February 23, 2005

EnCana cash flow rises 12 percent to US$5 billion in 2004; Earnings up more than 40 percent

Annual sales increase 16 percent to 4.6 billion cubic feet equivalent of gas per day Board of Directors recommend 2-for-1 stock split

CALGARY, Feb. 23 /CNW/ - EnCana (TSX & NYSE: ECA) today reports a 12 percent increase in 2004 cash flow to US$4.98 billion, or $10.64 per common share diluted, compared to 2003. Total operating earnings in 2004 increased 41 percent to $1.98 billion, or $4.22 per common share diluted. Total operating earnings are net earnings excluding the after-tax impacts of a $1.4 billion gain on the sale of EnCana's U.K. North Sea assets, unrealized gains due to foreign exchange on US$ denominated debt issued in Canada and tax rate changes, and an unrealized mark-to-market loss. Net earnings in 2004 increased 49 percent to $3.5 billion, or $7.51 per common share diluted.

IMPORTANT NOTE: EnCana's 2004 year-end financial and operating results in this news release are reported on a total consolidated basis, unless otherwise noted. For financial statement purposes, EnCana is treating U.K. and Ecuador operations as discontinued because the U.K. operations were sold in December 2004 and EnCana plans to sell its Ecuador assets. EnCana reports in U.S. dollars and follows U.S. protocols, which report sales and reserves on an after-royalties basis. All dollar figures are U.S. dollars unless otherwise noted.

EnCana's double-digit sales growth and robust commodity prices contributed to strong increases in cash flow and operating earnings. Natural gas, oil and natural gas liquids (NGLs) sales increased 16 percent in 2004 to average 4.6 billion cubic feet equivalent (Bcfe) per day. On a per share basis, EnCana's 2004 sales increased 19 percent. Daily sales were comprised of 3.0 billion cubic feet of natural gas, up 17 percent from 2003, and approximately 260,000 barrels per day of oil and NGLs, a 13 percent increase. Operating and administrative costs in 2004 were approximately 70 cents per thousand cubic feet equivalent, which was within EnCana's guidance range.

"In 2004, our cash flow per share increased 14 percent, total operating earnings per share rose 45 percent and daily natural gas, oil and NGLs sales increased 19 percent per share. Since mid-year, we enhanced our financial strength by lowering our net debt-to-capitalization to 33 percent, well within our target range of 30 to 40 percent. At the same time, under our Normal Course Issuer Bid, we purchased about 4.3 percent of our shares for about $1 billion," said Gwyn Morgan, EnCana's President & Chief Executive Officer.

"This outstanding 2004 performance was achieved through strong organic growth from our portfolio of North American resource plays and by directing excess cash flow from operations and proceeds from our divestitures of conventional properties to strengthening our balance sheet and returning cash to shareholders through share purchases," Morgan said.

Financial and operating highlights

	2004	Q4 - 2004
Cash flow per share diluted	$10.64, up 14%	$3.21, up 19%
Total operating earnings per share diluted	$4.22, up 45%	$1.23, up 81%

Net earnings per share diluted	$7.51, up 53%	$5.55, up 510%
Total Mcfe sales, per 1,000 shares	3,625 Mcfe, up 19%	
Natural gas reserves	10.5 Tcf, up 28% per share	
Natural gas sales	3.0 Bcf/d, up 17%	3.11 Bcf/d, up 16%
Oil and NGLs sales	260,000 bbls/d, up 13%	248,000 bbls/d, down 7%
Total Bcfe sales	4.56 Bcfe/d, up 16%	4.60 Bcfe/d, up 7%

Two-for-one share split proposed

Due to EnCana's strong share price performance in 2004 and expectations for continuing strong operating performance, the company's board of directors is recommending that shareholders approve a two-for-one split of EnCana's common shares, which is expected to encourage greater market liquidity and wider distribution among retail investors. The proposed split will be voted on at EnCana's Annual and Special Meeting on April 27, 2005 in Calgary.

Fourth quarter cash flow up 19 percent, total operating earnings up 81 percent

In the fourth quarter of 2004, EnCana's cash flow increased 19 percent to $1.49 billion, or $3.21 per common share diluted, compared to the same 2003 period. Total operating earnings increased 81 percent to $573 million compared to the same 2003 period. Net earnings increased six fold from the same period in 2003 to $2.58 billion, or $5.55 per common share diluted, which includes a $1.4 billion gain from the sale of the company's U.K. North Sea assets.

Focusing on North American resource plays

"During 2004, we sharpened our strategic focus on unconventional resources in North America - natural gas and in-situ oilsands. The acquisition of resource play focused Tom Brown, Inc. for $2.7 billion and the divestiture of our U.K. North Sea assets for $2.1 billion, along with $1.4 billion in North American conventional asset divestitures, were significant strategic milestones. In the year, we became the continent's largest natural gas producer, at more than 3 billion cubic feet per day - enough gas to meet the daily requirements of every Canadian home, office, hospital, shopping centre and commercial building," Morgan said.

Tom Brown assets performing well

Natural gas production from the former Tom Brown, Inc. assets in the U.S. has increased about 13 percent in the seven months since the acquisition. EnCana added about 209 billion cubic feet equivalent of proved reserves, net of revisions, from former Tom Brown, Inc. lands in the U.S. in 2004.

EnCana continues to move ahead with divestiture of conventional assets

EnCana is planning to sell Canadian conventional properties producing about 22,000 BOE per day. In order to enhance shareholder value, EnCana is considering a variety of options to monetize these assets, including a cash sale or the conversion of the assets into an income trust.

EnCana is also planning the sale of its portfolio of discoveries and exploration interests in the Gulf of Mexico and producing properties and pipeline interests in Ecuador. As a result, Ecuador operations have been treated as discontinued for financial reporting purposes and EnCana's corporate guidance for 2005 has been updated to reflect this change.

Proceeds from all of these divestitures are expected to be in the range of $3 billion, plus or minus.

"For 2005, we will further increase our focus on growing our long-life resource plays. And once we have completed our planned divestitures, we expect that about 80 percent of EnCana's production will be natural gas, generating about 85 percent of the company's operating cash flow," Morgan said.

North American natural gas reserves up 24 percent to 10.5 trillion cubic feet

While 2004 was a year of strong growth, the company also added to the source of its future growth. Proved reserves of North American natural gas increased 24 percent to 10.5 trillion cubic feet in 2004, adding 2.2 trillion cubic feet through the drill bit and acquiring a net 0.9 trillion cubic feet primarily through the Tom Brown, Inc. acquisition. With total net North America gas additions of 3.2 trillion cubic feet, compared to the 1.1 trillion cubic feet of production in 2004, EnCana's North America gas production replacement reached 290 percent. On February 1 and 16, 2005, the company issued more detailed results of its 2004 operations, including reserve additions, capital costs and a downward revision of 363 million barrels of bitumen reserves. All of EnCana's proved reserves estimates are prepared by independent qualified reserves evaluators.

Three years of consistent and competitive reserve addition costs

"EnCana's North American resource play exploitation programs steadily and predictably convert our huge unbooked resource potential to proved reserves. Future growth in reserves and production visibility is illustrated by the fact that our unbooked resource potential exceeds our proved reserves. Over the past three years, before the negative bitumen revision, we achieved a production replacement averaging nearly 200 percent, at an average cost of $1.42 per thousand cubic feet equivalent - a highly competitive cost during a time when increasing demand for field services and a rising Canadian dollar have fuelled inflation. In 2004, our proved reserve replacement costs were $1.40 per thousand cubic feet equivalent. With our average netback, after operating and administration costs, of $4.00 per thousand cubic feet equivalent in 2004, we've achieved a recycle ratio of 2.9 times - evidence of the strong value EnCana continues to create," said Randy Eresman, EnCana's Chief Operating Officer.

Fourth quarter natural gas sales up 16 percent, total gas and oil sales rise 7 percent despite divestitures

Fourth quarter natural gas, oil and NGLs sales averaged 4.6 Bcfe per day, up 7 percent from 4.3 Bcfe per day in the same period in 2003. Natural gas sales increased 16 percent to average 3.1 billion cubic feet per day. Oil and NGLs sales in the fourth quarter of 2004 averaged 247,600 barrels per day, down 7 percent from the same 2003 period due to the sale of conventional producing properties. EnCana drilled 958 net wells in the fourth quarter of 2004, comprised of 811 development wells and 147 exploration wells.

EnCana targets 15 percent gas sales growth in 2005

In 2005, EnCana is forecasting daily gas sales of between 3.35 billion and 3.5 billion cubic feet, which, at midpoint, is approximately a 15 percent increase from the company's 2004 daily sales from continuing operations of 2.97 billion cubic feet per day. With planned divestitures of Canadian conventional oil and gas properties, EnCana expects 2005 oil and NGLs sales from continuing operations to be between 150,000 and 170,000 barrels per day. Overall, EnCana is forecasting 2005 daily sales of between 4.25 Bcfe and 4.5 Bcfe, up about 10 percent from 2004 daily sales of 3.97 Bcfe from continuing operations. EnCana has updated its corporate guidance on its Web site, www.encana.com.

Consolidated EnCana Highlights

US$ and U.S. protocols

Financial Highlights (as at and for the period ended December 31) (US$ millions, except per share amounts)	Q4 2004	Q4 2003	% change	2004	2003	% change
Revenues, net of royalties (including discontinued operations)	4,407	2,850	+ 55	12,433	10,303	+ 21
Cash flow	1,491	1,254	+ 19	4,980	4,459	+ 12
Per share - basic	3.25	2.71	+ 20	10.82	9.41	+ 15
Per share - diluted	3.21	2.69	+ 19	10.64	9.30	+ 14

Add back:						
Total cash tax	20	(69)	- 129	579	(54)	-1,172
Pre-tax cash flow	1,511	1,185	+ 28	5,559	4,405	+ 26
Net capital investment	(662)	1,381	- 148	4,206	3,422	+ 23
Net earnings from continuing operations	1,188	447	+ 166	2,211	2,142	+ 3
Per share - basic	2.59	0.97	+ 167	4.80	4.52	+ 6
Per share - diluted	2.56	0.96	+ 167	4.72	4.47	+ 6
Net earnings	2,580	426	+ 506	3,513	2,360	+ 49
Per share - basic	5.62	0.92	+ 511	7.63	4.98	+ 53
Per share - diluted	5.55	0.91	+ 510	7.51	4.92	+ 53
Add (Deduct):						
(Gain) on sale of discontinued operations, after tax	(1,364)	-	n/a	(1,364)	(169)	n/a
Unrealized mark-to-market accounting (gain)/loss, after-tax	(512)	-	n/a	165	-	n/a
Unrealized foreign exchange (gain) on translation of U.S. dollar debt issued in Canada, after-tax	(131)	(113)	+ 16	(229)	(433)	- 47
Future tax (recovery) due to tax rate change	-	3	n/a	(109)	(359)	- 70
Total operating earnings	573	316	+ 81	1,976	1,399	+ 41
Per share - diluted	1.23	0.68	+ 81	4.22	2.92	+ 45
Common shares (millions)						
Weighted average (basic)	458.8	462.3	- 1	460.4	474.1	- 3
Weighted average (diluted)	464.9	465.9	-	468.0	479.7	- 2

Operating Highlights (for the period ended December 31) (After royalties)	Q4 2004	Q4 2003	% change	2004	2003	% change
Continuing operations						
North America Natural Gas (MMcf/d)						
Production (excluding Tom Brown, Inc.)	2,833	2,662	+ 6	2,802	2,523	+ 11
Tom Brown, Inc. production	280	-	n/a	172	-	n/a
Inventory withdrawal/ (injection)	(26)	-	n/a	(6)	30	n/a
Natural gas sales (MMcf/d)	3,087	2,662	+ 16	2,968	2,553	+ 16
North America Oil and NGLs (bbls/d)	159,470	174,471	- 9	166,417	165,895	0
Discontinued operations						
U.K. natural gas (MMcf/d)	22	20	+ 10	30	13	+ 131
U.K. oil and NGLs (bbls/d)	10,260	15,067	- 32	15,973	10,128	+ 58
Ecuador (bbls/d)	77,876	77,352	+ 1	77,993	46,521	+ 68

Syncrude (bbls/d)	-	-	-	-	7,629	-
Total discontinued operations (BOE/d)	91,803	95,752	- 4	98,966	66,445	+ 49
Total natural gas sales (MMcf/d)	3,109	2,682	+ 16	2,998	2,566	+ 17
Total oil and NGLs sales (bbls/d)	247,606	266,890	- 7	260,383	230,173	+ 13
Total sales (MMcfe/d)	4,595	4,283	+ 7	4,560	3,947	+ 16
Total sales (BOE/d)	765,773	713,890	+ 7	760,050	657,840	+ 16
Per share sales growth						+ 19

North American natural gas prices rise in 2004

North American realized field prices, excluding financial hedging, averaged $5.47 per thousand cubic feet, up 12 percent from an average of $4.87 per thousand cubic feet in 2003. Driven by continued strong demand despite the effects of a cooler summer and warmer average winter temperatures, the influence of strong oil prices and ongoing concerns about North American gas supply, the average 2004 benchmark NYMEX index gas price was $6.14 per thousand cubic feet, up 14 percent from $5.39 per thousand cubic feet in 2003. In the fourth quarter, EnCana's average realized field price, excluding financial hedging, was $6.08 per thousand cubic feet, up 35 percent from $4.49 in the same 2003 period. The average benchmark NYMEX index price was $7.11 per thousand cubic feet, an increase of 55 percent from the fourth quarter of 2003.

World oil prices strong in 2004; Canadian heavy oil price differentials widen

World oil prices rose dramatically through much of 2004 due to strength in global demand, primarily in Asia and North America and fourth quarter concerns over sufficient heating oil supply. Supply concerns were fuelled by Middle East tensions, the conflict in Iraq and, in the last half of 2004, hurricane damage to Gulf of Mexico production facilities. During 2004, the average benchmark West Texas Intermediate (WTI) crude oil price was $41.47 per barrel, up 34 percent over the 2003 average of $30.99 per barrel. OPEC increased production to satisfy demand, but new supplies were largely heavier grades and more sour blends, which contributed to a widening of the light-heavy price differential in Canada. The 2004 WTI/Bow River differential increased 60 percent to $12.82 per barrel compared to 2003; and is up more than double from more historical levels of $5.93 per barrel two years earlier in 2002. In Ecuador, the WTI/NAPO differential also widened to $14.33 per barrel, up 78 percent from $8.06 per barrel in the last four months of 2003.

In 2004, EnCana's average realized oil and NGLs price, excluding hedging, was $29.17 per barrel; including hedging, it was $21.34 per barrel. In the fourth quarter, the company's average realized oil and NGLs price, excluding hedging, was $30.74 per barrel; including hedging, it was $20.61 per barrel.

Risk management strategy

EnCana's market risk mitigation strategy is intended to help deliver greater predictability of cash flow and returns on investment. Detailed risk management positions at December 31, 2004 are presented in Note 14 to the unaudited fourth quarter consolidated financial statements. In 2004, EnCana's financial commodity and currency risk management measures resulted in after-tax cash flow being lower by approximately $700 million, comprised of

$540 million on oil hedges and $160 million on gas hedges. In the fourth quarter, financial commodity and currency risk management measures resulted in after-tax cash flow being lower by approximately $260 million, comprised of $190 million on oil hedges and $70 million on gas hedges.

Hedging impact expected to wane in 2005

2004 oil hedging losses were exacerbated by an unprecedented discount between heavy oil and benchmark WTI prices. A review of the company's hedging strategy has resulted in a preference to the use of hedging instruments which provide downside protection, but do not limit upside in a rising price environment. EnCana has purchased WTI put options with a floor price of $40 per barrel for approximately 15 percent of forecast crude oil sales for 2005. EnCana has also purchased NYMEX gas put options with a floor price of $5.46 per thousand cubic feet covering 27 percent of forecast gas sales for 2005. About 19 percent of EnCana's 2005 forecast oil sales is hedged with swaps or collars at approximately $29 per barrel. These arrangements were entered into prior to the tactical change to focus on downside protection. In order to limit the cost of possible extreme oil prices on these oil swaps, EnCana entered into call options for 2005 at an average price of $49.76 per barrel, allowing the company to participate in oil price upside above this level. About 20 percent of EnCana's 2005 forecast gas sales are hedged with swaps at an average price of $6.37 per thousand cubic feet. In addition, 1 percent of EnCana's 2005 forecast gas sales are hedged with collars with a floor price of $2.89 per thousand cubic feet and a ceiling price of $5.37 per thousand cubic feet. Five percent of EnCana's gas sales are hedged with three-way options with a floor price of $5.00 per thousand cubic feet and a ceiling price of $6.69 per thousand cubic feet with a call option purchased at an average price of $7.69, which will allow EnCana to participate in gas price upside above this level. The company has also entered into longer term basis hedges specifically for the purpose of protecting against high U.S. Rockies gas price basis differentials. EnCana will continue to use a variety of hedging instruments for its future hedging programs.

Corporate developments

Quarterly dividend of $0.10 per share declared

EnCana's board of directors has declared a quarterly dividend of $0.10 per share payable on March 31, 2005 to common shareholders of record as of March 15, 2005.

Shareholders to vote regarding two-for-one share split

At the Annual and Special meeting of EnCana's shareholders on April 27, 2005, EnCana's shareholders will be asked to approve the split of EnCana's outstanding common shares on a two-for-one basis. In addition to shareholder approval, the stock split is subject to the receipt of all required regulatory approvals.

If approved by shareholders, and subject to regulatory approvals, each shareholder will receive one additional common share for each common share he or she holds on the record date for the stock split of May 12, 2005. Pursuant to the rules of the Toronto Stock Exchange, EnCana's common shares will commence trading on a subdivided basis at the opening of business on May 10, 2005, which is the second trading day preceding the record date. Also on May 10, 2005, EnCana's common shares listed on the New York Stock Exchange (NYSE) will commence trading with rights entitling holders to an additional common share for each common share held upon the commencement of trading of the common shares on a subdivided basis on the NYSE. The trading of the common shares on a subdivided basis on the NYSE will occur one day after the delivery of share certificates to registered holders of EnCana's common shares. It is anticipated that share certificates representing the additional common shares resulting from the stock split will be mailed to registered common shareholders on or about May 20, 2005.

Normal Course Issuer Bid increased to permit purchase of 10 percent of EnCana's public float

On February 4, the Toronto Stock Exchange (TSX) approved an amendment to EnCana's Normal Course Issuer Bid (Bid), first approved in October 2004, increasing the number of common shares available for purchase from 5 percent of the issued and outstanding shares on October 22, 2004 to 10 percent of the public float on October 22, 2004. There were approximately 462 million common shares outstanding on October 22, 2004. The company estimates that 10 percent of the public float on that date is equal to approximately 46.1 million common shares.

EnCana's planned divestitures of conventional assets in 2005 are expected to bring in substantial funds and the company's capital program is expected to be funded by cash flow. EnCana believes the Bid amendment will provide the opportunity to increase net asset value per share through share purchases.

To date under its current Bid, EnCana has purchased approximately 21.2 million common shares, representing approximately 4.6 percent of the company's outstanding common shares on October 22, 2004, at an average price of US$54.56 per common share. As at January 31, 2005, EnCana had approximately 446 million common shares outstanding. In 2004, approximately 10 million shares were issued upon the exercise of options by employees as part of the company's long-term incentive program. Under the amended Bid, the company is entitled to purchase for cancellation up to an additional 25 million common shares through the expiry of the amended Bid on October 28, 2005. Purchases will be made on the open market through the facilities of TSX in accordance with its policies, and may also be made through the facilities of the NYSE in accordance with its rules. The price to be paid will be the market price at the time of acquisition.

Financial strength

EnCana targets a net debt-to-capitalization ratio between 30 and 40 percent. At December 31, 2004, 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 1.4 times.

Capital investment

EnCana has published supplemental information detailing 2004 capital investment on its Web site, www.encana.com.

CONFERENCE CALL TODAY

EnCana Corporation will host a conference call today, Wednesday, February 23, 2005 starting at 11 a.m., Mountain Time (1 p.m. Eastern Time), to discuss EnCana's fourth quarter and year-end 2004 financial and operating results.

To participate, please dial (913) 981-5523 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 5 p.m. MT on February 23 until midnight March 1, 2005 by dialling (888) 203-1112 or (719) 457-0820 and entering access code 4871829.

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

NOTE 1: EnCana financial results in U.S. dollars and operating results according to U.S. protocols

Starting with year-end 2003, EnCana is reporting its financial results in U.S. dollars and its reserves and production according to U.S. protocols in order to facilitate a more direct comparison to other North American upstream oil and natural gas exploration and development companies. Reserves and production are reported on an after-royalties basis. There is no change to the physical volumes produced and sold or to the actual reserves as a result of adopting U.S. protocols. However, readers should note that the change results in a general lowering of reported numbers for EnCana's sales volumes and impacts the percentage changes year over year. For example, under previous Canadian protocols, if EnCana produced and sold 100 barrels of oil at the well head, it reported sales of 100 barrels. Under the new U.S. protocol, royalties paid to the Crown, state or mineral rights owners are deducted before sales volumes are reported. For example, under U.S. protocols, if EnCana produced and sold 100 barrels and the oil was subject to a 20 percent royalty, EnCana would report sales of 80 barrels of oil.

NOTE 2: Non-GAAP measures

This news release contains references to cash flow and total operating earnings. 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. 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$35 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 low geological and commercial development risk, low average decline rates and very long producing lives. 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.

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 equivalency at the well head.

Production replacement is calculated by dividing reserve replacement by production in the same period. Reserve replacement is calculated by summing the total proved reserves added over a given period, in this case calendar year 2004, through one or more of revisions, improved recovery, extensions, discoveries and acquisitions net of divestitures. Reserve replacement cost is calculated by dividing total capital invested in finding, development and net acquisitions by reserve replacement in the same period. 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.

Resource potential is a term used by EnCana to refer to the estimated quantities of hydrocarbons that may be added to proved reserves over a specified period of time from a specified resource play or plays.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements within the meaning of the "safe harbour" provisions of the United States Private Securities Litigation Reform Act of 1995. Forward-looking statements in this news release include, but are not limited to: future economic and operating performance (including per share growth 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 conventional Western Canadian properties, the potential structure of such transactions and the potential monetization of such assets; planned sale of interests in the Gulf of Mexico and Ecuador; the expected proceeds from planned divestitures; 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; the anticipated steps to implement the proposed two-for-one share split and the impact of such a split; anticipated purchases pursuant to the Normal Course Issuer Bid; estimated recycle ratios; potential demand for gas; anticipated production in 2004 and beyond; anticipated drilling; potential capital expenditures and investment; potential oil, natural gas and NGLs sales in 2004 and beyond; anticipated costs; potential risks associated with drilling and references to potential exploration. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of oil and gas prices; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, natural gas and liquids from resource plays and other sources not currently classified as proved reserves; the company's ability to replace and expand oil and gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in environmental and other regulations or the interpretations of such regulations; political and economic conditions in the countries in which the company operates, including Ecuador; the risk of war, hostilities, civil insurrection and instability affecting countries in which the company operates and terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana. Although EnCana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive.

Furthermore, the forward-looking statements contained in this news release are made as of the date of this news release, and EnCana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

Interim Report

For the period ended December 31, 2004

EnCana Corporation

CONSOLIDATED STATEMENT OF EARNINGS (unaudited)

		December 31			
		Three Months Ended		Year Ended	
(US$ millions, except per share amounts)		2004	2003	2004	2003
REVENUES, NET OF ROYALTIES	(Note 4)				
Upstream		$ 2,003	$ 1,462	$ 7,256	$ 5,797
Midstream & Market Optimization		1,543	1,177	4,749	3,887
Corporate		662	-	(195)	2
		4,208	2,639	11,810	9,686
EXPENSES	(Note 4)				
Production and mineral taxes		95	50	311	164
Transportation and selling		109	143	499	484
Operating		390	296	1,350	1,196
Purchased product		1,367	1,049	4,276	3,455
Depreciation, depletion and amortization		641	632	2,402	1,989
Administrative		61	52	197	173
Interest, net		113	81	397	283
Accretion of asset retirement obligation	(Note 10)	6	3	22	17
Foreign exchange gain	(Note 7)	(204)	(161)	(417)	(598)
Stock-based compensation		3	6	17	18
Gain on dispositions	(Note 6)	(78)	(1)	(113)	(1)
		2,503	2,150	8,941	7,180
NET EARNINGS BEFORE INCOME TAX		1,705	489	2,869	2,506
Income tax expense	(Note 8)	517	42	658	364
NET EARNINGS FROM CONTINUING OPERATIONS		1,188	447	2,211	2,142
NET EARNINGS (LOSS) FROM DISCONTINUED OPERATIONS	(Note 5)	1,392	(21)	1,302	218

NET EARNINGS		$ 2,580	$ 426	$ 3,513	$ 2,360

NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	(Note 13)				
Basic		$ 2.59	$ 0.97	$ 4.80	$ 4.52
Diluted		$ 2.56	$ 0.96	$ 4.72	$ 4.47

NET EARNINGS PER COMMON SHARE	(Note 13)				
Basic		$ 5.62	$ 0.92	$ 7.63	$ 4.98
Diluted		$ 5.55	$ 0.91	$ 7.51	$ 4.92

CONSOLIDATED STATEMENT OF RETAINED EARNINGS
(unaudited)

		Year Ended December 31	
(US$ millions)		2004	2003
RETAINED EARNINGS, BEGINNING OF YEAR		$ 5,276	$ 3,523
Net Earnings		3,513	2,360
Dividends on Common Shares		(183)	(139)
Charges for Normal Course Issuer Bid	(Note 11)	(671)	(468)
RETAINED EARNINGS, END OF YEAR		$ 7,935	$ 5,276

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET (unaudited)

(US$ millions)		As at December 31, 2004	As at December 31, 2003
ASSETS			
Current Assets			
Cash and cash equivalents		$ 602	$ 113
Accounts receivable and accrued revenues		1,898	1,165
Risk management	(Note 14)	336	-
Inventories		513	557
Assets of discontinued operations	(Note 5)	156	781
		3,505	2,616
Property, Plant and Equipment, net	(Note 4)	23,140	17,770
Investments and Other Assets		334	268
Risk Management	(Note 14)	87	-
Assets of Discontinued Operations	(Note 5)	1,623	1,545
Goodwill		2,524	1,911
	(Note 4)	$ 31,213	$ 24,110
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 1,879	$ 1,348
Income tax payable		359	32
Risk management	(Note 14)	241	-
Liabilities of discontinued			

operations	(Note 5)	280	405
Current portion of long-term debt	(Note 9)	188	287
		2,947	2,072
Long-Term Debt	(Note 9)	7,742	6,088
Other Liabilities		118	21
Risk Management	(Note 14)	192	-
Asset Retirement Obligation	(Note 10)	611	383
Liabilities of Discontinued Operations	(Note 5)	102	112
Future Income Taxes		5,193	4,156
		16,905	12,832
Shareholders' Equity			
Share capital	(Note 11)	5,299	5,305
Share options, net		10	55
Paid in surplus		28	18
Retained earnings		7,935	5,276
Foreign currency translation adjustment		1,036	624
		14,308	11,278
		$ 31,213	$ 24,110

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS (unaudited)

		December 31			
		Three Months Ended		Year Ended	
(US$ millions)		2004	2003	2004	2003
OPERATING ACTIVITIES					
Net earnings from continuing operations		$ 1,188	$ 447	$ 2,211	$ 2,142
Depreciation, depletion and amortization		641	632	2,402	1,989
Future income taxes	(Note 8)	461	136	91	477
Unrealized (gain) loss on risk management	(Note 14)	(662)	-	190	-
Unrealized foreign exchange gain	(Note 7)	(163)	(141)	(285)	(545)
Accretion of asset retirement obligation	(Note 10)	6	3	22	17
Gain on dispositions	(Note 6)	(78)	(1)	(113)	(1)
Other		36	27	87	56
Cash flow from continuing operations		1,429	1,103	4,605	4,135
Cash flow from discontinued operations		62	151	375	324
Cash flow		1,491	1,254	4,980	4,459
Net change in other assets and liabilities		(105)	(2)	(176)	(84)
Net change in non-cash working capital from continuing operations		1,857	(416)	1,455	(568)

Net change in non-cash working capital from discontinued operations		(1,955)	96	(1,668)	497
		1,288	932	4,591	4,304
INVESTING ACTIVITIES					
Business combination with Tom Brown, Inc.	(Note 3)	-	-	(2,335)	-
Capital expenditures	(Note 4)	(1,509)	(1,406)	(4,817)	(4,627)
Proceeds on disposal of assets	(Note 4)	72	282	1,144	301
Dispositions (acquisitions)	(Note 6)	99	-	386	(91)
Equity investments		(5)	(3)	47	(6)
Net change in investments and other		70	17	45	(15)
Net change in non-cash working capital from continuing operations		77	-	(21)	(113)
Discontinued operations		1,891	(240)	1,292	822
		695	(1,350)	(4,259)	(3,729)
FINANCING ACTIVITIES					
Net issuance of revolving long-term debt		287	26	72	288
Issuance of long-term debt		-	500	3,761	500
Repayment of long-term debt		(1,005)	-	(2,759)	(142)
Issuance of common shares	(Note 11)	97	19	281	114
Purchase of common shares	(Note 11)	(774)	(186)	(1,004)	(868)
Dividends on common shares		(46)	(36)	(183)	(139)
Other		6	(8)	(5)	(13)
Discontinued operations		-	-	-	(282)
		(1,435)	315	163	(542)
DEDUCT: FOREIGN EXCHANGE LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		6	1	6	10
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		542	(104)	489	23
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		60	217	113	90
CASH AND CASH EQUIVALENTS, END OF YEAR		$ 602	$ 113	$ 602	$ 113

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements (unaudited)

(All amounts in US$ millions unless otherwise specified)

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration 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, 2003, except as noted below. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. The interim Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2003.

2. CHANGE IN ACCOUNTING POLICIES AND PRACTICES

Consolidation of Variable Interest Entities

On November 1, 2004, the Company retroactively adopted the new Canadian Institute of Chartered Accountants' ("CICA") Accounting Guideline 15 ("AcG - 15") "Consolidation of Variable Interest Entities". The guideline defines a variable interest entity ("VIE") as a legal entity in which either the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by other parties or the equity owners lack a controlling financial interest. The guideline requires the enterprise which absorbs the majority of a VIE's expected gains or losses, the primary beneficiary, to consolidate the VIE.

There was no effect on the Company's Consolidated Financial Statements prior to the adoption of the guideline on November 1, 2004. Subsequent to November 1, 2004, the Company became the primary beneficiary of a VIE. At December 31, 2004, the Company has consolidated the results for this entity as described in Note 4.

Hedging Relationships

On January 1, 2004, the Company adopted the amendments made to the CICA Accounting Guideline 13 ("AcG - 13") "Hedging Relationships", and Emerging Issues Committee Abstract 128 ("EIC 28") "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". Derivative instruments that do not qualify as a hedge under AcG - 13, or are not designated as a hedge, are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. The Company elected not to designate any of its risk management activities in place at December 31, 2003 as accounting hedges under AcG - 13 and, accordingly, has accounted for all these non-hedging derivatives using the mark-to-market accounting method. The impact on the Company's Consolidated Financial Statements at January 1, 2004 resulted in the recognition of risk management assets with a fair value of $145 million, risk management liabilities with a fair value of $380 million and a net deferred loss of $235 million which will be recognized into net earnings as the contracts expire. At December 31, 2004, a net unrealized gain remains to be recognized over the next four years as follows:

	Unrealized Gain
2005	
Quarter 1	$ -
Quarter 2	14
Quarter 3	9
Quarter 4	9
Total to be recognized in 2005	$ 32
2006	$ 24
2007	15
2008	1

Total to be recognized in 2006 through to 2008	$ 40
Total to be recognized	$ 72
Total to be recognized - Continuing Operations	$ 73
Total to be recognized - Discontinued Operations	(1)
	$ 72

At December 31, 2004, the remaining deferred gains related to continuing operations totalled $73 million of which $11 million was recorded in Accounts receivable and accrued revenues, $4 million in Investments and other assets, $44 million in Accounts payable and accrued liabilities and $44 million in Other liabilities.

3. BUSINESS COMBINATION WITH TOM BROWN, INC.

In May 2004, the Company completed the tender offer for the common shares of Tom Brown, Inc., a Denver based independent energy company, for total cash consideration of $2.3 billion plus the assumption of $406 million of long-term debt.

The business combination has been accounted for using the purchase method with the results of operations of Tom Brown, Inc. included in the Consolidated Financial Statements from the date of acquisition.

The calculation of the purchase price and the allocation to assets and liabilities is shown below.

Calculation of Purchase Price	
Cash paid for common shares of Tom Brown, Inc.	$ 2,341
Transaction costs	13
Total purchase price	$ 2,354
Plus: Fair value of liabilities assumed	
Current liabilities	224
Long-term debt	406
Other non-current liabilities	39
Future income taxes	774
Total Purchase Price and Liabilities Assumed	$ 3,797
Fair Value of Assets Acquired	
Current assets (including cash acquired of $19 million)	$ 425
Property, plant and equipment, net	2,890
Other non-current assets	9
Goodwill	473
Total Fair Value of Assets Acquired	$ 3,797

Included in current assets as Assets held for sale is $263 million related to the value of certain oil and gas properties located in west Texas and New Mexico and the assets of Sauer Drilling Company, a subsidiary of Tom Brown, Inc., for which the Company has entered into purchase and sale agreements. These sales were completed on July 30, 2004.

4. 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. International new venture exploration is mainly focused on opportunities in Africa, South America, the Middle East and Greenland.

- Midstream & Market Optimization is conducted by the Midstream & Marketing division. Midstream includes natural gas storage, natural gas liquids processing and power generation. The Marketing groups' primary responsibility is the sale of the Company's proprietary production. The results are included in the Upstream segment. Correspondingly, the Marketing groups also undertake market optimization activities which comprise third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Midstream & Market Optimization segment.
- Corporate includes unrealized gains or losses recorded on derivative instruments. Once amounts are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates.

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

Operations that have been discontinued are disclosed in Note 5.

Results of Continuing Operations

(For the three months ended December 31)

	Upstream		Midstream & Market Optimization	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 2,003	$ 1,462	$ 1,543	$ 1,177
Expenses				
Production and mineral taxes	95	50	-	-
Transportation and selling	102	132	7	11
Operating	286	213	101	83
Purchased product	-	-	1,367	1,049
Depreciation, depletion and amortization	614	596	10	27
Segment Income	$ 906	$ 471	$ 58	$ 7

	Corporate		Consolidated	
	2004	2003	2004	2003
Revenues, Net of Royalties(x)	$ 662	$ -	$ 4,208	$ 2,639
Expenses				
Production and mineral taxes	-	-	95	50
Transportation and selling	-	-	109	143
Operating	3	-	390	296
Purchased product	-	-	1,367	1,049
Depreciation, depletion and amortization	17	9	641	632
Segment Income	$ 642	$ (9)	1,606	469
Administrative			61	52
Interest, net			113	81

Accretion of asset retirement obligation	6	3
Foreign exchange gain	(204)	(161)
Stock-based compensation	3	6
Gain on dispositions	(78)	(1)
	(99)	(20)
Net Earnings Before Income Tax	1,705	489
Income tax expense	517	42
Net Earnings From Continuing Operations	$ 1,188	$ 447

(x) Corporate revenue primarily reflects unrealized gains or losses recorded on derivative instruments. See also Note 14.

Upstream

	Canada		United States	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 1,313	$ 1,131	$ 628	$ 298
Expenses				
Production and mineral taxes	26	23	69	27
Transportation and selling	75	102	27	30
Operating	180	160	39	17
Depreciation, depletion and amortization	455	422	145	82
Segment Income	$ 577	$ 424	$ 348	$ 142

	Other		Total Upstream	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 62	$ 33	$ 2,003	$ 1,462
Expenses				
Production and mineral taxes	-	-	95	50
Transportation and selling	-	-	102	132
Operating	67	36	286	213
Depreciation, depletion and amortization	14	92	614	596
Segment Income	$ (19)	$ (95)	$ 906	$ 471

Midstream & Market Optimization

	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2004	2003	2004	2003	2004	2003
Revenues	$ 569	$ 438	$ 974	$ 739	$ 1,543	$ 1,177
Expenses						
Transportation and selling	-	-	7	11	7	11
Operating	87	73	14	10	101	83
Purchased product	416	339	951	710	1,367	1,049
Depreciation, depletion and amortization	10	22	-	5	10	27

Segment Income	$ 56	$ 4	$ 2	$ 3	$ 58	$ 7

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

Produced Gas

	Produced Gas					
	Canada		United States		Total	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 1,041	$ 862	$ 578	$ 275	$ 1,619	$ 1,137
Expenses						
Production and mineral taxes	19	19	63	24	82	43
Transportation and selling	74	81	27	30	101	111
Operating	103	84	39	17	142	101
Operating Cash Flow	$ 845	$ 678	$ 449	$ 204	$ 1,294	$ 882

Oil & NGLs

	Oil & NGLs					
	Canada		United States		Total	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 272	$ 269	$ 50	$ 23	$ 322	$ 292
Expenses						
Production and mineral taxes	7	4	6	3	13	7
Transportation and selling	1	21	-	-	1	21
Operating	77	76	-	-	77	76
Operating Cash Flow	$ 187	$ 168	$ 44	$ 20	$ 231	$ 188

Other & Total Upstream

	Other		Total Upstream	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 62	$ 33	$ 2,003	$ 1,462
Expenses				
Production and mineral taxes	-	-	95	50
Transportation and selling	-	-	102	132
Operating	67	36	286	213
Operating Cash Flow	$ (5)	$ (3)	$ 1,520	$ 1,067

Results of Continuing Operations (For the year ended December 31)

	Upstream	Midstream & Market Optimization

	2004	2003	2004	2003
Revenues, Net of Royalties	$ 7,256	$ 5,797	$ 4,749	$ 3,887
Expenses				
Production and mineral taxes	311	164	-	-
Transportation and selling	472	429	27	55
Operating	1,026	872	325	324
Purchased product	-	-	4,276	3,455
Depreciation, depletion and amortization	2,271	1,900	70	48
Segment Income	$ 3,176	$ 2,432	$ 51	$ 5

	Corporate		Consolidated	
	2004	2003	2004	2003
Revenues, Net of Royalties(x)	$ (195)	$ 2	$ 11,810	$ 9,686
Expenses				
Production and mineral taxes	-	-	311	164
Transportation and selling	-	-	499	484
Operating	(1)	-	1,350	1,196
Purchased product	-	-	4,276	3,455
Depreciation, depletion and amortization	61	41	2,402	1,989
Segment Income	$ (255)	$ (39)	2,972	2,398
Administrative			197	173
Interest, net			397	283
Accretion of asset retirement obligation			22	17
Foreign exchange gain			(417)	(598)
Stock-based compensation			17	18
Gain on dispositions			(113)	(1)
			103	(108)
Net Earnings Before Income Tax			2,869	2,506
Income tax expense			658	364
Net Earnings From Continuing Operations			$ 2,211	$ 2,142

(x) Corporate revenue primarily reflects unrealized gains or losses recorded on derivative instruments. See also Note 14.

Upstream	Canada		United States	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 5,083	$ 4,474	$ 1,941	$ 1,143
Expenses				
Production and mineral taxes	87	56	224	108
Transportation and selling	352	343	120	86
Operating	685	642	119	60
Depreciation, depletion and amortization	1,751	1,511	475	293
Segment Income	$ 2,208	$ 1,922	$ 1,003	$ 596

Transportation and selling for the United States includes a one-time payment of $21 million made in Q2 2004 to terminate a long-term physical delivery contract.

	Other		Total Upstream	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 232	$ 180	$ 7,256	$ 5,797
Expenses				
Production and mineral taxes	-	-	311	164
Transportation and selling	-	-	472	429
Operating	222	170	1,026	872
Depreciation, depletion and amortization	45	96	2,271	1,900
Segment Income	$ (35)	$ (86)	$ 3,176	$ 2,432

Midstream & Market Optimization	Midstream		Market Optimization		Total Midstream & Market Optimization	
	2004	2003	2004	2003	2004	2003
Revenues	$ 1,450	$ 1,084	$ 3,299	$ 2,803	$ 4,749	$ 3,887
Expenses						
Transportation and selling	-	-	27	55	27	55
Operating	279	261	46	63	325	324
Purchased product	1,071	762	3,205	2,693	4,276	3,455
Depreciation, depletion and amortization	68	40	2	8	70	48
Segment Income	$ 32	$ 21	$ 19	$ (16)	$ 51	$ 5

Midstream Depreciation, depletion and amortization includes a $35 million impairment charge made in Q2 2004 on the Company's interest in Oleoducto Trasandino in Argentina and Chile.

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

Produced Gas	Produced Gas					
	Canada		United States		Total	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 3,928	$ 3,396	$ 1,776	$ 1,051	$ 5,704	$ 4,447
Expenses						
Production and mineral taxes	65	52	205	101	270	153
Transportation and selling	296	274	120	86	416	360
Operating	400	342	119	60	519	402
Operating Cash Flow	$ 3,167	$ 2,728	$ 1,332	$ 804	$ 4,499	$ 3,532

Transportation and selling for the United States includes a one-time payment of $21 million made in Q2 2004 to terminate a long-term physical delivery contract.

Oil & NGLs

	Canada		United States		Total	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 1,155	$ 1,078	$ 165	$ 92	$ 1,320	$ 1,170
Expenses						
Production and mineral taxes	22	4	19	7	41	11
Transportation and selling	56	69	-	-	56	69
Operating	285	300	-	-	285	300
Operating Cash Flow	$ 792	$ 705	$ 146	$ 85	$ 938	$ 790

Other & Total Upstream

	Other		Total Upstream	
	2004	2003	2004	2003
Revenues, Net of Royalties	$ 232	$ 180	$ 7,256	$ 5,797
Expenses				
Production and mineral taxes	-	-	311	164
Transportation and selling	-	-	472	429
Operating	222	170	1,026	872
Operating Cash Flow	$ 10	$ 10	$ 5,447	$ 4,332

Capital Expenditures (Continuing Operations)

	Three Months Ended December 31,		Year Ended December 31,	
	2004	2003	2004	2003
Upstream				
Canada	$ 742	$ 911	$ 3,079	$ 3,198
United States	695	342	1,549	968
Other Countries	30	15	79	78
	1,467	1,268	4,707	4,244
Midstream & Market Optimization	24	69	64	276
Corporate	18	69	46	107
Total	$ 1,509	$ 1,406	$ 4,817	$ 4,627

On December 17, 2004, the Company 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 holds the assets in trust for the Company. Pursuant to the agreement with Brown Ranger LLC, the Company operates the properties, receives all the revenue and pays all of the expenses associated with the properties. The assets will be transferred to the Company at the earlier of June 15, 2005 or upon the disposition of certain natural gas and crude oil properties by the Company. The Company has determined that the relationship with Brown Ranger LLC represents an interest in a VIE and that the Company is the primary beneficiary of the VIE. The Company has consolidated Brown Ranger

LLC from the date of acquisition.

In addition to the capital expenditures, during 2004, the Company divested of mature conventional oil and natural gas assets and other property, plant and equipment for proceeds of $1,144 million (2003 - $301 million).

Property, Plant and Equipment and Total Assets

	Property, Plant and Equipment		Total Assets	
	As at December 31,		As at December 31,	
	2004	2003	2004	2003
Upstream	$ 22,097	$ 16,757	$ 26,118	$ 19,416
Midstream & Market Optimization	804	784	1,904	1,879
Corporate	239	229	1,412	489
Assets of Discontinued Operations (Note 5)			1,779	2,326
Total	$ 23,140	$ 17,770	$ 31,213	$ 24,110

5. DISCONTINUED OPERATIONS

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. The Company'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. The majority of the Company's revenue in the United Kingdom was earned from a single customer who has a high quality investment grade credit rating. A gain on sale of approximately $1.4 billion was recorded. Accordingly, these operations have been accounted for as discontinued operations.

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

In 2003, in two separate transactions, the Company completed the sale of its 13.75 percent working interest and a gross overriding royalty in the Syncrude Joint Venture ("Syncrude") for net cash consideration of $999 million.

On January 2, 2003 and January 9, 2003, the Company completed the sales of its interests in the Cold Lake Pipeline System and Express Pipeline System for total consideration of approximately $1 billion, including assumption of related long-term debt by the purchaser, and recorded an after-tax gain on sale of $169 million.

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

Consolidated Statement of Earnings

For the three months ended December 31

	Ecuador		United Kingdom		Syncrude	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 173	$ 166	$ 27	$ 45	$ (1)	$ -
Expenses						
Production and mineral taxes	19	8	-	-	-	-
Transportation and selling	11	21	7	6	-	-
Operating	36	33	4	8	-	-
Depreciation, depletion and amortization	66	72	25	21	-	-
Interest, net	(2)	4	(4)	-	-	-
Accretion of asset retirement obligation	-	-	-	1	-	-
Foreign exchange loss (gain)	4	1	(5)	(5)	-	-
(Gain) loss on dispositions	-	-	(1)	1	-	-
(Gain) loss on discontinuance	-	-	(1,364)	-	2	-
	134	139	(1,338)	32	2	-
Net Earnings (Loss) Before Income Tax	39	27	1,365	13	(3)	-
Income tax (recovery) expense	(1)	44	10	17	-	-
Net Earnings (Loss) From Discontinued Operations	$ 40	$ (17)	$ 1,355	$ (4)	$ (3)	$ -

	For the three months ended December 31		
	Midstream - Pipelines	Total	
	2003	2004	2003
Revenues, Net of Royalties	$ -	$ 199	$ 211
Expenses			
Production and mineral taxes	-	19	8
Transportation and selling	-	18	27
Operating	-	40	41
Depreciation, depletion and amortization	-	91	93
Interest, net	-	(6)	4
Accretion of asset retirement			

obligation	-	-	1
Foreign exchange loss (gain)	-	(1)	(4)
(Gain) loss on dispositions	-	(1)	1
(Gain) loss on discontinuance	-	(1,362)	-
	-	(1,202)	171
Net Earnings (Loss) Before Income Tax	-	1,401	40
Income tax (recovery) expense	-	9	61
Net Earnings (Loss) From Discontinued Operations	$ -	$ 1,392	$ (21)

Included in United Kingdom Revenues, Net of Royalties for the three months ended December 31, 2004 is $43 million related to realized losses on terminated risk management contracts for the United Kingdom crude oil volumes.

Consolidated Statement of Earnings

	For the year ended December 31					
	Ecuador		United Kingdom		Syncrude	
	2004	2003	2004	2003	2004	2003
Revenues, Net of Royalties	$ 471	$ 412	$ 153	$ 118	$ (1)	$ 87
Expenses						
Production and mineral taxes	61	25	-	-	-	-
Transportation and selling	60	45	36	16	-	2
Operating	125	83	36	18	-	46
Depreciation, depletion and amortization	263	159	118	74	-	7
Interest, net	(3)	4	(9)	-	-	-
Accretion of asset retirement obligation	1	1	3	1	-	-
Foreign exchange loss (gain)	5	2	(2)	(5)	-	-
(Gain) loss on dispositions	-	-	(1)	1	-	-
(Gain) loss on discontinuance	-	-	(1,364)	-	2	-
	512	319	(1,183)	105	2	55
Net Earnings (Loss) Before Income Tax	(41)	93	1,336	13	(3)	32
Income tax (recovery) expense	(8)	61	(2)	20	-	8

Net Earnings (Loss)

From Discontinued Operations	$ (33)	$ 32	$ 1,338	$ (7)	$ (3)	$ 24

	For the year ended December 31		
	Midstream - Pipelines	Total	
	2003	2004	2003
Revenues, Net of Royalties	$ -	$ 623	$ 617
Expenses			
Production and mineral taxes	-	61	25
Transportation and selling	-	96	63
Operating	-	161	147
Depreciation, depletion and amortization	-	381	240
Interest, net	-	(12)	4
Accretion of asset retirement obligation	-	4	2
Foreign exchange loss (gain)	-	3	(3)
(Gain) loss on dispositions	-	(1)	1
(Gain) loss on discontinuance	(220)	(1,362)	(220)
	(220)	(669)	259
Net Earnings (Loss) Before Income Tax	220	1,292	358
Income tax (recovery) expense	51	(10)	140
Net Earnings (Loss) From Discontinued Operations	$ 169	$ 1,302	$ 218

Consolidated Balance Sheet

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

	As at December 31						
	Ecuador	United Kingdom	Syncrude	Total	Ecuador	United Kingdom	Total
	2004				2003		
Assets							
Cash and cash equivalents	$ 2	$ 12	$ -	$ 14	$ 2	$ 33	$ 35
Accounts receivable and							

accrued revenues	111	13	-	124	79	123	202
Risk management	3	-	-	3	-	-	-
Inventories	15	-	-	15	16	-	16
	131	25	-	156	97	156	253
Property, plant and equipment, net	1,295	-	-	1,295	1,254	521	1,775
Investments and other assets	328	-	-	328	291	7	298
	$1,754	$ 25	$ -	$1,779	$1,642	$ 684	$2,326
Liabilities							
Accounts payable and accrued liabilities	$ 61	$ 32	$ 3	$ 96	$ 103	$ 128	$ 231
Income tax payable	101	-	-	101	33	-	33
Risk management	72	-	-	72	-	-	-
	234	32	3	269	136	128	264
Asset retirement obligation	22	-	-	22	19	28	47
Future income taxes	80	11	-	91	93	113	206
	336	43	3	382	248	269	517
Net Assets of Discontinued Operations	$1,418	$ (18)	$ (3)	$1,397	$1,394	$ 415	$1,809

Acquisition / Disposition

On January 31, 2003, the Company acquired the Ecuador interests of Vintage Petroleum Inc. ("Vintage") for net cash consideration of $116 million. During the fourth quarter of 2003, the Company disposed of its interest in Block 27 in Ecuador for approximately $14 million.

Contingencies

In Ecuador, a subsidiary of the Company has a 40 percent non-operated economic interest in relation to Block 15 pursuant to a contract with a subsidiary of Occidental Petroleum Corporation. During the third quarter, Occidental Petroleum Corporation filed a Form 8-K indicating 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 Form 8-K, Occidental Petroleum Corporation indicated that it believes it has complied with all material obligations under the Participation Contract and that any termination of the Participation Contract by Ecuador based upon these stated allegations would be unfounded and would constitute an unlawful expropriation under international treaties.

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

6. DISPOSITIONS (ACQUISITIONS)

On December 22, 2004, the Company sold 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. On December 15, 2004, the Company sold its 25 percent limited partnership interest in Kingston CoGen Limited Partnership for net cash consideration of $25 million, recording a pre-tax 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 on sale of $34 million.

On February 18, 2004, the Company sold its 53.3 percent interest in Petrovera Resources ("Petrovera") for approximately $287 million, including working capital adjustments. In order to facilitate the transaction, the Company purchased the 46.7 percent interest of its partner for approximately $253 million, including working capital adjustments, and then sold the 100 percent interest in Petrovera for a total of approximately $540 million, including working capital adjustments. In accordance with full cost accounting for oil and gas activities, proceeds were credited to property, plant and equipment.

On July 18, 2003, the Company acquired the common shares of Savannah Energy Inc. ("Savannah") for net cash consideration of $91 million. Savannah's operations are in Texas, USA. This purchase was accounted for using the purchase method with the results reflected in the consolidated results of the Company from the date of acquisition.

Other dispositions of discontinued operations are disclosed in Note 5.

7. FOREIGN EXCHANGE GAIN

	Three Months Ended December 31,		Year Ended December 31,	
	2004	2003	2004	2003
Unrealized Foreign Exchange Gain on Translation of U.S. Dollar Debt Issued in Canada	$ (163)	$ (141)	$ (285)	$ (545)
Realized Foreign Exchange Gains	(41)	(20)	(132)	(53)
	$ (204)	$ (161)	$ (417)	$ (598)

8. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended December 31,		Year Ended December 31,	
	2004	2003	2004	2003
Current				
Canada	$ 89	$ (118)	$ 594	$ (136)
United States	(30)	29	(12)	39
Other	(3)	(5)	(15)	(16)
Total Current Tax	56	(94)	567	(113)
Future	461	133	200	836
Future Tax Rate Reductions(x)	-	3	(109)	(359)
Total Future Tax	461	136	91	477
	$ 517	$ 42	$ 658	$ 364

(x) On March 31, 2004, the Alberta government substantively enacted the income tax rate reduction previously announced in February 2004.

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

Three Months Ended Year Ended

	December 31, 2004	December 31, 2003	December 31, 2004	December 31, 2003
Net Earnings Before Income Tax	$ 1,705	$ 489	$ 2,869	$ 2,506
Canadian Statutory Rate	39.1%	41.0%	39.1%	41.0%
Expected Income Tax	667	200	1,123	1,026
Effect on Taxes Resulting from:				
Non-deductible Canadian crown payments	38	55	192	231
Canadian resource allowance	(59)	(52)	(246)	(258)
Canadian resource allowance on unrealized risk management losses	(37)	-	(10)	-
Statutory and other rate differences	(10)	(24)	(55)	(45)
Effect of tax rate changes	-	3	(109)	(359)
Non-taxable capital gains	(50)	(48)	(91)	(119)
Previously unrecognized capital losses	7	(48)	17	(119)
Tax basis retained on dispositions	(17)	-	(179)	-
Large corporations tax	11	2	24	27
Other	(33)	(46)	(8)	(20)
	$ 517	$ 42	$ 658	$ 364
Effective Tax Rate	30.3%	8.6%	22.9%	14.5%

9. LONG-TERM DEBT

	As at December 31, 2004	As at December 31, 2003
Canadian Dollar Denominated Debt		
Revolving credit and term loan borrowings	$ 1,515	$ 1,425
Unsecured notes and debentures	1,309	1,335
Preferred securities	-	252
	2,824	3,012
U.S. Dollar Denominated Debt		
Revolving credit and term loan borrowings	399	417
Unsecured notes and debentures	4,641	2,713
Preferred securities	-	150
	5,040	3,280
Increase in Value of Debt Acquired(x)	66	83
Current Portion of Long-Term Debt	(188)	(287)
	$ 7,742	$ 6,088

(x) Certain of the notes and debentures of the Company were acquired in business combinations and were accounted for at their fair value at the dates of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 22 years.

To fund the acquisition of Tom Brown, Inc., the Company arranged a $3 billion non-revolving term loan facility with a group of the

Company's lenders. At December 31, 2004, the facility has been completely repaid and cancelled.

10. ASSET RETIREMENT OBLIGATION

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

	As at December 31, 2004	As at December 31, 2003
Asset Retirement Obligation, Beginning of Year	$ 383	$ 288
Liabilities Incurred	98	45
Liabilities Settled	(16)	(23)
Liabilities Disposed	(35)	-
Change in Estimated Future Cash Flows	124	-
Accretion Expense	22	17
Other	35	56
Asset Retirement Obligation, End of Year	$ 611	$ 383

11. SHARE CAPITAL

	December 31, 2004		December 31, 2003	
(millions)	Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year	460.6	$ 5,305	478.9	$ 5,511
Shares Issued under Option Plans	9.7	281	5.5	114
Shares Repurchased	(20.0)	(287)	(23.8)	(320)
Common Shares Outstanding, End of Year	450.3	$ 5,299	460.6	$ 5,305

On October 26, 2004, the Company received regulatory approval for a new Normal Course Issuer Bid commencing October 29, 2004. Under this bid, the Company may purchase for cancellation up to 23,114,500 of its Common Shares, representing five percent of the approximately 462.29 million Common Shares outstanding as of the filing of the bid on October 22, 2004. On February 4, 2005, the Company received regulatory approval for an amendment to the Normal Course Issuer Bid which increases the number of shares available for purchase from five percent of the issued and outstanding Common Shares to ten percent of the public float of Common Shares (a total of approximately 46.1 million Common Shares). The current Normal Course Issuer Bid expires on October 28, 2005.

During the quarter, the Company purchased, for cancellation, 14,493,600 Common Shares (Year-to-date - 19,983,600 Common Shares) for total consideration of approximately $774 million (Year-to-date - $1,004 million). Of the total amount paid, $287 million was charged to Share capital, $46 million was charged to Paid in surplus and $671 million was charged to Retained earnings.

The Company has stock-based compensation plans that allow employees and directors to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the 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 ten years from the date the options were granted.

The following tables summarize the information about options to purchase Common Shares at December 31, 2004:

Weighted

	Stock Options (millions)	Average Exercise Price (C$)
Outstanding, Beginning of Year	28.8	43.13
Exercised	(9.7)	36.63
Forfeited	(1.0)	47.50
Outstanding, End of Year	18.1	46.29
Exercisable, End of Year	10.8	45.09

	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$)
13.50 to 19.99	0.1	0.2	18.49	0.1	18.49
20.00 to 24.99	0.6	3.5	22.69	0.6	22.69
25.00 to 29.99	0.4	1.3	26.18	0.4	26.18
30.00 to 43.99	0.5	1.7	40.18	0.4	39.93
44.00 to 53.00	16.5	2.4	47.97	9.3	47.87
	18.1	2.4	46.29	10.8	45.09

The Company has recorded stock-based compensation expense in the Consolidated Statement of Earnings for stock options granted to employees and directors in 2003 using the fair-value method. Stock options granted in 2004 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, 2004 would have been $2,570 million; $5.60 per common share - basic; $5.53 per common share - diluted (2003 - $418 million; $0.90 per common share - basic; $0.90 per common share - diluted). Pro forma Net Earnings and Net Earnings per Common Share for the year ended December 31, 2004 would have been $3,476 million; $7.55 per common share - basic; $7.43 per common share - diluted (2003 - $2,326 million; $4.91 per common share - basic; $4.85 per common share - diluted).

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

	December 31, 2003
Weighted Average Fair Value of Options Granted (C$)	$ 12.21
Risk-Free Interest Rate	3.87%
Expected Lives (years)	3.00
Expected Volatility	0.33
Annual Dividend per Share (C$)	$ 0.40

12. COMPENSATION PLANS

The tables below outline certain information related to the Company's compensation plans at December 31, 2004. Additional information is contained in Note 16 of the Company's annual audited Consolidated Financial Statements for the year ended December 31, 2003.

A) Pensions

The following table summarizes the net benefit plan expense:

	Three Months Ended December 31,		Year Ended December 31,	
	2004	2003	2004	2003
Current Service Cost	$ 2	$ 1	$ 6	$ 6
Interest Cost	5	3	14	12
Expected Return on Plan Assets	(4)	(2)	(12)	(9)
Plan Amendment	-	2	-	2
Amortization of Net Actuarial Loss	1	1	4	4
Amortization of Transitional Obligation	(1)	-	(2)	(2)
Amortization of Past Service Cost	1	(2)	2	(1)
Expense for Defined Contribution Plan	9	3	19	12
Net Benefit Plan Expense	$ 13	$ 6	$ 31	$ 24

At December 31, 2004, $17 million has been contributed to the pension plans.

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

The following table summarizes the information about SAR's at December 31, 2004:

	Outstanding SAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	1,175,070	35.87
Exercised	(698,775)	35.48
Forfeited	(11,040)	29.25
Outstanding, End of Year	465,255	36.61
Exercisable, End of Year	465,255	36.61
U.S. Dollar Denominated (US$)		
Outstanding, Beginning of Year	753,417	28.98
Exercised	(365,647)	29.19
Forfeited	(1,840)	25.29
Outstanding, End of Year	385,930	28.80
Exercisable, End of Year	385,930	28.80

The following table summarizes the information about Tandem SAR's at December 31, 2004:

	Outstanding Tandem SAR's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	-	-
Granted	1,080,450	55.31

Forfeited	(212,950)	54.37
Outstanding, End of Year	867,500	55.54
Exercisable, End of Year	-	-

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

The following table summarizes the information about DSU's at December 31, 2004:

	Outstanding DSU's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	319,250	48.68
Granted, Directors	58,931	54.04
Units, in Lieu of Dividends	3,208	59.86
Exercised	(6,083)	48.68
Outstanding, End of Year	375,306	49.61
Exercisable, End of Year	293,955	52.55

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

The following table summarizes the information about PSU's at December 31, 2004:

	Outstanding PSU's	Weighted Average Exercise Price
Canadian Dollar Denominated (C$)		
Outstanding, Beginning of Year	126,283	46.52
Granted	1,690,790	53.95
Forfeited	(169,970)	53.51
Outstanding, End of Year	1,647,103	53.42
Exercisable, End of Year	-	-
U.S. Dollar Denominated (US$)		
Outstanding, Beginning of Year	-	-
Granted	250,224	41.12
Forfeited	(25,609)	41.12
Outstanding, End of Year	224,615	41.12
Exercisable, End of Year	-	-

13. PER SHARE AMOUNTS

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

	Three Months Ended				Year Ended
	March 31,	June 30,	September 30,	December 31,	December 31,

(millions)	2004	2004	2004	2004	2003	2004	2003
Weighted Average Common Shares Outstanding - Basic	460.9	460.3	461.7	458.8	462.3	460.4	474.1
Effect of Dilutive Securities	6.2	5.2	4.5	6.1	3.6	7.6	5.6
Weighted Average Common Shares Outstanding - Diluted	467.1	465.5	466.2	464.9	465.9	468.0	479.7

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

As a means of managing commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts. None of these risk management contracts qualify or have been designated as accounting hedges. The following information presents all positions for financial instruments only.

As discussed in Note 2, 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 deferred loss 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. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

The following table presents a reconciliation of the change in the unrealized amounts from January 1, 2004 to December 31, 2004:

		Net Deferred Amounts Recognized on Transition	Fair Market Value	Total Unrealized Gain/ (Loss)
Fair Value of Contracts, January 1, 2004	(Note 2)	$ 235	$ (235)	$ -
Change in Fair Value of Contracts Still Outstanding at December 31, 2004		-	78	78
Fair Value of Contracts Realized During 2004		(307)	307	-
Fair Value of Contracts Entered into During 2004		-	(339)	(339)
Fair Value of Contracts Outstanding		$ (72)	$ (189)	$ (261)
Premiums Paid on Collars and Options			110	
Fair Value of Contracts Outstanding and Premiums Paid, End of Year			$ (79)	
Amounts Allocated to Continuing Operations		$ (73)	$ (10)	$ (190)
Amounts Allocated to Discontinued Operations		1	(69)	(71)
		$ (72)	$ (79)	$ (261)

The total realized loss recognized in net earnings for the quarter and year-to-date ended December 31, 2004 was $155 million ($227 million, before tax) and $464 million ($686 million, before tax), respectively. At December 31, 2004, 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, 2004
Remaining Deferred Amounts Recognized on Transition	
Accounts receivable and accrued revenues	$ 11
Investments and other assets	4
Accounts payable and accrued liabilities	44
Other liabilities	44
Net Deferred Gain - Continuing Operations	$ 73
Net Deferred Loss - Discontinued Operations	(1)
	$ 72
Risk Management	
Current asset	$ 336
Long-term asset	87
Current liability	241
Long-term liability	192
Net Risk Management Liability - Continuing Operations	$ (10)
Net Risk Management Liability - Discontinued Operations	(69)
	$ (79)

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

	As at December 31, 2004
Commodity Price Risk	
Natural gas	$ 107
Crude oil	(143)
Power	2
Foreign Currency Risk	-
Interest Rate Risk	24
Total Fair Value Positions - Continuing Operations	$ (10)
Total Fair Value Positions - Discontinued Operations	(69)
	$ (79)

Information with respect to power, foreign currency risk and interest rate risk contracts in place at December 31, 2003 is disclosed in Note 17 to the Company's annual audited Consolidated Financial Statements. No significant new contracts have been entered into as at December 31, 2004.

Natural Gas

At December 31, 2004, the Company's gas risk management activities from financial contracts had an unrealized gain of $36 million and a fair market value position of $107 million. The contracts were as follows:

Notional Fair

	Volumes (MMcf/d)	Term	Average Price		Market Value
Sales Contracts					
Fixed Price Contracts					
NYMEX Fixed Price	481	2005	6.72	US$/Mcf	$ 81
Colorado Interstate Gas (CIG)	113	2005	4.87	US$/Mcf	(27)
Other(1)	110	2005	5.21	US$/Mcf	(23)
NYMEX Fixed Price	525	2006	5.66	US$/Mcf	(105)
Colorado Interstate Gas (CIG)	100	2006	4.44	US$/Mcf	(37)
Other(1)	171	2006	4.85	US$/Mcf	(59)
Collars and Other Options					
Purchased NYMEX Put Options	906	2005	5.46	US$/Mcf	29
Other(2)	5	2005	4.57 - 7.23	US$/Mcf	-
NYMEX 3-Way Call Spread	180	2005	5.00/6.69/7.69	US$/Mcf	(13)
Purchased NYMEX Put Options	210	2006	5.00	US$/Mcf	5
Basis Contracts					
Fixed NYMEX to AECO Basis	877	2005	(0.66)	US$/Mcf	70
Fixed NYMEX to Rockies Basis	268	2005	(0.49)	US$/Mcf	19
Other(3)	442	2005	(0.47)	US$/Mcf	4
Fixed NYMEX to AECO Basis	703	2006	(0.65)	US$/Mcf	41
Fixed NYMEX to Rockies Basis	312	2006	(0.57)	US$/Mcf	14
Fixed NYMEX to CIG Basis	279	2006	(0.83)	US$/Mcf	(9)
Other(3)	182	2006	(0.36)	US$/Mcf	2
Fixed Rockies to CIG Basis	12	2007	(0.10)	US$/Mcf	-
Fixed NYMEX to AECO Basis	345	2007-2008	(0.65)	US$/Mcf	17
Fixed NYMEX to Rockies Basis	248	2007-2008	(0.57)	US$/Mcf	14
Fixed NYMEX to CIG Basis	110	2007-2009	(0.68)	US$/Mcf	5
Purchase Contracts					
Fixed Price Contracts					
Waha Purchase	27	2005	5.90	US$/Mcf	(2)
Waha Purchase	23	2006	5.32	US$/Mcf	3
					29
Gas Storage Optimization Financial Positions					2
Gas Marketing Financial Positions(4)					5
Total Unrealized Gain on Financial Contracts					36
Premiums Paid on Options					71
Total Fair Value Positions					$ 107

(1) Other Fixed Price Contracts relate to various price points at San Juan, Waha, Houston Ship Channel ("HSC"), Colorado Interstate Gas ("CIG") and Rockies.
(2) Other Collars and Other Options relate to collars at Permian, San Juan, Waha, CIG, HSC, Mid-Continent, Rockies and Texas Oklahoma.
(3) Other Basis Contracts relate to San Juan, CIG, HSC, Mid-Continent, Waha and Ventura.
(4) The gas marketing activities are part of the daily ongoing operations of the Company's proprietary production management.

Crude Oil

At December 31, 2004, the Company's oil risk management activities from all financial contracts had an unrealized loss of $251 million and a fair market value position of $(212) million. The contracts were as follows:

	Notional Volumes (bbl/d)	Term	Average Price (US$/bbl)	Fair Market Value
Fixed WTI NYMEX Price	41,000	2005	28.41	$ (209)
Costless 3-Way Put Spread	9,000	2005	20.00/25.00/28.78	(45)
Unwind WTI NYMEX Fixed Price	(4,500)	2005	35.90	11
Purchased WTI NYMEX Call Options	(38,000)	2005	49.76	13
Purchased WTI NYMEX Put Options	35,000	2005	40.00	13
Fixed WTI NYMEX Price	15,000	2006	34.56	(31)
Purchased WTI NYMEX Put Options	22,000	2006	27.36	(2)
				(250)
Crude Oil Marketing Financial Positions(1)				(1)
Total Unrealized Loss on Financial Contracts				(251)
Premiums Paid on Options				39
Total Fair Value Positions				$ (212)
Total Fair Value Positions - Continuing Operations				(143)
Total Fair Value Positions - Discontinued Operations				(69)
				$ (212)

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

15. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2004.

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