play concept to Europe

On February 7, 2006, the Government of France granted EnCana a 100 percent interest in a permit to explore about 860,000 acres of land in southwest France. EnCana plans a multi-well exploration drilling program on the Foix Permit lands to identify the potential for natural gas resource play development.

Corporate developments

Randy Eresman takes over as President & Chief Executive Officer; Brian Ferguson named CFO

On January 1, 2006, Randy Eresman became President & Chief Executive Officer and a Director of EnCana. On December 14, 2005, EnCana announced that effective March 1, 2006, Brian Ferguson, currently Executive Vice-President, Corporate Development, will succeed John Watson as Executive Vice-President & Chief Financial Officer.

Additional EnCana executive appointments

On January 1, 2006, Hayward Walls, previously EnCana's Vice-President of Information Technology and Chief Information Officer (CIO), was appointed Executive Vice-President, Corporate Services, replacing Drude Rimell, who retired. Walls continues as CIO.

In early January, Randy Eresman announced other executive team appointments. In order to expand expertise across the organization and broaden the knowledge and experience among the company's leaders, as of March 1, 2006, Roger Biemans, currently President of EnCana Oil & Gas (USA) Inc., is appointed President of the Canadian Plains Region. Jeff Wojahn, currently President of Canadian Plains Region, is appointed President, EnCana Oil & Gas (USA) Inc. Don Swystun, currently President of Ecuador Region, is appointed Executive Vice-President, Corporate Development, where he will lead acquisitions, divestitures and reserves. Sherri Brillon, Vice-President, Strategic Planning and Portfolio Management, joined EnCana's executive team on January 1, 2006.

Quarterly dividend of 7.5 cents per share declared

EnCana's board of directors has declared a quarterly dividend of 7.5 cents per share which is payable on March 31, 2006 to common shareholders of record as of March 15, 2006.

EnCana Normal Course Issuer Bid purchases

In 2005, under its previous Normal Course Issuer Bid, EnCana purchased about 55.2 million common shares, representing approximately 6.1 percent of the company's outstanding shares on December 31, 2004, at an average price of approximately $34.85 per common share. To date in 2006, EnCana has purchased 6.8 million common shares under its current Normal Course Issuer Bid, which was renewed in October 2005, for approximately $314 million at an average price of $46.34 per share. Under the renewed bid, EnCana may purchase for cancellation over a period ending October 30, 2006 up to 85,603,640 of its common shares, representing 10 percent of the public float of approximately 856,036,400 common shares outstanding as at October 25, 2005.

Financial strength

EnCana targets a net debt-to-capitalization ratio between 30 and 40 percent. At December 31, 2005, the company's net debt-to-capitalization ratio was 33:67. EnCana's net debt-to-EBITDA multiple, on a trailing 12-month basis, was 1.1 times.

CONFERENCE CALL TODAY

EnCana Corporation will host a conference call today, Wednesday, February 15, 2006 starting at 11 a.m., Mountain Time (1 p.m. Eastern Time), to discuss EnCana's fourth quarter and year-end 2005 financial and operating results.

To participate, please dial (913) 981-4911 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 3 p.m. MT on February 15 until midnight February 22, 2006 by dialling (888) 203-1112 or (719) 457-0820 and entering access code 8924369.

A live audio webcast of the conference call will also be available via EnCana's website, www.encana.com, under Investor Relations. The webcast will be archived for approximately 90 days.

NOTE 1: Non-GAAP measures
This news release contains references to cash flow, total operating earnings and free cash flow.

- Total operating earnings is a non-GAAP measure that shows net earnings excluding non-operating items such as the after-tax impacts of a gain on the sale of discontinued operations, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued in Canada and the effect of the reduction in income tax rates.

Management believes these items reduce the comparability of the company's underlying financial performance between periods. The majority of the unrealized gains/losses that relate to U.S. dollar debt issued in Canada are for debt with maturity dates in excess of five years.

- Free cash flow is a non-GAAP measure that EnCana defines as cash flow in excess of capital investment and net acquisitions and divestitures.

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding EnCana's liquidity and its ability to generate funds to finance its operations.

EnCana Corporation
With an enterprise value of approximately US$43 billion, EnCana is one of North America's leading natural gas producers, the largest holder of gas and oil resource lands onshore North America and is a technical and cost leader in the in-situ recovery of oilsands bitumen. EnCana delivers predictable, reliable, profitable growth from its portfolio of long-life resource plays situated in Canada and the United States. Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average decline rates and longer producing lives than conventional plays. The application of technology to unlock the huge resource potential of these plays typically results in continuous increases in production and reserves and decreases in costs over multiple decades of resource play life. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

RESERVE COST DEFINITIONS - Production replacement is calculated by dividing reserve additions by production in the same period. Reserve additions over a given period, in this case 2005, are calculated by summing one or more of revisions and improved recovery, extensions and discoveries, acquisitions and divestitures. Reserve replacement cost is calculated by dividing total capital invested in finding, development and acquisitions net of divestitures by reserve additions in the same period. Finding and development cost is calculated by dividing total capital invested in finding and development activities by additions to proved reserves, before acquisitions and divestitures, which is the sum of revisions, extensions and discoveries. Finding, development and acquisition cost is calculated by dividing total capital invested in finding, development and acquisition activities by additions to proved reserves, before divestitures, which is the sum of revisions, extensions, discoveries and acquisitions. Proved reserves added in 2005 included both developed and undeveloped quantities. Additions to EnCana's proved undeveloped reserves were consistent with EnCana's resource play focus. The company estimates that approximately two-thirds of its proved undeveloped reserves will be developed within the next three years. 2005 finding, development and acquisition capital includes investment in long lead time projects. EnCana uses the aforementioned metrics as indicators of relative performance, along with a number of other measures. Many performance measures exist, all measures have limitations and historical measures are not necessarily indicative of future performance.

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

In this news release, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Also, certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the same basis. BOE and cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Unbooked resource potential
EnCana defines unbooked resource potential as quantities of oil and natural gas on existing landholdings that are not yet classified as proved reserves, but which EnCana believes may be moved into the proved reserves category and produced in the future. EnCana employs a probability-weighted approach in the calculation of these quantities, including statistical distributions of resource play performance and areal extent. Consequently, EnCana's unbooked resource potential necessarily includes quantities of probable and possible reserves and contingent resources, as these terms are defined in the Canadian Oil and Gas Evaluation Handbook.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this news release include, but are not limited to: future economic and operating performance (including per share growth, cash flow and increase in net asset value); anticipated life of proved reserves; anticipated unbooked resource potential; anticipated conversion of unbooked resource potential to proved reserves; anticipated growth and success of resource plays and the expected characteristics of resource plays; planned divestitures of the Ecuador assets and other non-core assets and the company's natural gas storage business; the expected proceeds from planned divestitures; planned expansion of in-situ oilsands production; anticipated crude oil and natural gas prices; anticipated expansion and production at Foster Creek; anticipated drilling on the Foix Permit lands; anticipated drilling inventory; expected proportion of total production and cash flows contributed by natural gas; anticipated success of EnCana's market risk mitigation strategy and EnCana's ability to participate in commodity price upside and to protect against high U.S. Rockies gas price basis differentials; anticipated purchases pursuant to the Normal Course Issuer Bid; estimated recycle ratios; potential demand for natural gas; anticipated production in 2006 and beyond; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs sales in 2006 and beyond; anticipated costs and inflationary pressures; potential risks associated with drilling and references to potential exploration.
Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown

risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon the company's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; risks associated with technology; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the company operates, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.
Furthermore, the forward-looking statements contained in this news release are made as of the date of this news release, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

Interim Consolidated Financial Statements
(unaudited)
For the period ended December 31, 2005

EnCana Corporation

U.S. DOLLARS

Notice to Reader

The draft financial statements are provided for your information; the reader should be aware the financial statements are still under review and changes may be made. The financial statements are confidential and are not to be distributed.

CONSOLIDATED STATEMENT OF EARNINGS (unaudited)

Three Months Ended Twelve Months Ended
December 31, December 31,
($ millions, except ---
per share amounts) 2005 2004 2005 2004

REVENUES,
NET OF ROYALTIES (Note 2)

Upstream $ 3,452 $ 2,003 $ 10,465 $ 7,256
Market Optimization 1,417 929 4,267 3,200
Corporate
- Unrealized gain
(loss) on risk
management 991 610 (466) (198)
- Other - - - 1

5,860 3,542 14,266 10,259

EXPENSES (Note 2)
Production and
mineral taxes 162 95 453 311
Transportation
and selling 138 106 538 490
Operating 452 309 1,438 1,099
Purchased product 1,376 905 4,159 3,092
Depreciation,
depletion and
amortization 751 636 2,769 2,379
Administrative 63 61 268 197
Interest, net (Note 5) 104 114 524 398
Accretion of
asset retirement
obligation (Note 9) 10 6 37 22
Foreign exchange
(gain) loss, net (Note 6) 37 (199) (24) (412)
Stock-based
compensation -
options (Note 10) 3 3 15 17
(Gain) on
divestitures (Note 4) - (24) - (59)

3,096 2,012 10,177 7,534

NET EARNINGS BEFORE
INCOME TAX 2,764 1,530 4,089 2,725
Income tax
expense (Note 7) 895 475 1,260 632

NET EARNINGS FROM
CONTINUING
OPERATIONS 1,869 1,055 2,829 2,093
NET EARNINGS FROM
DISCONTINUED
OPERATIONS (Note 3) 497 1,525 597 1,420

NET EARNINGS $ 2,366 $ 2,580 $ 3,426 $ 3,513

NET EARNINGS FROM
CONTINUING
OPERATIONS PER
COMMON SHARE (Note 12)
Basic $ 2.19 $ 1.15 $ 3.26 $ 2.27
Diluted $ 2.14 $ 1.13 $ 3.18 $ 2.24

NET EARNINGS PER
COMMON SHARE (Note 12)
Basic $ 2.77 $ 2.81 $ 3.95 $ 3.82
Diluted $ 2.71 $ 2.77 $ 3.85 $ 3.75

CONSOLIDATED STATEMENT OF RETAINED EARNINGS (unaudited)

	Twelve Months Ended December 31,	
($ millions)	2005	2004
RETAINED EARNINGS, BEGINNING OF YEAR	$ 7,935	$ 5,276
Net Earnings	3,426	3,513
Dividends on Common Shares	(238)	(183)
Charges for Normal Course Issuer Bid (Note 10)	(1,642)	(671)
RETAINED EARNINGS, END OF YEAR	$ 9,481	$ 7,935

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET (unaudited)

	As at December 31,	As at December 31,
($ millions)	2005	2004
ASSETS		
Current Assets		
Cash and cash equivalents	$ 105	$ 593
Accounts receivable and accrued revenues	1,851	1,566
Risk management (Note 13)	495	317
Inventories	103	58
Assets of discontinued operations (Note 3)	1,050	971
	3,604	3,505
Property, Plant and Equipment, net (Note 2)	24,881	22,503
Investments and Other Assets	496	334
Risk Management (Note 13)	530	87
Assets of Discontinued Operations (Note 3)	2,113	2,325
Goodwill	2,524	2,459
(Note 2)	$ 34,148	$ 31,213
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 2,741	$ 1,742
Income tax payable	392	357
Risk management (Note 13)	1,227	224
Liabilities of discontinued operations (Note 3)	438	436
Current portion of long-term debt (Note 8)	73	188
	4,871	2,947
Long-Term Debt (Note 8)	6,703	7,742
Other Liabilities	93	118
Risk Management (Note 13)	102	192
Asset Retirement Obligation (Note 9)	816	611

Liabilities of Discontinued
Operations (Note 3) 267 213
Future Income Taxes 5,289 5,082

18,141 16,905

Shareholders' Equity
Share capital (Note 10) 5,131 5,299
Share options, net - 10
Paid in surplus 133 28
Retained earnings 9,481 7,935
Foreign currency translation
adjustment 1,262 1,036

16,007 14,308

$ 34,148 $ 31,213

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS (unaudited)

Three Months Ended Twelve Months Ended
December 31, December 31,

($ millions) 2005 2004 2005 2004

OPERATING ACTIVITIES
Net earnings from
continuing
operations $ 1,869 $ 1,055 $ 2,829 $ 2,093
Depreciation,
depletion and
amortization 751 636 2,769 2,379
Future income
taxes (Note 7) 717 422 56 73
Cash tax on sale
of assets (13) - 578 -
Unrealized (gain)
loss on risk
management (Note 13) (985) (610) 469 191
Unrealized
foreign exchange
loss (gain) 28 (163) (50) (285)
Accretion of
asset retirement
obligation (Note 9) 10 6 37 22
(Gain) on
divestitures (Note 4) - (24) - (59)
Other 13 36 274 88

Cash flow from
continuing
operations 2,390 1,358 6,962 4,502
Cash flow from
discontinued
operations 120 133 464 478

Cash flow 2,510 1,491 7,426 4,980
Net change in
other assets

and liabilities (108) (105) (281) (176)
Net change in
non-cash working
capital from
continuing
operations 1,165 1,936 497 1,565
Net change in
non-cash working
capital from
discontinued
operations (140) (2,034) (212) (1,778)

3,427 1,288 7,430 4,591

INVESTING ACTIVITIES
Business
combination with
Tom Brown, Inc. - - - (2,335)
Capital
expenditures (Note 2) (2,362) (1,489) (6,925) (4,763)
Proceeds on
disposal of
assets (Note 4) 30 94 2,523 1,456
Cash tax on
sale of assets 13 - (578) -
Equity investments - (5) - 47
Net change in
investments
and other (161) 73 (109) 44
Net change in
non-cash working
capital from
continuing
operations 165 71 330 (29)
Discontinued
operations 572 1,951 239 1,321

(1,743) 695 (4,520) (4,259)

FINANCING ACTIVITIES
Net (repayment)
issuance of
revolving
long-term debt (1,513) 287 (538) 72
Repayment of
long-term debt (145) (1,005) (1,104) (2,759)
Issuance of
long-term debt - - 429 3,761
Issuance of
common shares (Note 10) 24 97 294 281
Purchase of
common shares (Note 10) - (774) (2,114) (1,004)
Dividends on
common shares (64) (46) (238) (183)
Other (17) 6 (125) (5)

(1,715) (1,435) (3,396) 163

DEDUCT: FOREIGN
EXCHANGE LOSS ON
CASH AND CASH
EQUIVALENTS HELD
IN FOREIGN CURRENCY 1 6 2 6

(DECREASE) INCREASE
IN CASH AND CASH
EQUIVALENTS (32) 542 (488) 489
CASH AND CASH
EQUIVALENTS,
BEGINNING OF YEAR 137 51 593 104

CASH AND CASH
EQUIVALENTS,
END OF YEAR $ 105 $ 593 $ 105 $ 593

See accompanying Notes to Consolidated Financial Statements.

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

1. BASIS OF PRESENTATION

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

The interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2004. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2004.

2. SEGMENTED INFORMATION

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

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

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

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

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

Operations that have been discontinued are disclosed in Note 3.

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

	Upstream		Market Optimization	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 3,452	$ 2,003	$ 1,417	$ 929
Expenses				
Production and mineral taxes	162	95	-	-
Transportation and selling	135	102	3	4
Operating	415	286	32	20
Purchased product	-	-	1,376	905
Depreciation, depletion and amortization	731	614	1	5
Segment Income (Loss)	$ 2,009	$ 906	$ 5	$ (5)

	Corporate(*)		Consolidated	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 991	$ 610	$ 5,860	$ 3,542
Expenses				
Production and mineral taxes	-	-	162	95
Transportation and selling	-	-	138	106
Operating	5	3	452	309
Purchased product	-	-	1,376	905
Depreciation, depletion and amortization	19	17	751	636
Segment Income (Loss)	$ 967	$ 590	2,981	1,491
Administrative			63	61
Interest, net			104	114
Accretion of asset retirement obligation			10	6
Foreign exchange loss (gain), net			37	(199)
Stock-based compensation - options			3	3
(Gain) on divestitures			-	(24)
			217	(39)
Net Earnings Before Income Tax			2,764	1,530
Income tax expense			895	475
Net Earnings From Continuing				

Operations $ 1,869 $ 1,055

(*) For the three months ended December 31, the pre-tax unrealized gain (loss) on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 13):

	2005	2004
Revenues, Net of Royalties - Corporate	$ 991	$ 610
Operating Expenses and Other - Corporate	6	-
Total Unrealized Gain on Risk Management before-tax - Continuing Operations	$ 985	$ 610

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

	Upstream Canada		United States	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 2,258	$ 1,313	$ 1,106	$ 628
Expenses				
Production and mineral taxes	29	26	133	69
Transportation and selling	87	75	48	27
Operating	227	180	64	39
Depreciation, depletion and amortization	511	455	166	145
Segment Income	$ 1,404	$ 577	$ 695	$ 348

	Other		Total Upstream	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 88	$ 62	$ 3,452	$ 2,003
Expenses				
Production and mineral taxes	-	-	162	95
Transportation and selling	-	-	135	102
Operating	124	67	415	286
Depreciation, depletion and amortization	54	14	731	614
Segment Income (Loss)	$ (90)	$ (19)	$ 2,009	$ 906

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

Produced Gas Produced Gas

Canada United States Total

	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties	$ 1,852	$ 1,041	$ 1,041	$ 578	$ 2,893	$ 1,619
Expenses						
Production and mineral taxes	20	19	127	63	147	82
Transportation and selling	72	74	48	27	120	101
Operating	144	103	64	39	208	142
Operating Cash Flow	$ 1,616	$ 845	$ 802	$ 449	$ 2,418	$ 1,294

Oil & NGLs Oil & NGLs

	Canada		United States		Total	
	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties	$ 406	$ 272	$ 65	$ 50	$ 471	$ 322
Expenses						
Production and mineral taxes	9	7	6	6	15	13
Transportation and selling	15	1	-	-	15	1
Operating	83	77	-	-	83	77
Operating Cash Flow	$ 299	$ 187	$ 59	$ 44	$ 358	$ 231

Other & Total Upstream Other Total Upstream

	2005	2004	2005	2004
Revenues, Net of Royalties	$ 88	$ 62	$ 3,452	$ 2,003
Expenses				
Production and mineral taxes	-	-	162	95
Transportation and selling	-	-	135	102
Operating	124	67	415	286
Operating Cash Flow	$ (36)	$ (5)	$ 2,740	$ 1,520

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

Upstream Market Optimization

	2005	2004	2005	2004

Revenues, Net of Royalties	$ 10,465	$ 7,256	$ 4,267	$ 3,200
Expenses				
Production and mineral taxes	453	311	-	-
Transportation and selling	525	472	13	18
Operating	1,351	1,026	85	74
Purchased product	-	-	4,159	3,092
Depreciation, depletion and amortization	2,688	2,271	8	47
Segment Income (Loss)	$ 5,448	$ 3,176	$ 2	$ (31)

	Corporate(*)		Consolidated	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ (466)	$ (197)	$ 14,266	$ 10,259
Expenses				
Production and mineral taxes	-	-	453	311
Transportation and selling	-	-	538	490
Operating	2	(1)	1,438	1,099
Purchased product	-	-	4,159	3,092
Depreciation, depletion and amortization	73	61	2,769	2,379
Segment Income (Loss)	$ (541)	$ (257)	4,909	2,888
Administrative			268	197
Interest, net			524	398
Accretion of asset retirement obligation			37	22
Foreign exchange (gain), net			(24)	(412)
Stock-based compensation - options			15	17
(Gain) on divestitures			-	(59)
			820	163
Net Earnings Before Income Tax			4,089	2,725
Income tax expense			1,260	632
Net Earnings From Continuing Operations			$ 2,829	$ 2,093

(*) For the twelve months ended December 31, the pre-tax unrealized loss on risk management is recorded in the Consolidated Statement of Earnings as follows (see Note 13):

	2005	2004
Revenues, Net of Royalties - Corporate	$ (466)	$ (197)
Operating Expenses and Other - Corporate	3	(6)
Total Unrealized (Loss) on Risk Management before-tax - Continuing Operations	$ (469)	$ (191)

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

Upstream	Canada		United States	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 7,005	$ 5,083	$ 3,177	$ 1,941
Expenses				
Production and mineral taxes	104	87	349	224
Transportation and selling	343	352	182	120
Operating	826	685	212	119
Depreciation, depletion and amortization	1,927	1,751	682	475
Segment Income	$ 3,805	$ 2,208	$ 1,752	$ 1,003

	Other		Total Upstream	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 283	$ 232	$ 10,465	$ 7,256
Expenses				
Production and mineral taxes	-	-	453	311
Transportation and selling	-	-	525	472
Operating	313	222	1,351	1,026
Depreciation, depletion and amortization	79	45	2,688	2,271
Segment Income (Loss)	$ (109)	$ (35)	$ 5,448	$ 3,176

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

	Produced Gas		Produced Gas			
	Canada		United States		Total	
	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties	$ 5,486	$ 3,928	$ 2,932	$ 1,776	$ 8,418	$ 5,704
Expenses						
Production and mineral taxes	76	65	325	205	401	270
Transportation and selling	283	296	182	120	465	416
Operating	521	400	212	119	733	519
Operating Cash Flow	$ 4,606	$ 3,167	$ 2,213	$ 1,332	$ 6,819	$ 4,499

	Oil & NGLs				Oil & NGLs	
	Canada		United States		Total	
	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties	$ 1,519	$ 1,155	$ 245	$ 165	$ 1,764	$ 1,320
Expenses						
Production and mineral taxes	28	22	24	19	52	41
Transportation and selling	60	56	-	-	60	56
Operating	305	285	-	-	305	285
Operating Cash Flow	$ 1,126	$ 792	$ 221	$ 146	$ 1,347	$ 938

Other & Total Upstream	Other		Total Upstream	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ 283	$ 232	$ 10,465	$ 7,256
Expenses				
Production and mineral taxes	-	-	453	311
Transportation and selling	-	-	525	472
Operating	313	222	1,351	1,026
Operating Cash Flow	$ (30)	$ 10	$ 8,136	$ 5,447

Capital Expenditures (Continuing Operations)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2005	2004	2005	2004
Upstream Core Capital				
Canada	$ 1,370	$ 733	$ 4,150	$ 3,015
United States	633	398	1,982	1,249
Other Countries	31	30	70	79
	2,034	1,161	6,202	4,343
Upstream Acquisition Capital				
Canada	4	9	30	64
United States	227	297	418	300
	231	306	448	364
Market Optimization	68	4	197	10
Corporate	29	18	78	46

Total $ 2,362 $ 1,489 $ 6,925 $ 4,763

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at December 31,		As at December 31,	
	2005	2004	2005	2004
Upstream	$ 24,247	$ 22,097	$ 28,858	$ 26,118
Market Optimization	371	167	597	414
Corporate	263	239	1,530	1,385
Assets of Discontinued Operations (Note 3)			3,163	3,296
Total	$ 24,881	$ 22,503	$ 34,148	$ 31,213

3. DISCONTINUED OPERATIONS

Midstream

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

During the fourth quarter of 2005, EnCana decided to divest of its natural gas storage operations. EnCana's natural gas storage operations include the 100 percent interest in the AECO storage facility as well as facilities in the United States.

Ecuador

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

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

On September 13, 2005, EnCana announced it had reached an agreement to sell all its interest in its Ecuador operations for $1.42 billion, which is approximately equivalent to the asset's net book value at July 1, 2005, the referenced effective date of the transaction. Included in net earnings for 2005 is a provision of $234 million which has been recorded against the net book value to recognize management's best estimate of the difference between the selling price and the December 31, 2005 underlying accounting value of the related investments at the sales date, as required under Canadian generally accepted accounting principles.

United Kingdom

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

Consolidated Statement of Earnings

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

For the three months ended December 31,	Ecuador		United Kingdom		Midstream	
	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties	$ 242	$ 173	$ -	$ 27	$ 645	$ 666
Expenses						
Production and mineral taxes	30	19	-	-	-	-
Transportation and selling	12	11	-	7	3	3
Operating	38	36	-	4	110	81
Purchased product	-	-	-	-	343	462
Depreciation, depletion and amortization	111	66	-	25	8	5
Administrative	-	-	-	-	30	-
Interest, net	(2)	(2)	-	(4)	(1)	(1)
Accretion of asset retirement obligation	-	-	-	-	-	-
Foreign exchange (gain) loss, net	(4)	4	(37)	(5)	-	(5)
(Gain) loss on discontinuance	-	-	-	(1,365)	(364)	(54)
	185	134	(37)	(1,338)	129	491
Net Earnings (Loss) Before Income Tax	57	39	37	1,365	516	175
Income tax expense	57	(1)	4	10	52	42
Net Earnings (Loss) From Discontinued Operations	$ -	$ 40	$ 33	$1,355	$ 464	$ 133

For the three months
ended December 31,

	Syncrude		Total	
	2005	2004	2005	2004
Revenues, Net of Royalties	$ -	$ (1)	$ 887	$ 865
Expenses				
Production and mineral taxes	-	-	30	19
Transportation and selling	-	-	15	21
Operating	-	-	148	121
Purchased product	-	-	343	462
Depreciation, depletion and amortization	-	-	119	96
Administrative	-	-	30	-
Interest, net	-	-	(3)	(7)
Accretion of asset retirement obligation	-	-	-	-
Foreign exchange (gain) loss, net	-	-	(41)	(6)
(Gain) loss on discontinuance	-	2	(364)	(1,417)
	-	2	277	(711)
Net Earnings (Loss) Before Income Tax	-	(3)	610	1,576
Income tax expense	-	-	113	51
Net Earnings (Loss) From Discontinued Operations	$ -	$ (3)	$ 497	$1,525

For the twelve months ended December 31,

	Ecuador		United Kingdom		Midstream	
	2005	2004	2005	2004	2005	2004
Revenues, Net of Royalties(*)	$ 965	$ 471	$ -	$ 153	$1,570	$1,551
Expenses						
Production and mineral taxes	131	61	-	-	-	-
Transportation and selling	58	60	-	36	9	9
Operating	138	125	-	36	301	251
Purchased product	-	-	-	-	1,100	1,184
Depreciation, depletion and amortization	234	263	-	118	28	23
Administrative	-	-	-	-	30	-
Interest, net	(2)	(3)	-	(9)	(2)	(1)
Accretion of asset retirement obligation	1	1	-	3	-	-

Foreign exchange
(gain) loss, net (4) 5 (40) (2) (2) (5)
(Gain) loss on
discontinuance - - - (1,365) (364) (54)

----

556 512 (40) (1,183) 1,100 1,407

Net Earnings (Loss)
Before Income Tax 409 (41) 40 1,336 470 144
Income tax expense
(recovery) 278 (8) 5 (2) 39 26

Net Earnings (Loss)
From Discontinued
Operations $ 131 $ (33) $ 35 $1,338 $ 431 $ 118

For the twelve months
ended December 31,

Syncrude Total

2005 2004 2005 2004

Revenues, Net of
Royalties(*) $ - $ (1) $2,535 $2,174

Expenses
Production and
mineral taxes - - 131 61
Transportation
and selling - - 67 105
Operating - - 439 412
Purchased product - - 1,100 1,184
Depreciation,
depletion and
amortization - - 262 404
Administrative - - 30 -
Interest, net - - (4) (13)
Accretion of
asset retirement
obligation - - 1 4
Foreign exchange
(gain) loss, net - - (46) (2)
(Gain) loss on
discontinuance - 2 (364) (1,417)

- 2 1,616 738

Net Earnings (Loss)
Before Income Tax - (3) 919 1,436
Income tax expense
(recovery) - - 322 16

Net Earnings (Loss)
From Discontinued
Operations $ - $ (3) $ 597 $1,420

(*) Revenues, net of royalties in Ecuador include realized losses of
$128 million related to derivative financial instruments. These
losses are offset by the reversal of the December 31, 2004 unrealized
mark to market losses of $72 million. In 2004, revenues, net of
royalties included realized losses of $278 million in addition to the

unrealized mark to market losses.

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

As at December 31, 2005	Ecuador	United Kingdom	Midstream	Total
Assets				
Cash and cash equivalents	$ 207	$ 8	$ (7)	$ 208
Accounts receivable and accrued revenues	137	-	271	408
Risk management	-	-	21	21
Inventories	23	-	390	413
	367	8	675	1,050
Property, plant and equipment, net	1,166	-	520	1,686
Investments and other assets	360	-	-	360
Goodwill	-	-	67	67
	$ 1,893	$ 8	$ 1,262	$ 3,163
Liabilities				
Accounts payable and accrued liabilities	$ 91	$ 27	$ 49	$ 167
Income tax payable	184	6	40	230
Risk management	-	-	41	41
	275	33	130	438
Asset retirement obligation	21	-	-	21
Future income taxes	162	(2)	86	246
	458	31	216	705
Net Assets of Discontinued Operations	$ 1,435	$ (23)	$ 1,046	$ 2,458

As at December 31, 2004	Ecuador	United Kingdom	Midstream	Syncrude	Total
Assets					
Cash and cash equivalents	$ 2	$ 12	$ 9	$ -	$ 23
Accounts receivable and accrued revenues	111	13	332	-	456
Risk management	3	-	19	-	22
Inventories	15	-	455	-	470
	131	25	815	-	971
Property, plant and					

equipment, net 1,295 - 637 - 1,932
Investments and other
assets 328 - - - 328
Goodwill - - 65 - 65

$ 1,754 $ 25 $ 1,517 $ - $ 3,296

Liabilities
Accounts payable and
accrued liabilities $ 61 $ 32 $ 137 $ 3 $ 233
Income tax payable 101 - 2 - 103
Risk management 72 - 17 - 89
----
234 32 156 3 425
Asset retirement
obligation 22 - - - 22
Future income taxes 80 11 111 - 202
----
336 43 267 3 649

Net Assets of
Discontinued Operations $ 1,418 $ (18) $ 1,250 $ (3) $ 2,647

Contingencies

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

In its filings, Occidental Petroleum Corporation indicated that it believes it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties. The subsidiary of Occidental Petroleum Corporation has delivered, to the Government of Ecuador, its written defense to the allegations. Upon review, the Government of Ecuador may decide whether there are grounds for termination of the Participation Contract.

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

4. DIVESTITURES

Total proceeds received on sale of assets and investments was $2,523 million (2004 - $1,500 million) as described below:

Upstream

In 2005, the Company has completed the disposition of mature conventional oil and natural gas assets for proceeds of $471 million (2004 - $1,430 million).

In May, the Company completed the sale of its Gulf of Mexico assets for approximately $2.1 billion resulting in net proceeds of approximately $1.5 billion after deducting $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.

Other

On December 15, 2004, EnCana sold its 25 percent limited partnership interest in Kingston CoGen Limited Partnership for net cash consideration of $25 million, recording a gain on sale of $28 million.

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

5. INTEREST, NET

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2005	2004	2005	2004
Interest Expense - Long-Term Debt	$ 107	$ 108	$ 417	$ 385
Early Retirement of Long-Term Debt	-	(5)	121	(16)
Interest Expense - Other	6	16	18	42
Interest Income	(9)	(5)	(32)	(13)
	$ 104	$ 114	$ 524	$ 398

6. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2005	2004	2005	2004
Unrealized Foreign Exchange Loss (Gain) on Translation of U.S. Dollar Debt Issued in Canada	$ 27	$ (163)	$ (113)	$ (285)
Other Foreign Exchange Loss (Gain)	10	(36)	89	(127)
	$ 37	$ (199)	$ (24)	$ (412)

7. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2005	2004	2005	2004
Current				
Canada	$ 205	$ 86	$ 493	$ 586
United States	(25)	(30)	719	(12)
Other	(2)	(3)	(8)	(15)

Total Current Tax 178 53 1,204 559

Future 717 422 56 182
Future Tax Rate Reductions - - - (109)

Total Future Tax 717 422 56 73

$ 895 $ 475 $ 1,260 $ 632

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

Three Months Twelve Months
Ended Ended
December 31, December 31,

2005 2004 2005 2004

Net Earnings Before Income Tax $ 2,764 $ 1,530 $ 4,089 $ 2,725
Canadian Statutory Rate 37.9% 39.1% 37.9% 39.1%

Expected Income Tax 1,048 599 1,550 1,066

Effect on Taxes Resulting from:
Non-deductible Canadian crown
payments 68 38 207 192
Canadian resource allowance (61) (59) (202) (246)
Canadian resource allowance
on unrealized risk management
losses (26) (37) - (10)
Statutory and other
rate differences (124) (3) (235) (50)
Effect of tax rate changes - - - (109)
Non-taxable capital (gains)
losses 3 (50) (24) (91)
Previously unrecognized capital - 7 - 17
Tax basis retained on
dispositions - 1 (68) (169)
Large corporations tax 1 11 25 24
Other (14) (32) 7 8

$ 895 $ 475 $ 1,260 $ 632

Effective Tax Rate 32.4% 31.0% 30.8% 23.2%

----

8. LONG-TERM DEBT

As at As at
December 31, December 31,
2005 2004

Canadian Dollar Denominated Debt
Revolving credit and term loan borrowings $ 1,425 $ 1,515
Unsecured notes 793 1,309

2,218 2,824

U.S. Dollar Denominated Debt
Revolving credit and term loan borrowings - 399
Unsecured notes and debentures 4,494 4,641

4,494 5,040

Increase in Value of Debt Acquired(*) 64 66
Current Portion of Long-Term Debt (73) (188)

$ 6,703 $ 7,742

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

9. 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 As at
December 31, December 31,
2005 2004

Asset Retirement Obligation, Beginning of Year $ 611 $ 383
Liabilities Incurred 77 98
Liabilities Settled (42) (16)
Liabilities Disposed (23) (35)
Change in Estimated Future Cash Flows 135 124
Accretion Expense 37 22
Other 21 35

Asset Retirement Obligation, End of Year $ 816 $ 611

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10. SHARE CAPITAL

December 31, December 31,
2005 2004

(millions) Number Amount Number Amount

Common Shares Outstanding,
Beginning of Year 900.6 $ 5,299 921.2 $ 5,305
Common Shares Issued under
Option Plans 15.0 294 19.4 281
Common Shares Repurchased (60.7) (462) (40.0) (287)

Common Shares Outstanding,
End of Year 854.9 $ 5,131 900.6 $ 5,299

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

Normal Course Issuer Bid

To December 31, 2005, the Company purchased 60,757,198 Common Shares for total consideration of approximately $2,114 million. Of the amount paid, $462 million was charged to Share capital, $10 million was charged to Paid in surplus and $1,642 million was charged to Retained earnings. Included in the above are 5.5 million Common Shares which have been purchased by an EnCana Employee Benefit Plan Trust and held for issuance upon vesting of units under EnCana's Performance Share Unit plan (see Note 11).

EnCana has obtained regulatory approval each year under Canadian securities laws to purchase Common Shares under four consecutive Normal Course Issuer Bids ("Bids") which commenced in October 2002 and may continue until October 30, 2006. EnCana is entitled to purchase for, cancellation, up to approximately 85.6 million Common Shares under the renewed Bid which commenced on October 31, 2005 and will terminate no later than October 30, 2006. During January 2006, EnCana purchased approximately 6.8 million Common Shares under the current Bid for total consideration of $314 million. Under the prior Bid which commenced October 29, 2004 and expired October 28, 2005, EnCana purchased approximately 84.2 million Common Shares.

Stock Options

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

The following tables summarize the information about options to purchase Common Shares that do not have Tandem Share Appreciation Rights ("TSAR's") attached to them at December 31, 2005. Information related to TSAR's is included in Note 11.

	Stock Options (millions)	Weighted Average Exercise Price (C$)
Outstanding, Beginning of Year	36.2	23.15
Exercised	(14.9)	22.90
Forfeited	(0.6)	21.71
Outstanding, End of Year	20.7	23.36
Exercisable, End of Year	16.8	23.21

	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$)
10.50 to 22.99	1.7	2.3	15.74	1.7	15.60
23.00 to 23.49	1.3	0.7	23.17	1.1	23.16
23.50 to 23.99	6.9	2.3	23.89	3.6	23.88
24.00 to					

24.49	10.2	1.2	24.18	10.1	24.18
24.50 to 25.99	0.6	2.6	25.23	0.3	25.21
	20.7	1.7	23.36	16.8	23.21

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 Tandem Share Appreciation Right attached. Compensation expense has not been recorded in the Consolidated Statement of Earnings related to stock options granted prior to 2003. If the Company had applied the fair-value method to options granted prior to 2003, pro forma Net Earnings and Net Earnings per Common Share for the three months ended December 31, 2005 would be unchanged (three months ended 2004 - $2,570 million; $2.80 per common share - basic; $2.76 per common share - diluted). Pro forma Net Earnings and Net Earnings per Common Share for the twelve months ended December 31, 2005 would be unchanged (2004 - $3,476 million; $3.77 per common share - basic; $3.71 per common share - diluted).

11. COMPENSATION PLANS

The tables below outline certain information related to EnCana's compensation plans at December 31, 2005. Additional information is contained in Note 15 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2004.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2005	2004	2005	2004
Current Service Cost	$ 6	$ 2	$ 11	$ 6
Interest Cost	6	5	16	14
Expected Return on Plan Assets	(5)	(4)	(14)	(12)
Amortization of Net Actuarial Loss	3	-	5	4
Amortization of Transitional Obligation	(1)	-	(2)	(2)
Amortization of Past Service Cost	1	1	2	2
Expense for Defined Contribution Plan	6	9	22	19
Net Benefit Plan Expense	$ 16	$ 13	$ 40	$ 31

For the year ended December 31, 2005, contributions to the defined benefit pension plans were made totaling $9 million as approved by the Board of Directors, and Management expects to contribute a similar amount in 2006.

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

The following table summarizes the information about SAR's at December 31, 2005:

Weighted
Average

	Outstanding SAR's	Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	930,510	18.31
Exercised	(682,241)	16.55
Forfeited	(1,530)	23.14
Outstanding, End of Year	246,739	23.13
Exercisable, End of Year	246,739	23.13
U.S. Dollar Denominated (US$)		
Outstanding, Beginning of Year	771,860	14.40
Exercised	(452,349)	14.45
Outstanding, End of Year	319,511	14.33
Exercisable, End of Year	319,511	14.33

For the year ended December 31, 2005, EnCana recorded compensation costs of $17 million related to the outstanding SAR's (2004 - $17 million).

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

The following table summarizes the information about Tandem SAR's at December 31, 2005:

	Outstanding TSAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	1,735,000	27.77
Granted	7,581,412	40.14
Exercised - SAR's	(151,610)	27.51
Exercised - Options	(104,735)	27.60
Forfeited	(656,100)	34.44
Outstanding, End of Year	8,403,967	38.41
Exercisable, End of Year	229,705	28.00

For the year ended December 31, 2005, EnCana recorded compensation costs of $60 million related to the outstanding TSAR's (2004 - $3 million).

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

The following table summarizes the information about DSU's at December 31, 2005:

	Outstanding DSU's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	750,612	24.81
Granted, Directors	80,765	43.75

Units, in Lieu of Dividends 5,184 52.34

Outstanding, End of Year 836,561 26.81

Exercisable, End of Year 836,561 26.81

For the year ended December 31, 2005, EnCana recorded compensation costs of $16 million related to the outstanding DSU's (2004 - $10 million).

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

The following table summarizes the information about PSU's at December 31, 2005:

Weighted
Average
Outstanding Grant
PSU's Price

Canadian Dollar Denominated (C$)
Outstanding, Beginning of Year 3,294,206 26.71
Granted 1,734,089 38.13
Forfeited (323,947) 30.48

Outstanding, End of Year 4,704,348 30.65

U.S. Dollar Denominated (US$)
Outstanding, Beginning of Year 449,230 20.56
Granted 390,171 30.92
Forfeited (99,752) 26.50

Outstanding, End of Year 739,649 25.22

For the year ended December 31, 2005, EnCana recorded compensation costs of $91 million related to the outstanding PSU's (2004 - $25 million).

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

12. PER SHARE AMOUNTS

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

Twelve Months
Three Months Ended Ended

September
March 31, June 30, 30, December 31, December 31,

(millions) 2005 2005 2005 2005 2004 2005 2004

Weighted
Average
Common
Shares
Outstanding
- Basic 891.8 872.0 855.1 854.4 917.6 868.3 920.8
Effect of

Dilutive
Securities 17.2 19.9 20.7 18.1 12.2 20.9 15.2

Weighted
Average
Common
Shares
Outstanding
- Diluted 909.0 891.9 875.8 872.5 929.8 889.2 936.0

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

13. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

Realized and Unrealized (Loss) Gain on Risk Management Activities

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

Realized Gain (Loss)

	Q1	Q2	Q3	Q4	YTD
Revenues, Net of Royalties	$ (19)	$ (114)	$ (196)	$ (355)	$ (684)
Operating Expenses and Other	5	5	7	14	31
Loss on Risk Management - Continuing Operations	(14)	(109)	(189)	(341)	(653)
Loss on Risk Management - Discontinued Operations	(24)	(32)	(55)	(15)	(126)
	$ (38)	$ (141)	$ (244)	$ (356)	$ (779)

Unrealized Gain (Loss)

	Q1	Q2	Q3	Q4	YTD
Revenues, Net of Royalties	$ (962)	$ 315	$ (810)	$ 991	$ (466)
Operating Expenses and Other	3	(1)	1	(6)	(3)
(Loss) Gain on Risk Management - Continuing Operations	(959)	314	(809)	985	(469)
(Loss) Gain on Risk Management - Discontinued Operations	(30)	31	(90)	139	50
	$ (989)	$ 345	$ (899)	$ 1,124	$ (419)

Amounts Recognized on Transition

As discussed in Note 2 to the annual audited Consolidated Financial

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

At December 31, 2005, a net unrealized gain remains to be recognized over the next three years as follows:

	Unrealized Gain
2006	$ 24
2007	15
2008	1
Total to be recognized	$ 40

Fair Value of Outstanding Risk Management Positions

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2005 to December 31, 2005:

	Transition Amount	Fair Market Value	Total Unrealized Gain (Loss)
Fair Value of Contracts and Premiums Paid, Beginning of Year	$ (72)	$ (189)	$ -
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts entered into During 2005	-	(1,230)	(1,230)
Fair Value of Contracts in Place at Transition Expired During 2005	32	-	32
Fair Value of Contracts Realized During 2005	-	779	779
Fair Value of Contracts Outstanding	$ (40)	$ (640)	$ (419)
Unamortized Premiums Paid on Collars and Options		316	
Fair Value of Contracts and Premiums Paid, End of Year		$ (324)	
Amounts Allocated to Continuing Operations	$ (40)	$ (304)	$ (469)
Amounts Allocated to Discontinued Operations	-	(20)	50
	$ (40)	$ (324)	$ (419)

At December 31, 2005, the remaining net deferred amounts recognized on transition and the risk management amounts are recorded in the Consolidated Balance Sheet as follows:

	As at December 31, 2005
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	$ 1
Investments and other assets	1
Accounts payable and accrued liabilities	25
Other liabilities	17
Net Deferred Gain - Continuing Operations	$ 40
Risk Management	
Current asset	$ 495
Long-term asset	530
Current liability	1,227
Long-term liability	102
Net Risk Management Liability - Continuing Operations	(304)
Net Risk Management Liability - Discontinued Operations	(20)
	$ (324)

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

	As at December 31, 2005
Commodity Price Risk	
Natural gas	$ (247)
Crude oil	(66)
Credit Derivatives	(1)
Interest Rate Risk	10
Total Fair Value Positions - Continuing Operations	(304)
Total Fair Value Positions - Discontinued Operations	(20)
	$ (324)

Information with respect to power and interest rate risk contracts in place at December 31, 2004 is disclosed in Note 16 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at December 31, 2005.

Natural Gas

At December 31, 2005, the Company's gas risk management activities from financial contracts had an unrealized loss of $(500) million and a fair market value position of $(267) million. The contracts were as follows:

Notional Fair
Volumes Market
(MMcf/d) Term Average Price Value

Sales Contracts
Fixed Price Contracts

NYMEX Fixed Price 525 2006 5.65 US$/Mcf $ (954)
Colorado Interstate
Gas (CIG) 100 2006 4.44 US$/Mcf (151)
Houston Ship
Channel (HSC) 90 2006 5.08 US$/Mcf (146)
Other 81 2006 4.58 US$/Mcf (126)

NYMEX Fixed Price 240 2007 7.76 US$/Mcf (203)

Collars and Other Options
Purchased NYMEX Put
Options 2,602 2006 7.76 US$/Mcf (73)

Purchased NYMEX Put
Options 240 2007 6.00 US$/Mcf (5)

Basis Contracts
Fixed NYMEX to
AECO Basis 799 2006 (0.69) US$/Mcf 217
Fixed NYMEX to
Rockies Basis 324 2006 (0.58) US$/Mcf 162
Fixed NYMEX to
CIG Basis 301 2006 (0.83) US$/Mcf 133
Other 182 2006 (0.36) US$/Mcf 52

Fixed NYMEX to
AECO Basis 735 2007 (0.71) US$/Mcf 101
Fixed NYMEX to
Rockies Basis 538 2007 (0.65) US$/Mcf 232
Fixed NYMEX to
CIG Basis 390 2007 (0.76) US$/Mcf 164
Fixed Rockies to
CIG Basis 12 2007 (0.10) US$/Mcf -

Fixed NYMEX to
AECO Basis 191 2008 (0.78) US$/Mcf 12
Fixed NYMEX to
Rockies Basis 162 2008 (0.59) US$/Mcf 52
Fixed NYMEX to 2008-
CIG Basis 40 2009 (0.68) US$/Mcf 23

Purchase Contracts
Fixed Price Contracts
Waha Purchase 23 2006 5.32 US$/Mcf 33

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(477)
Other Financial
Positions(*) (23)

Total Unrealized Loss
on Financial Contracts (500)
Unamortized Premiums
Paid on Options 233

Total Fair Value Positions $ (267)

Total Fair Value Positions -
Continuing Operations (247)
Total Fair Value Positions -
Discontinued Operations (20)

Total Fair Value Positions $ (267)

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

Crude Oil

At December 31, 2005, the Company's oil risk management activities from financial contracts had an unrealized loss of $(149) million and a fair market value position of $(66) million. The contracts were as follows:

Notional Average Fair
Volumes Price Market
(bbls/d) Term (US$/bbl) Value

Fixed WTI NYMEX Price 15,000 2006 34.56 $ (153)
Unwind WTI NYMEX Fixed Price (1,300) 2006 52.75 5
Purchased WTI NYMEX Put Options 57,000 2006 50.00 (10)
Purchased WTI NYMEX Call Options (13,700) 2006 61.24 14

Purchased WTI NYMEX Put Options 43,000 2007 44.44 (6)
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(150)
Other Financial Positions(*) 1

Total Unrealized Loss on
Financial Contracts (149)
Unamortized Premiums Paid
on Options 83

Total Fair Value Positions $ (66)

Total Fair Value Positions -
Continuing Operations $ (66)
Total Fair Value Positions -
Discontinued Operations -

$ (66)

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

14. 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

California

As disclosed previously, in July 2003, the Company's indirect wholly owned U.S. marketing subsidiary, WD Energy Services Inc. ("WD"), concluded a settlement with the U.S. Commodity Futures Trading Commission ("CFTC") of a previously disclosed CFTC investigation whereby WD agreed to pay a civil monetary penalty in the amount of $20 million without admitting or denying the findings in the CFTC's order.

EnCana Corporation and WD are defendants in a lawsuit filed by E. & J. Gallo Winery in the United States District Court in California, further described below. The Gallo lawsuit claims damages in excess of $30 million. California law allows for the possibility that the amount of damages assessed could be tripled.

Along with other energy companies, EnCana Corporation and WD are defendants in several other lawsuits relating to sales of natural gas in California from 1999 to 2002 (some of which are class actions and some of which are brought by individual parties on their own behalf). As is customary, these lawsuits do not specify the precise amount of damages claimed. The Gallo and other California lawsuits contain allegations that the defendants engaged in a conspiracy with unnamed competitors in the natural gas and derivatives market in California in violation of U.S. and California anti-trust and unfair competition laws.

In all but one of the class actions in the United States District Court and in the Gallo action, decisions dealing with the issue of whether the scope of the Federal Energy Regulatory Commission's exclusive jurisdiction over natural gas prices precludes the plaintiffs from maintaining their claims are on appeal to the United States Court of Appeals for the Ninth Circuit.

Without admitting any liability in the lawsuits, in November 2005, WD has agreed to pay $20.5 million to settle the class action lawsuits that were consolidated in San Diego Superior Court, subject to final documentation and approval by the San Diego Superior Court. The individual parties who had brought their own actions are not parties to this settlement.

New York

WD is also a defendant in a consolidated class action lawsuit filed in the United States District Court in New York. The consolidated New York lawsuit claims that the defendants' alleged manipulation of natural gas price indices affected natural gas futures and option contracts traded on the NYMEX from 2000 to 2002. EnCana Corporation was dismissed from the New York lawsuit, leaving WD and several other companies unrelated to EnCana Corporation as the remaining defendants. Without admitting any liability in the lawsuit, WD has agreed to pay a maximum of $9.1 million to settle the New York class action lawsuit, subject to final documentation and approval by the New York District Court.

Based on the aforementioned settlements, during the fourth quarter of 2005 a total of $30 million was recorded, which amount has been included in Administrative costs in the Net Earnings from Discontinued Operations. EnCana Corporation and WD intend to vigorously defend against the remaining 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.

15. RECLASSIFICATION

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

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