July 25, 2002

ENCANA

second quarter report 2

EnCana earns $458 million during inaugural quarter, generates $938 million of cash flow

Oil and natural gas sales rise 10 percent, offshore exploration success continues, gas production growth on double-digit pace in B.C. and U.S. Rockies

Calgary, Alberta (July 25, 2002) – EnCana Corporation (TSX & NYSE: ECA) earned $458 million, or $0.97 per share diluted, and generated $938 million of cash flow, or $2.00 per share diluted, in the second quarter of 2002. Included in the second quarter earnings is an unrealized after tax gain of $134 million, or $0.29 per share diluted, related to foreign exchange gains on EnCana's US$-denominated debt. This had no impact on cash flow. Daily oil and gas sales reached 693,104 barrels of oil equivalent, up more than 10 percent from the pro forma second quarter results of EnCana's founding companies one year earlier.

All references to 2001 production and six-month 2002 financial information in this news release text and tables for EnCana are presented on a pro forma basis as if the merger of PanCanadian Energy Corporation ("PanCanadian") and Alberta Energy Company Ltd. ("AEC") had occurred at the beginning of the respective periods.

"I'm pleased to report that our merger is complete and EnCana is forging full-speed ahead. We've achieved strong financial results with a growing production base that is on track to achieve our 2002 sales targets," said Gwyn Morgan, EnCana's President and Chief Executive Officer. "Our Onshore North America division is expected to achieve double-digit production growth while outstanding results in new exploration basins offer exciting future potential. We've recently announced that our Buzzard discovery, a major light oil find in the U.K. central North Sea, is moving to development planning. In addition, we are a 25 percent owner in a significant Gulf of Mexico find at Tahiti that could contain more than an estimated 400 million barrels of recoverable oil.

"In EnCana's first three months of operations, our board of directors and executive team have clearly defined an EnCana strategy that's focused, first and foremost, on core exploration and production ventures in North America and in select international locations. In keeping with this, we recently announced plans to sell our interests in two major oil pipelines in order to re-deploy the capital into our rich inventory of upstream plus natural gas storage opportunities," Morgan said.

STRONG OIL AND NATURAL GAS GROWTH CONTINUES IN SECOND QUARTER

EnCana's second quarter natural gas production averaged 2.7 billion cubic feet per day, up 11 percent over pro forma results in the second quarter of 2001. During the quarter, 118 million cubic feet per day were injected into storage, yielding second quarter sales of 2.6 billion cubic feet per day. Oil and natural gas liquids sales averaged 263,076 barrels per day, up about seven percent. Conventional operating plus administrative costs were approximately $4.60 per barrel of oil equivalent in the quarter. EnCana drilled 560 net wells in the second quarter.

For the three months ended June 30, 2002, EnCana's highlights include:
- Net earnings of $458 million, or $0.97 per common share diluted;
- Cash flow of $938 million, or $2.00 per common share diluted;
- Natural gas sales of 2,580 million cubic feet per day, up 12 percent from pro forma second quarter of 2001, with the average realized price declining 38 percent to $4.02 per thousand cubic feet;
- Crude oil and natural gas liquids sales of 263,076 barrels per day, up seven percent from pro forma second quarter of 2001, with the average realized price up eight percent to $31.48 per barrel;
- Total capital investment, excluding dispositions, of $1,446 million; and
- A strong financial position with debt to capitalization of 39 percent (all preferred securities included as debt).

SECOND QUARTER FINANCIAL RESULTS STRONG DESPITE LOWER GAS PRICES

Despite significantly lower natural gas prices, EnCana achieved strong financial performance. EnCana's average realized gas price in the second quarter was $4.02 per thousand cubic feet, compared to $6.46 per thousand cubic feet for the same period one year earlier. Gas prices improved slightly in the second quarter from the first three months of 2002.

ENCANA FORWARD SALES STABILIZE GAS PRICES UNTIL EXPECTED RECOVERY BY FALL

As expected, summer gas prices have now weakened due to the high levels of North American gas storage and above-normal water levels for hydroelectric generation in the western half of North America. Western Canadian gas prices have recently been impacted by temporary capacity restrictions on pipelines out of Alberta. EnCana is well positioned during this current period of lower prices as it has sold forward approximately 1.4 billion cubic feet of gas per day until September 30, 2002. Fixed prices include 875 million cubic feet per day at an effective AECO price of C$4.24 per thousand cubic feet, 367 million cubic feet per day at an effective Opal, WY price of US$2.37 per thousand cubic feet and 205 million cubic feet per day at a NYMEX-related price of US$3.33 per thousand cubic feet. Looking to the fourth quarter, EnCana expects gas prices to strengthen as North American gas production continues to drop due to reduced drilling and high overall decline rates. EnCana is using its natural gas storage facilities, combined with increasing field capacity, to prepare for anticipated strong sales in the fourth quarter.

HEAVY OIL DIFFERENTIALS NARROWED SIGNIFICANTLY

In the second quarter of 2002, the average West Texas Intermediate crude oil benchmark price was US$26.27 per barrel, down six percent from US$27.98 per barrel for the same quarter in 2001. However, Canadian heavy oil differentials improved dramatically, narrowing 50 percent to US$5.43 from US$10.94 per barrel. Heavy oil prices have narrowed the gap on light grades this year due to tight supply demand fundamentals and the resumption of processing in May at the CITGO refinery in the U.S. Midwest. The differential for Ecuador oil improved from a year earlier, dropping to average US$3.78 from US$8.09 per barrel. Oil prices have continued to strengthen through 2002 due to a number of factors including the production management agreement between OPEC and non-OPEC producers, problems with Iraqi crude deliveries, the war on terrorism and indications that the world economy is improving.

SIX-MONTH PRO FORMA FINANCIAL AND OPERATING PERFORMANCE

For the first six months of 2002, EnCana earned pro forma $632 million, or $1.28 per share diluted, and generated $1.7 billion in cash flow, or $3.57 per share diluted. First-half sales averaged 696,969 barrels of oil equivalent per day, up 10 percent over pro forma sales from one year earlier. First-half daily sales were comprised of 2.7 billion cubic feet of natural gas, up 16 percent in the past year, and 255,008 barrels of oil and natural gas liquids, up three percent over pro forma sales for the first half of 2001. EnCana drilled 1,561 net wells in the first half.

These pro forma six-month results represent EnCana as if it had existed as a merged Company for the periods noted, whereas the attached six-month financial statements are actuals, reflecting EnCana second quarter results and PanCanadian first quarter results alone.

2002 CAPITAL INVESTMENT TO FUND MULTIPLE GROWTH OPPORTUNITIES

"Since receiving shareholder approval of the merger in early April, our new business units have conducted a thorough review of our portfolio of opportunities. We have identified an even stronger array of multi-year, organic growth opportunities that are expected to generate rates of return exceeding 20 percent after tax at current strip prices. While we may be facing softer natural gas prices in the very short term, the inaugural EnCana capital program is aimed at building productive capacity for what we believe will soon be strong gas prices.

"In our three current key producing platforms – Western Canada, the U.S. Rockies and Ecuador – we have identified profitable organic growth opportunities that are expected to generate growth of 10 percent plus for the next several years. Starting in 2005, exciting new exploration discoveries in three additional platforms – the U.K. North Sea, the Gulf of Mexico and off Canada's East Coast – are expected to layer more growth on top of that solid base growth," Morgan said.

To capitalize on these opportunities, EnCana's board of directors has approved a 2002 gross capital budget of approximately $5 billion. The Company expects to complete upstream asset dispositions this year of approximately $500 million and dispositions of about $1.5 billion in midstream assets. These dispositions, combined with about $460 million in recently completed acquisitions – including U.S. Rockies natural gas assets, would result in net capital investment of approximately $3.5 billion.

Of the $5 billion capital budget, $3.5 billion is planned for Onshore North America projects. This investment is directed about 65 percent to gas and 35 percent to oil projects. International development of $600 million is directed to longer term development of production growth in Ecuador, the U.K. central North Sea and the Gulf of Mexico. EnCana's international and offshore exploration investment is about $700 million, directed to additional appraisal on exploration success in the Gulf of Mexico and the North Sea, plus exploration in other select international locations.

2002 ENCANA CAPITAL BUDGET

	($ millions)
Primary Capital Investment	
Onshore North America	
Natural gas	$ 2,240
Syncrude	300
SAGD	200
Other oil	760
Total	3,500
Offshore and International Operations	600
Offshore and New Ventures Exploration	700
Midstream and Marketing	250
Gross Capital Investment	$ 5,050
Acquisitions and Dispositions	
Acquisitions upstream	460
Dispositions upstream (forecast)	(500)
Dispositions midstream (forecast)	(1,500)
Net Capital Investment	$ 3,510

SALES TARGETS ON TRACK FOR 2002

EnCana's 2002 daily sales target is forecast to grow by about 10 percent from 2001 pro forma sales. The 2002 forecast is between 2,675 million and 2,745 million cubic feet of gas and 245,000 and 264,000 barrels of oil, for a total daily sales forecast of between 690,000 and 721,000 barrels of oil equivalent. Sales in 2003 are forecast to rise about 13 percent above the midpoint of the 2002 forecast, reaching between 775,000 and 825,000 barrels of oil equivalent per day.

Important Notice: Readers are cautioned that a portion of the six-month results and the comparisons to prior years' results are based on pro forma calculations and these pro forma results may not reflect all adjustments and reconciliations that may be required under Canadian generally accepted accounting principles. These pro forma results may not be indicative of the results that actually would have occurred or of the results that may be obtained in the future.

Financial Highlights

As at and for the Period Ending June 30, 2002 *($ millions, except per share amounts)*	**EnCana Three Months Actuals**	EnCana Six Months Pro Forma
Revenues, net of royalties and production taxes	**2,676**	4,915
Cash flow	**938**	1,727
Per share – basic	**2.03**	3.64
Per share – diluted	**2.00**	3.57
Net earnings	**458**	632
Per share – basic	**0.99**	1.31(1)
Per share – diluted	**0.97**	1.28
Capital investment, excluding dispositions	**1,446**	2,742
Total assets	**29,479**	n/a
Long-term debt	**7,525**	n/a
Preferred securities, including those of the subsidiary	**575**	n/a
Shareholders' equity	**12,960**	n/a
Debt-to-capitalization ratio (adjusted for working capital and including preferred securities as debt)	**39%**	n/a
Common Shares		
Outstanding June 30, 2002 *(millions)*	**476.3**	n/a
Weighted average diluted *(millions)*	**470.0**	483.5

(1) *Impact of including share options in earnings calculations*
As required by Canadian generally accepted accounting principles, the notes in EnCana's second quarter financial statements show that the inclusion of stock options as compensation expense in the calculations of earnings would have resulted in a reduction of 14 cents shown in basic earnings per share in the first half of 2002.

Operating Highlights

For the Three Months Ending June 30	**Q2 2002 Actuals**	Q2 2001 Pro Forma	Percent Change
Sales			
Total barrels of oil equivalent per day	**693,104**	628,894	+10
Natural gas *(million cubic feet per day)*	**2,580**	2,297	+12
Total liquids *(barrels per day)*	**263,076**	246,061	+7
North America			
Conventional oil and NGLs	**166,951**	152,487	+9
Syncrude	**24,295**	29,162	-17
International	**71,830**	64,412	+12
Prices			
North American gas price *($ per thousand cubic feet)*	**4.02**	6.46	-38
North American conventional oil price *($ per barrel)*			
Light/medium	**33.76**	30.38	+11
Heavy	**26.09**	17.92	+46
Syncrude *($ per barrel)*	**40.09**	42.27	-5
International crude oil *($ per barrel)*			
Ecuador	**31.63**	28.12	+12
U.K.	**37.78**	36.27	+4
Natural gas liquids *($ per barrel)*	**29.92**	36.83	-19
Total liquids *($ per barrel)*	**31.48**	29.06	+8

ENCANA CORPORATE DEVELOPMENTS

Integration on track after creation of EnCana Corporation on April 5, 2002

Following overwhelming support at separate meetings on April 4, 2002 of shareholders and optionholders of AEC and shareholders of PanCanadian, the Court of Queen's Bench of Alberta approved the merger of the two companies and EnCana Corporation was created on April 5, 2002. EnCana common shares began trading on the Toronto and New York stock exchanges on April 8, 2002 under the symbol "ECA." Immediately thereafter, the reorganization of the Company into decentralized, fully accountable business units was implemented. The Company has identified and is moving forward to achieve operating and administrative synergies of at least $250 million and capital synergies in excess of $250 million on a yearly pre-tax basis in 2003. An estimated $50 million in annual administrative synergies have been already achieved.

Dividends

The board of directors of EnCana declared a quarterly dividend of ten cents (10 cents) per share payable on September 30, 2002 to common shareholders of record as of September 13, 2002.

ENCANA OPERATIONAL HIGHLIGHTS

Onshore North America

Continued strong natural gas growth EnCana's North America natural gas production during the second quarter increased to 2.7 billion cubic feet per day, up 11 percent compared to pro forma results of the same period last year. The production increase came primarily from the U.S. Rockies and northeast British Columbia. The Onshore North America division drilled more than 540 net wells during the second quarter.

Acquisition of high-quality U.S. Rockies assets completed EnCana has completed the acquisition, for C$420 million (US$276 million), of approximately 500 billion cubic feet equivalent of established, long-life natural gas and associated natural gas liquids reserves and about 180,000 net acres of undeveloped land in the Piceance Basin of northwest Colorado. With this purchase, U.S. Rockies production increased in the month of June to about 490 million cubic feet of natural gas per day.

Since acquiring its first assets in the region in June 2000, EnCana has grown U.S. Rockies production through drilling and acquisitions by more than 3.5 times. With more than 1.4 million net undeveloped acres in Colorado, Wyoming, Montana and Utah, the Company is a leading producer in the region. Through the application of technical expertise to the Company's inventory of long-life, multi-zone, tight-gas formations that are prevalent in the region, EnCana expects to grow U.S. Rockies gas production by more than 15 percent per year over the next three years.

Greater Sierra staged for long-term natural gas growth Over the past four years, EnCana has identified one of North America's largest new regional gas plays in the Greater Sierra region of northeast British Columbia. Major land purchases in the first half of 2002 increased EnCana's land position to more than two million net acres of undeveloped land, making EnCana the leader in the play. In the first half of 2002, EnCana completed a successful 45 well program, adding about 150 billion cubic feet of established reserves. Daily gas production from Greater Sierra, currently about 150 million cubic feet, is targeted to more than double in the next three years, and continue to grow after that. EnCana is the leading explorer, producer and landholder in British Columbia – one of the fastest growing gas producing regions in North America.

Oil and natural gas liquids production rise Production of conventional oil and natural gas liquids from its Onshore North America division averaged 167,000 barrels per day in the second quarter of 2002, a nine percent increase from pro forma results of the second quarter of 2001. Growth is due primarily to the start up of EnCana's Foster Creek steam-assisted gravity drainage (SAGD) project in northeast Alberta, increased production at Suffield and enhanced oil recovery at the Company's Weyburn CO_2 project in Saskatchewan.

Two SAGD projects underway EnCana has started steam injection at the Company's SAGD project at Christina Lake, where first production is expected in the third quarter of 2002. Production from the world's first large-scale SAGD project – Foster Creek – averaged 12,000 barrels per day during the second quarter, slightly below expectations as it has taken longer than expected to bring water treatment facilities to full operating performance. Foster Creek production is forecast to reach the full design level of 20,000 barrels per day later this summer. In combination, EnCana's SAGD projects are expected to generate more than 120,000 barrels per day of production by 2007.

Syncrude costs and volumes impacted by scheduled maintenance EnCana's daily production from Syncrude during the second quarter of 2002 averaged 24,295 barrels, down 17 percent from the same period last year. Unit operating costs rose by $8.93 per barrel to average $30.47 per barrel in the second quarter of 2002 compared to the same period last year. Volumes were lower and costs higher because the planned 35-day maintenance of a coker unit took 52 days to complete due to additional maintenance required on the coker burner and the heavy gas oil hydrotreater. The work has been completed and Syncrude is currently operating at full production rates. Syncrude is currently producing in the range of 34,000 to 35,000 barrels per day, net to EnCana. The Company is expecting operating costs of approximately $18 to $19 per barrel for 2002.

Offshore and International Operations

Ecuador – strong second quarter sales Oil production in Ecuador, which is constrained by a lack of pipeline capacity, averaged 52,744 barrels of oil per day in the second quarter. Daily oil sales averaged 59,864 barrels, up 12 percent from the same period one year earlier due to the scheduling of tanker shipments leaving port. Construction of the OCP Pipeline is about 50 percent complete, with first oil shipments expected in mid-2003. EnCana is targeting to increase its Ecuador production to between 80,000 and 100,000 barrels per day by late in 2003. Achieving the upper end of the range requires approval by the Government of Ecuador to move onto adjacent lands to follow up on exploration success.

U.K. North Sea – Buzzard moves to development planning Development planning for the EnCana-operated Buzzard light oil discovery is underway following a very successful appraisal drilling program. The eight appraisal wells and sidetracks drilled to date have confirmed the nature and extent of the Buzzard field, located in the U.K. central North Sea and discovered in June 2001. The current estimate of oil-in-place is between 800 million and 1.1 billion barrels. Further study and analysis is underway to establish estimated potential recoverable reserve figures. A program to evaluate nearby exploration and satellite development potential has also begun.

East Coast of Canada – Deep Panuke project in regulatory review The Canada-Nova Scotia Offshore Petroleum Board and the National Energy Board are reviewing the development plan for EnCana's Deep Panuke natural gas project off the coast of Nova Scotia. EnCana continues to work closely with regulators with the objective of streamlining the regulatory process. Regulatory hearings for the project were expected to start in the third quarter of 2002, with a decision in the first quarter of 2003. Based on current assumptions, commercial production is targeted to begin in 2005, however the regulatory process has been slower than expected and EnCana will revisit its schedule once satisfactory regulatory approvals are obtained. Deep Panuke involves the production and processing of raw gas offshore, the transport of market-ready gas via sub-sea pipeline to Goldboro, Nova Scotia, and an interconnection with the Maritimes and Northeast Pipeline main transmission pipeline. The project is estimated to recover reserves of natural gas approaching one trillion cubic feet.

Offshore and New Ventures Exploration

U.K. North Sea – Black Horse well encounters hydrocarbons EnCana and its partner ExxonMobil completed drilling the Black Horse prospect located about 160 kilometres northeast of Aberdeen, Scotland on EnCana-operated licence P.185. The prospect straddles two licences: P.185 "Black Horse Area", where EnCana owns approximately 57 percent and ExxonMobil approximately 43 percent, and P.489, which is 100 percent EnCana. During testing, the well flowed light oil at a rate of 6,274 barrels per day and natural gas at 3.9 million cubic feet per day on a 24/64-inch choke. The well has been suspended. Evaluation of test results is underway to determine if the discovery has commercial potential.

In the recent U.K. 20th Licencing Round, EnCana and its partners were the successful bidders on five exploration blocks in the Company's central North Sea core area; four of these will be operated by EnCana.

Gulf of Mexico – Tahiti discovery moves to appraisal The operator of the Tahiti deepwater oil discovery, ChevronTexaco, recently estimated that the Gulf of Mexico find holds 400 million to 500 million barrels of recoverable oil. EnCana owns a 25 percent interest in Tahiti, located in Green Canyon Block 640, approximately 190 miles southwest of New Orleans in the deepwater Gulf of Mexico. Initial results of the Tahiti No. 1 well, drilled in 4,000 feet of water, indicate a high-quality reservoir sand with total net pay of more than 400 feet. Tahiti No. 1 is the second well in EnCana's four-well commitment to earn a 25-percent interest in 71 ChevronTexaco-operated blocks in the Mississippi Fanfold Belt in the Gulf of Mexico. Completion of the four-well program is expected by early 2003.

Midstream and Marketing

Maximizing value On July 9, 2002, EnCana announced that it is seeking potential buyers for its interests in two major oil pipelines – the 100-percent-owned Express Pipeline System and the 70-percent-owned Cold Lake Pipeline System. Both of these oil transportation systems deliver Canada's growing oil sands production to Canadian, U.S. Rocky Mountain and Midwest refineries.

The 1,717-mile Express Pipeline System is comprised of two major pipelines: Express, with a capacity of more than 172,000 barrels per day and Platte, delivering up to 150,000 barrels per day. The pipelines run from Alberta's oil transportation hub at Hardisty through Casper, WY to Wood River, IL. The Cold Lake Pipeline System is comprised of two delivery legs, each delivering oil from Cold Lake, Alberta to Edmonton and Hardisty, where it connects with Express and other intercontinental pipelines. The financial information related to the Express and Cold Lake pipeline systems has been presented as Discontinued Operations in the second quarter unaudited consolidated financial statements.

Midstream focused on gas storage, Wild Goose expansion approved by California regulator The key focus of EnCana's Midstream growth will be expansion of North America's largest independent gas storage network. The California Public Utilities Commission recently approved EnCana's application to more than double the size of the Wild Goose gas storage facility in northern California. Under the proposal, the facility's working gas capacity would expand from 14 billion to 29 billion cubic feet, withdrawal rates would climb from 200 million to 700 million cubic feet per day and injection rates would increase from 80 million to 450 million cubic feet per day. Construction started this week and expansion facilities are expected to be in service beginning April 2004. EnCana plans to aggressively pursue new North American gas storage opportunities in order to expand capacity to supply volumes at peak periods of demand in the anticipated growing market.

Energy services On April 25, the Company announced that it was discontinuing the former PanCanadian Houston-based merchant energy trading operations, a decision that was made following a strategic review of the merged Company's core operations. The Company has recorded a $49 million after tax loss, which is included in discontinued operations.

Operating cash flow forecast update EnCana's Midstream and Marketing division achieved $66 million of operating cash flow in the second quarter. The Company is forecasting 2002 operating cash flow of approximately $200 million from continuing operations and $150 million from discontinued operations. This has been revised downward from the previous forecast due to a number of factors, including a temporary reduction in gas price volatility, lower electricity prices than previously forecast in Alberta and the wind-down of EnCana's Houston-based merchant energy trading operations.

Financial Strength

EnCana possesses one of the strongest financial positions among upstream independents. At June 30, 2002, the Company's debt-to-capitalization ratio was 39:61 (all preferred securities included as debt). Second quarter core capital investment and acquisitions were $1,446 million. Dispositions were $240 million, bringing net capital investment to $1,206 million. EnCana maintains strong investment grade ratings from the major bond rating services: Dominion Bond Rating Service, A(low), Moody's Investment Service, Baa1, and Standard and Poor's, A-.

EnCana continues to strive to achieve best-in-class practices in all areas of operations, including corporate governance and disclosure.

"Each member of EnCana's executive team has a track record of more than 20 years of respected and credible business performance. The combined business experience of the 16-member board of directors is more than 450 years. Fifteen of EnCana's 16 directors are independent. The board maintains several independent committees – including reserves, compensation, pension, governance, audit and environment. EnCana's policy is to have 100 percent of its oil and gas reserves evaluated by external engineers. Integrity has always been at the core of our business practices as, over more than two decades, we have, step-by-step, built a world-class Company," Morgan said.

IMPORTANT NOTICE

This document and Alberta Energy Company Ltd.'s second quarter 2002 financial statements are filed on Sedar and posted on www.sedar.com.

This document, EnCana's pro forma consolidated six-month financial statements and supplemental information are posted on the Company Web site www.encana.com.

EnCana Corporation

EnCana is the largest North American based independent oil and gas company with an enterprise value of approximately C$28 billion. It is North America's largest independent natural gas producer and gas storage operator. Ninety percent of the Company's assets are in four key North American growth platforms: Western Canada, offshore Canada's East Coast, the U.S. Rocky Mountains and the Gulf of Mexico. EnCana is the largest producer and landholder in Western Canada and is a key player in Canada's emerging offshore East Coast basins. In the U.S., EnCana is one of the largest gas explorers and producers in the Rocky Mountain states and has a strong position in the deepwater Gulf of Mexico. The Company has two key high-potential international growth platforms: Ecuador, where EnCana is the largest private sector oil producer, and the U.K. central North Sea, where EnCana is the operator of a very large oil discovery. The Company also conducts high upside potential new ventures exploration in other parts of the world. EnCana is driven to be the industry's best-in-class benchmark in production cost, per-share growth and value creation for shareholders. EnCana common shares trade on the Toronto and New York stock exchanges under the symbol "ECA."

ADVISORY – In the interests of providing EnCana shareholders and potential investors with information regarding EnCana, including management's assessment of EnCana's 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 second quarter report include, but are not limited to: EnCana's internal projections, expectations or beliefs concerning future operating results, and various components thereof; future economic performance; the production and growth potential of its various assets, including assets in the U.S. Rockies, Greater Sierra, the U.K. central North Sea and Ecuador; the anticipated oil and natural gas prices for the remainder of 2002; the sources and deployment of expected capital in 2002; the timing of regulatory review regarding Deep Panuke and the projected production date from the Deep Panuke project; the anticipated timing for the completion of the discontinuance of EnCana's Houston-based merchant energy operations; projected increases in daily production of oil, natural gas and natural gas liquids to 2007; potential exploration; the potential success of certain projects such as SAGD and the expected rates of returns from projects; the ability to sell the Cold Lake and Express pipeline interests and the price realized on such sales; and the potential success of other exploratory wells in the Gulf of Mexico and the U.K. central North Sea.

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; imprecision of reserve estimates; 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 risk that the anticipated synergies to be realized by the merger of AEC and PanCanadian will not be realized; costs relating to the merger of AEC and PanCanadian being higher than anticipated and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by EnCana and its indirect wholly owned subsidiary, AEC. 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 herein are made as of the date of this second quarter report, 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 second quarter report are expressly qualified by this cautionary statement.

Further information on EnCana Corporation and Alberta Energy Company Ltd. is available on the Company's Web site, www.encana.com, or by contacting:

EnCana Corporate Development

Investor contacts:
Sheila McIntosh
Senior Vice-President, Investor Relations
(403) 645-2194

Greg Kist
Manager, Investor Relations
(403) 645-4737

Media contact:
Alan Boras
Manager, Media Relations
(403) 266-8300 or
(403) 645-4754

EnCana Corporation
Pro Forma Consolidated Statement of Earnings

(Unaudited)

($ millions, except per share amounts)	**EnCana** Six Months Ended June 30, 2002	**AEC** Three Months Ended March 31, 2002	**Pro Forma Adjustments** Note 1	**EnCana Pro Forma Consolidated**
Revenues, Net of Royalties and Production Taxes				
Upstream	$ 2,138	$ 835	$ (141)	$ 2,832
Midstream and Marketing	1,600	343	141	2,084
Other	(1)	–	–	(1)
	3,737	1,178	–	4,915
Expenses				
Transportation and selling	207	79	–	286
Operating	629	202	–	831
Purchased product	1,234	406	–	1,640
Administrative	61	24	–	85
Interest, net	130	61	9	200
Foreign exchange	(180)	(1)	–	(181)
Depreciation, depletion and amortization	794	302	45	1,141
Earnings Before the Undernoted	862	105	(54)	913
Income tax expense (recovery)	237	39	(23)	253
Net Earnings from Continuing Operations	625	66	(31)	660
Net Earnings from Discontinued Operations	(34)	6	–	(28)
Net Earnings	591	72	(31)	632
Distributions on Preferred Securities, Net of Tax	1	16	(5)	12
Net Earnings Attributable to Common Shareholders	$ 590	$ 56	$ (26)	$ 620

Earnings per Common Share	
Continuing operations	
Basic	$ 1.37
Diluted	$ 1.34
Net earnings	
Basic	$ 1.31
Diluted	$ 1.28

EnCana Corporation
Pro Forma Consolidated Statement of Cash Flow from Operations

(Unaudited)

($ millions, except per share amounts)	**EnCana** Six Months Ended June 30, 2002	**AEC** Three Months Ended March 31, 2002	**Pro Forma Adjustments** Note 1	**EnCana Pro Forma Consolidated**
Operating Activities				
Net earnings from continuing operations	$ 625	$ 66	$ (31)	$ 660
Depreciation, depletion and amortization	794	302	45	1,141
Future income taxes	141	19	(19)	141
Other	(257)	3	–	(254)
Cash Flow from Continuing Operations	1,303	390	(5)	1,688
Cash Flow from Discontinued Operations	24	15	–	39
Cash Flow	$ 1,327	$ 405	$ (5)	$ 1,727
Cash Flow per Common Share from Continuing Operations				
Basic				$ 3.56
Diluted				$ 3.49
Cash Flow per Common Share				
Basic				$ 3.64
Diluted				$ 3.57

EnCana Corporation
Note to Pro Forma Consolidated Financial Statements

June 30, 2002 *(Unaudited)*

1. BASIS OF PRESENTATION

These unaudited Pro Forma Consolidated Statement of Earnings and Consolidated Statement of Cash Flow from Operations have been prepared for information purposes using information contained in the following:

(a) EnCana's unaudited consolidated financial statements for the six months ended June 30, 2002

(b) AEC's unaudited consolidated financial statements for the three months ended March 31, 2002.

The pro forma adjustments include adjustments for financial statement presentation of segmented financial information. To be consistent with EnCana's segmented presentation, revenues associated with AEC's purchased gas activity have been reclassified from Upstream revenue.

All pro forma adjustments related to the purchase price allocation have been based upon the Business Combination information disclosed in Note 3 of the June 30, 2002 unaudited Consolidated Financial Statements of EnCana and assume that the transaction occurred on January 1, 2002.

Pro forma adjustments made in the unaudited Consolidated Statement of Earnings and unaudited Consolidated Statement of Cash Flow from Operations relate to (i) the recording of interest expense on the Capital Securities of AEC, (ii) the recording of Depreciation, depletion and amortization on the increase in the carrying value of Capital Assets resulting from the acquisition which has been allocated to capital assets that are subject to depreciation, depletion and amortization, and (iii) the recording of the future income tax benefits related to these additional expenses.

These unaudited Pro Forma Consolidated Financial Statements may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future.

EnCana Corporation
Management's Discussion and Analysis

June 30, 2002

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

In the interest of providing EnCana Corporation ("EnCana" or the "Company"), formerly PanCanadian Energy Corporation ("PanCanadian"), shareholders and potential investors with information regarding the Company, certain statements throughout this Interim Management's Discussion and Analysis ("MD&A") constitute forward-looking statements within the meaning of the United States *Private Securities Litigation Reform Act* of 1995. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this MD&A include, but are not limited to, statements with respect to: the Company's operating costs; oil and gas prices; the Company's crude oil, liquids and gas sales; the Company's cash flow and net earnings; the Company's production levels; the impact of hedges on the Company's revenues; capital investment levels; the sources of funding for capital investments; the anticipated timing and results of discontinuing the Houston-based merchant energy operation and of the proposed disposition of the Express and Cold Lake pipeline interests; the realization of the capital and cost synergies as part of the Company's merger with Alberta Energy Company Ltd. ("AEC") and the timing thereof, and future operating results and various components thereof.

Readers are cautioned not to place undue reliance on forward-looking information, as there can be no assurance that the plans, intentions or expectations upon which it is based will occur. By its nature, forward-looking information involves 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. Although the Company 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. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this MD&A include, but are not limited to: volatility of crude oil and natural gas prices, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in the Company's North American and foreign oil and gas and midstream operations, risks inherent in the Company's marketing operations, imprecision of reserves estimates, the Company's ability to replace and expand oil and gas reserves, the Company's ability to either generate sufficient cash flow from operations to meet its current and future obligations or obtain external sources of debt and equity capital, general economic and business conditions, the Company's ability to enter into or renew leases, the timing and costs of well and pipeline construction, the Company's ability to make capital investments and the amounts of capital investments, imprecision in estimating the timing, costs and levels of production and drilling, the results of exploration and development drilling, imprecision in estimates of future production capacity, the Company's ability to secure adequate product transportation, uncertainty in the amounts and timing of royalty payments, imprecision in estimates of product sales, changes in environmental and other regulations, political and economic conditions in the countries in which the Company operates including Ecuador, and such other risks and uncertainties described from time to time in the Company's reports and filings with the Canadian securities authorities and the United States Securities and Exchange Commission. Accordingly, the Company cautions that events or circumstances could cause actual results to differ materially from those predicted. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. Readers are further cautioned not to place undue reliance on forward-looking statements contained in this MD&A, which is as of the date hereof, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2002 and June 30, 2001 and the audited consolidated financial statements and MD&A of PanCanadian Energy Corporation ("PanCanadian", the Company's predecessor) for the year ended December 31, 2001.

CONSOLIDATED OVERVIEW

In the second quarter of 2002, EnCana's net earnings from continuing operations were $494 million, or $1.07 per common share compared with $445 million, or $1.74 per common share in the same period of 2001. Cash flow from continuing operations for the period was $916 million, or $1.99 per share compared with $601 million, or $2.35 per share last year. Increased production resulting primarily from the merger with Alberta Energy Company Ltd. ("AEC") helped to compensate for the lower natural gas prices in the quarter.

For the year to date, net earnings from continuing operations were $625 million, or $1.74 per share, a decrease of $263 million, or $1.73 per share from the corresponding period of 2001. Year-to-date cash flow from continuing operations was $1,303 million, or $3.64 per share compared with $1,313 million, or $5.14 per share in the six months ended June 2001. The decline in results was largely due to significantly weaker market prices for natural gas in the first half of 2002 compared with the exceptionally strong natural gas prices realized in the same period last year. The impact of lower natural gas prices was partially offset by increased production resulting primarily from the merger of the Company with AEC in April 2002.

Consolidated Financial Summary *($ millions, except per share amounts)*	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	**2002**	2001
Revenues, net of royalties and production taxes	**$ 2,676**	$ 1,136	**$ 3,737**	$ 2,811
Net earnings from continuing operations	**494**	445	**625**	888
– per share basic	**1.07**	1.74	**1.74**	3.47
– per share diluted	**1.05**	1.70	**1.71**	3.39
Net earnings	**458**	459	**591**	922
– per share basic	**0.99**	1.79	**1.65**	3.60
– per share diluted	**0.97**	1.75	**1.62**	3.52
Cash flow from continuing operations	**916**	601	**1,303**	1,313
– per share basic	**1.99**	2.35	**3.64**	5.14
– per share diluted	**1.95**	2.30	**3.57**	5.03
Cash flow	**938**	622	**1,327**	1,360
– per share basic	**2.03**	2.43	**3.70**	5.32
– per share diluted	**2.00**	2.38	**3.64**	5.21

On April 5, 2002, PanCanadian and AEC completed the merger of their two companies, creating EnCana Corporation. The companies satisfied all closing conditions, including receipt of approvals from shareholders of PanCanadian, shareholders and optionholders of AEC, and the Court of Queen's Bench of Alberta. Under the terms of the merger, AEC shareholders received 1.472 EnCana common shares for each AEC common share owned. For further information with respect to the merger transaction refer to Note 3 to the unaudited interim consolidated financial statements ("Consolidated Financial Statements").

The Consolidated Financial Statements include the results of AEC from the closing date of the merger. As such, the six-month amounts for 2002 reflect second quarter results of the combined companies together with first quarter results of PanCanadian only. The comparative figures reflect solely the 2001 results of PanCanadian.

In May 2002, the Company expanded its production, land holdings, and midstream assets in the U.S. Rocky Mountain region with the purchase of certain Colorado assets from subsidiaries of El Paso Corporation for approximately $420 million. This acquisition complements the Company's existing Piceance Basin gas production at Mamm Creek and the surrounding area near Rifle, Colorado.

On April 24, 2002, the Company adopted formal plans to exit from its Houston-based merchant energy operation, which was included in the Midstream and Marketing segment. The operation is being wound-down with an anticipated completion date by the end of the third quarter of this year. At June 30, 2002, an after-tax loss of $49 million has been recorded, which includes the expected costs associated with the wind-down of the Houston-based merchant energy operation. Upon review of additional information related to 2001 sales and purchases of natural gas by this U.S. operation, the Company determined that certain revenues and expenses should have been reflected in the financial statements in 2001 on a net basis as described in Note 5 to the Consolidated Financial Statements and as previously presented in the Company's unaudited interim consolidated financial statements for the first quarter of 2002. Certain of these 2001 natural gas sale and purchase transactions may be characterized as so-called "round-trip" transactions. The Company has received requests for information from several U.S. governmental agencies regarding these round-trip transactions. In addition, in connection with its investigation of Reliant Resources, Inc. and Reliant Energy, Inc., the U.S. Securities and Exchange Commission has issued a subpoena to the Company to produce all documents concerning round-trip transactions with those corporations. The Company is cooperating fully in responding to all of these requests.

On July 9, 2002, the Company announced plans to dispose of two major crude oil pipeline systems. The proposed disposition includes the Company's indirect 100 percent interest in the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System. It is anticipated that, upon the proposed disposition, capital will be re-deployed into exploration and production initiatives that are more consistent with EnCana's strategic direction.

The merchant energy and pipeline operations described above have both been accounted for as discontinued operations. The financial statements have been restated to reflect these discontinued operations as described in Note 5 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	**2002**	2001
Average AECO Price *($ per thousand cubic feet)*	**4.42**	7.38	**3.88**	9.37
Average NYMEX Price *(US$ per million British thermal units)*	**3.38**	4.39	**2.80**	5.31
WTI Average *(US$ per barrel)*	**26.27**	27.98	**23.95**	28.32
WTI-Bow River Differential *(US$ per barrel)*	**5.43**	10.94	**5.33**	11.40
Oriente Differential (Ecuador) *(US$ per barrel)*	**3.78**	8.09	**4.35**	7.95
U.S./Canadian dollar exchange rate *(US$)*	**0.643**	0.649	**0.635**	0.652

Natural gas prices showed improvements in the second quarter of 2002, compared with price levels experienced in the first three months of the year. However, throughout the first six months of the year prices remained well below the historically high levels experienced during the same period of 2001. Natural gas prices continue to be negatively impacted by higher than expected natural gas storage levels resulting from lower demand in the North American market. The AECO index price per thousand cubic feet averaged $4.42 in the second quarter and $3.88 for the year to date compared with $7.38 and $9.37 in the respective periods of 2001.

Although down from the prior year, world crude oil prices remained more resilient in the first half of 2002 than the prices for natural gas. The benchmark West Texas Intermediate ("WTI") crude oil price averaged US$26.27 per barrel in the second quarter and US$23.95 per barrel for the year to date, down six percent and 15 percent, respectively, from the same periods of 2001. The WTI price in the second quarter of 2002 showed improvements over the first quarter's average price of US$21.63 per barrel. Oil prices have continued to strengthen through 2002 due to the production management agreement between OPEC and non-OPEC producers, problems with Iraqi crude oil deliveries, the war on terrorism and indications that the world economy is turning around.

The differential between heavy and light crude oil prices has narrowed dramatically compared with last year largely due to improvements in the supply/demand balance for heavy oil. The WTI-Bow River differential averaged US$5.43 per barrel in the second quarter and US$5.33 in the six months ended June 2002, a significant improvement over the respective periods of 2001. The resumption of operations at the CITGO refinery in Illinois and the start of the summer asphalt season helped to maintain the low differential averages realized in the first quarter.

RESULTS OF OPERATIONS

Upstream – Onshore North America and Offshore and International

	Three Months Ended June 30							
	2002				2001			
Financial Results *($ millions)*	**Produced Gas and NGLs**	**Conventional Crude Oil**	**Syncrude**	**Total**	Produced Gas and NGLs	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	**$ 1,138**	**$ 618**	**$ 91**	**$ 1,847**	$ 715	$ 258	$ –	$ 973
Royalties and production taxes	**(174)**	**(107)**	**(1)**	**(282)**	(50)	(38)	–	(88)
	964	**511**	**90**	**1,565**	665	220	–	885
Expenses								
Transportation and selling	**85**	**22**	**1**	**108**	28	5	–	33
Operating	**122**	**130**	**68**	**320**	47	67	–	114
Depreciation, depletion and amortization	**–**	**–**	**–**	**543**	–	–	–	200
Upstream income	**$ 757**	**$ 359**	**$ 21**	**$ 594**	$ 590	$ 148	$ –	$ 538
Capital expenditures, excluding dispositions				**$ 1,319**				$ 404

Financial Results ($ millions)	Six Months Ended June 30 2002 Produced Gas and NGLs	Conventional Crude Oil	Syncrude	Total	2001 Produced Gas and NGLs	Conventional Crude Oil	Syncrude	Total
Revenues								
Gross revenue	**$ 1,538**	**$ 859**	**$ 91**	**$ 2,488**	$ 1,610	$ 520	$ –	$ 2,130
Royalties and production taxes	**(209)**	**(140)**	**(1)**	**(350)**	(119)	(63)	–	(182)
	1,329	**719**	**90**	**2,138**	1,491	457	–	1,948
Expenses								
Transportation and selling	**118**	**33**	**1**	**152**	55	18	–	73
Operating	**171**	**185**	**68**	**424**	86	131	–	217
Depreciation, depletion and amortization	**–**	**–**	**–**	**745**	–	–	–	363
Upstream income	**$ 1,040**	**$ 501**	**$ 21**	**$ 817**	$ 1,350	$ 308	$ –	$ 1,295
Capital expenditures, excluding dispositions				**$ 1,793**				$ 742

Revenue Variances for 2002 Compared to 2001 ($ millions)	Three Months Ended June 30 Price	Volume	Merger* Volume	Total	Six Months Ended June 30 Price	Volume	Merger* Volume	Total
Produced gas and NGLs	$ (201)	$ 39	$ 585	$ 423	$ (747)	$ 90	$ 585	$ (72)
Conventional crude oil	24	6	330	360	16	(7)	330	339
Syncrude	–	–	91	91	–	–	91	91
Total gross revenue	$ (177)	$ 45	$ 1,006	$ 874	$ (731)	$ 83	$ 1,006	$ 358

* Represents revenue from volumes added on account of the merger of the Company with AEC.

Revenues

In the second quarter, gross revenues of $1,847 million were up 90 percent, or $874 million, over the same quarter of 2001. Year-to-date gross revenues were $2,488 million, a 17 percent improvement over the same period last year. As part of the business combination, the fair value of $168 million relating to AEC's forward gas sales contracts for the period April 2002 to September 2002 was recorded and is being amortized over the contract period. In the second quarter, $77 million was recorded as additional gas revenue. For the purposes of discussing realized prices, this amount has been excluded.

Produced Gas and NGLs

Revenues from produced gas and natural gas liquids for the second quarter rose $423 million to $1,138 million compared with the second quarter of 2001. Produced gas sales volumes in the quarter were 1,524 million cubic feet per day higher than those of the same period in 2001, a 144 percent increase. Additional sales volumes resulting from the merger with AEC accounted for 96 percent of the increase, or 1,482 million cubic feet per day. The growth in natural gas sales volumes was partially offset by lower natural gas prices. Realized natural gas prices averaged $4.02 per thousand cubic feet in the three months ended June 2002 compared with $6.90 per thousand cubic feet in the same period of 2001. A loss from currency and commodity hedging activities in the quarter decreased natural gas revenues by $20 million, which contrasted with a $37 million increase in revenues in the same quarter last year.

For the year to date, revenues from produced gas and natural gas liquids were $1,538 million, a decline of four percent from the same period in 2001. The lower results primarily reflect the decrease in realized natural gas prices, which were down 51 percent to $3.89 per thousand cubic feet from the first half of last year. Natural gas sales volumes averaged 1,843 million cubic feet per day in the first six months of 2002, an increase of 801 million cubic feet per day over the same period of 2001, resulting primarily from the merger. Hedging activities in the first six months increased natural gas revenues by $9 million, an improvement over a hedging loss of $76 million for the same period last year.

Conventional Crude Oil

Conventional crude oil revenues increased 140 percent to $618 million in the second quarter of 2002 compared to the same quarter in 2001. Crude oil sales volumes averaged 214,870 barrels per day in the second quarter, an increase over 97,324 barrels per day in the same quarter of 2001. The merger of the Company with AEC resulted in an increase of 118,248 barrels per day in sales volumes for the quarter, approximately half of which, 58,384 barrels per day, related to Onshore North America crude. The remainder related to Offshore and International volumes, which increased by 59,864 barrels per day, reflecting the addition of the AEC Ecuador oil volumes. The Company's realized price from Onshore North America crude averaged $29.67 per barrel in the quarter, an improvement from $27.17 per barrel in the second quarter of 2001. Realized crude oil prices from the Company's Offshore and International crude averaged $32.48 in the quarter compared with $41.01 for the same period last year. Commodity and currency hedging in the quarter resulted in a $15 million loss, up from a $7 million loss in the respective period of 2001.

Compared with the first six months of 2001, revenues from conventional crude oil increased by 65 percent to $859 million. The higher gross revenues were chiefly attributable to the volumes added from the merger of the Company with AEC. Year-to-date realized crude oil prices from Onshore North America averaged $27.69 per barrel compared to $26.35 per barrel in the corresponding period of 2001. Offshore and International conventional crude oil activities had realized prices of $32.61 for the year to date compared with an average of $39.92 for the same period last year. Hedging activities for the six months ended June 2002 resulted in a hedging loss of $22 million, which compares to a hedging loss of $18 million in the first half of last year.

Syncrude

As a result of the merger, EnCana added Syncrude oil production to its Onshore North America upstream operating results. Syncrude sales in the quarter averaged 24,295 barrels per day at an average realized price of $40.09 per barrel. Syncrude sales volumes for the remainder of the year are expected to improve over the second quarter of the year when volume levels were negatively impacted by the coker turnaround.

Royalties and Production Taxes

Excluding the impact of hedging, royalties and production taxes increased to 15 percent of revenues compared to nine percent in the second quarter of last year. For the year to date, this rate was 14 percent compared to eight percent for the same period of 2001. The increase reflects the addition of AEC's production base, which decreases the Company's relative proportion of production attributable to fee land where only mineral taxes are due. The higher rate in 2002 also reflects an under-accrual of freehold mineral taxes at the year-end 2001.

Expenses

Transportation and selling costs for the quarter totalled $108 million compared with $33 million in the same quarter of 2001. For the year to date, these costs were $152 million, an increase of over $73 million in the six months ended June 2001. The higher transportation and selling costs are principally a result of the additional merger sales volumes in the quarter and year to date compared with the same periods last year. For the purpose of calculating the per-unit realized commodity prices used in the revenue variance discussion above, these costs have been netted against revenues.

Unit Operating Expenses* *($ per unit)*	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	**2002**	2001
Produced gas *(per thousand cubic feet)*	**$ 0.52**	$ 0.49	**$ 0.51**	$ 0.46
Conventional crude oil *(per barrel)*	**6.65**	7.42	**6.45**	7.23
Per barrel of oil equivalent**	**4.13**	4.33	**4.05**	4.17
Syncrude *(per barrel)*	**30.47**	–	**30.47**	–

* Excluding cost recoveries.

** Natural gas converted to barrel of oil equivalent at 6 thousand cubic feet = 1 barrel of oil equivalent.

Excluding Syncrude operations, upstream operating expenses in the quarter were $252 million, up $138 million from the same quarter of 2001. For the year to date, these expenses were $356 million compared with $217 million in the corresponding period last year. The higher expenses were mainly attributable to the additional production as a result of the merger with AEC. Per barrel of oil equivalent, conventional operating expenses decreased to $4.13 from $4.33 in the second quarter of 2001 and to $4.05 from $4.17 in the first six months of 2001. The improvements in unit operating expenses reflected the impact of lower costs associated with crude oil production.

For produced gas, unit operating costs were $0.52 per thousand cubic feet in the quarter compared with $0.49 per thousand cubic feet in the same period of 2001. For the year to date, these costs were $0.51 per thousand cubic feet, up from $0.46 per thousand cubic feet in the first half of last year. These increments in per-unit costs were mainly due to increased production levels from higher operating cost properties.

Unit operating costs for conventional crude oil dropped 10 percent in the quarter to $6.65 per barrel compared with the same quarter of 2001. This improvement reflects the combination of lower per unit operating costs related to the added AEC production and lower electricity costs in the second quarter of 2002 compared with 2001. For the year to date, operating costs were $6.45 per barrel compared to $7.23 per barrel for the same period last year.

Syncrude production added operating expenses of $68 million in the quarter and the year to date. Per-unit costs related to Syncrude production were higher than average in the second quarter as a result of the coker turnaround.

Depletion, depreciation and amortization charges amounted to $543 million in the quarter and $745 million for the year to date, increases of $343 million and $382 million over the respective periods last year. On a barrel of oil equivalent basis, depletion, depreciation and amortization expenses were 16 percent higher at $8.88 per barrel in the second quarter of 2002 relative to the same quarter of 2001. Year to date, these charges amounted to $8.45 per barrel compared to $6.95 per barrel in the first half of last year. The increases mainly reflect the additional charges associated with the AEC assets acquired.

Capital expenditures were $1,793 million in the first half of 2002 relative to $742 million spent in the first six months of 2001. $1,319 million of the year-to-date capital expenditures occurred in the second quarter of 2002, compared to $404 million in the same quarter last year. The increased level of spending reflects the additional cash flow generated from the acquired AEC operations. The majority of the year-to-date capital expenditures, 77 percent, were directed towards exploration and development in the Onshore North America division. The remaining 23 percent was primarily focused on high-impact exploration and development offshore of the East Coast of Canada, the Gulf of Mexico and Ecuador.

The Company drilled 560 net wells in the second quarter, 97 percent of which were successful. For the year to date, 1,054 net wells have been drilled at a 97 percent success rate.

Midstream and Marketing

Financial Results* *($ millions)*	Three Months Ended June 30		Six Months Ended June 30	
	2002	2001	**2002**	2001
Revenues	**$ 1,108**	$ 235	**$ 1,600**	$ 846
Expenses				
Transportation and selling	**50**	4	**55**	9
Operating	**138**	48	**205**	154
Purchased product	**854**	164	**1,234**	641
Depreciation and amortization	**25**	4	**31**	7
	$ 41	$ 15	**$ 75**	$ 35
Capital expenditures, excluding dispositions	**$ 120**	$ 43	**$ 124**	$ 69

* Results of the Midstream and Marketing segment exclude the discontinued operations as described in Note 5 to the Consolidated Financial Statements.

Midstream revenues from continuing operations were $174 million in the three months ended June 2002 and $260 million for the year to date, showing improvements of $118 million and $90 million over the respective periods of 2001. The increases were chiefly attributable to the addition of the AEC midstream assets, which include gas storage facilities, natural gas processing, and pipeline operations, to the Company's existing midstream segment.

The Company's Marketing activity produced a margin from continuing operations of $39 million in the second quarter, up from $6 million in 2001. In the year to date, Marketing activity from continuing operations resulted in a margin of $54 million, an increase of $37 million from the prior year. The increase is primarily due to the additional AEC purchased gas activity resulting from the merger.

Depreciation and amortization expenses were $25 million in the second quarter, up from $4 million in the same quarter last year. Year-to-date charges amounted to $31 million compared with $7 million in the first half of 2001. The increase in depreciation and amortization expenses primarily reflects the increase in the segment asset base as a result of AEC's midstream assets.

Capital expenditures were $120 million in the second quarter, up from $43 million in the same quarter last year. For the first half of the year, capital expenditures were also higher at $124 million compared to $69 million in the same period of 2001. The 2002 expenditures related primarily to ongoing improvements to midstream facilities. Capital expenditures in the first six months of 2001 were principally due to the construction of two power plants in Alberta.

Corporate

Administrative expenses amounted to $44 million in the second quarter of 2002 up from $21 million in the same period of 2001. Year-to-date administrative expenses were $61 million compared to $41 million for the same period last year. This increase is attributed to the merger of the Company with AEC in the second quarter.

Compared with 2001, net interest expense was up $97 million to $103 million in the quarter and $111 million to $130 million in the six months ended June 2002. The higher net interest expense primarily reflects the higher debt level as a result of the merger with AEC and the issuance of U.S. dollar notes in the fourth quarter of 2001 as well as lower cash levels in 2002.

In the second quarter of 2002, foreign exchange resulted in a gain of $170 million compared with a gain of $26 million in the same quarter of 2001. For the year to date, the total gain resulting from foreign exchange was $180 million, which compares to $3 million for the same period last year. The majority of the foreign exchange impact results from the translation of U.S. dollar denominated debt where exchange gains and losses are recorded in earnings in the period they arise.

In conjunction with the merger, in the second quarter the Company reviewed its accounting for operations outside of Canada and determined that all such operations are self-sustaining. Previously, all such operations had been considered to be integrated and as such were accounted for using the temporal method of translation. This change in classification resulted in a change to the current rate method of translation, which is used for self-sustaining operations and is described in Note 2 of the Consolidated Financial Statements. This change was adopted prospectively as of April 5, 2002 and resulted in a decrease in net earnings of $5 million in the second quarter of 2002.

The provision for income taxes in the second quarter was $155 million, up from $112 million in the same quarter of last year due to higher operating results. For the year to date, the provision for income taxes was $237 million, down $146 million, or 38 percent, from the first six months of 2001. The decrease reflects the impact of lower year-to-date operating results combined with an approximately $40 million reduction to future taxes resulting from a reduction in the Alberta corporate tax rate. The effective tax rate for 2002 is expected to be 34 to 36 percent.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from continuing operations was $916 million in the second quarter and $1,303 million for the year to date. In comparison, cash flow from continuing operations for the same periods of 2001 were $601 million and $1,313 million, respectively. Weaker energy prices in 2002 were the primary factors contributing to the year-to-date decline, which was offset in the second quarter by the added cash flow from continuing operations resulting from the merger of the Company with AEC.

Net capital expenditures of $1,206 million in the quarter, and $1,684 million for the year to date, include approximately $420 million related to the purchase of certain Colorado natural gas properties from subsidiaries of El Paso Corporation. This compares with net capital expenditures of $424 million in the second quarter of 2001 and $649 million for the six months ended June 30, 2001, which included the sale of PanCanadian's Pelican Lake operations in the first quarter. The Company's net investing for the year to date was funded by cash flow of $1,327 million and long-term debt.

EnCana's net debt increased to $8,223 million from $2,303 million at year-end 2001, primarily as a result of the merger with AEC. Net debt to capitalization, including all preferred securities as debt, was 39 percent, up slightly from 37 percent at December 31, 2001.

RISK MANAGEMENT

Through the normal course of business, the Company is exposed to market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit and operational risks.

Exposure to market risks is managed by the Company through the use of various financial instruments and contracts. This risk management program is designed to enhance shareholder value by mitigating the volatility associated with commodity prices, exchange rates and interest rates, enhancing the probability of achieving corporate performance targets and locking in desirable rates of return on specific projects.

As a means of managing commodity price volatility, the Company had the following agreements in place as at June 30, 2002:

Produced Gas

- At June 30, 2002 the contracts related to produced gas had a total unrecognized gain of $165 million, the details of which are outlined below.
- Approximately 305 million cubic feet per day of natural gas sold forward at an average AECO equivalent of $3.78 per thousand cubic feet for the period to September 2002. The contracts had an unrecognized gain of $3 million at June 30, 2002.
- Approximately 570 million cubic feet per day of natural gas under derivative contracts at an average AECO equivalent of $4.43 per thousand cubic feet for the period to October 2002. The contracts had an unrecognized gain of $55 million at June 30, 2002.
- Approximately 42 million cubic feet per day of natural gas sold forward at an average Nymex equivalent of US$3.47 per thousand cubic feet for the period to October 2002. The contracts had an unrecognized gain of $3 million at June 30, 2002.
- Approximately 163 million cubic feet per day of natural gas under derivative contracts at an average Nymex equivalent of US$3.30 per thousand cubic feet for the period to October 2002. The contracts had an unrecognized gain of $3 million at June 30, 2002.
- Approximately 236 million cubic feet per day of natural gas sold forward at an average Rockies equivalent of US$2.35 per thousand cubic feet for the period to September 2002. The contracts had an unrecognized gain of $19 million at June 30, 2002.
- Approximately 131 million cubic feet per day of natural gas under derivative contracts at an average Rockies equivalent of US$2.41 per thousand cubic feet for the period to September 2002. The contracts had an unrecognized gain of $12 million at June 30, 2002.
- Approximately 99 million cubic feet per day of Rockies natural gas sold forward to October 2002 and approximately 155 million cubic feet per day for the period November 2002 to October 2007 at a fixed differential of Nymex less US$0.43 per thousand cubic feet. These contracts had an unrecognized gain of $47 million at June 30, 2002.
- Approximately 20 million cubic feet per day of Rockies natural gas under derivative contracts to October 2002 and 79 million cubic feet per day for the period November 2002 to October 2007 at a fixed differential of Nymex less US$0.39 per thousand cubic feet. These contracts had an unrecognized gain of $20 million at June 30, 2002.
- Approximately 116 million cubic feet per day of natural gas call options were sold for the period to October 2002 at an average strike price of $6.20 per thousand cubic feet. The unrecognized gain on the options at June 30, 2002 was $3 million.

The above contracts exclude the mark-to-market adjustment recorded in the purchase equation relating to those contracts acquired in the merger with AEC.

Crude Oil

- Approximately 50,000 barrels per day of crude oil costless collars for the period to December 2002. The contracts had an unrecognized loss of $8 million at June 30, 2002.
- Approximately 35,000 barrels per day of crude oil put options for the period to December 2002 at a price of US$20.00 per barrel. At June 30, 2002 these contracts had an unrecognized loss of $5 million.

Purchased Gas

- As part of the Marketing business, the Company has entered into contracts to purchase and sell physical volumes of natural gas for the period to October 2003. Certain of these volumes were purchased at fixed prices and sold at index and subsequently fixed by financial swaps. These transactions are matched thereby creating a closed combined physical and financial position. On a combined basis these contracts had an unrecognized $29 million gain at June 30, 2002.

Storage Optimization

- Various financial instruments have been entered into for the next 10 months to manage price volatility relating to the gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. On a combined basis, these instruments had a net unrecognized loss of $2 million at June 30, 2002.

As a means of managing the exposure to fluctuations in the U.S. to Canadian exchange rate, the Company has entered into foreign exchange contracts in the amount of US$748 million at an average exchange rate of US$ 0.719 for the period to June 2004. The unrecognized loss with respect to these contracts was $102 million at June 30, 2002.

The Company has entered into various interest rate and cross currency interest rate swap transactions as a means of managing the interest rate exposure on debt instruments. The unrealized gain with respect to these transactions was $60 million at June 30, 2002.

The risk of credit losses is minimized through the use of mandated credit policies and procedures designed to limit exposures within acceptable levels. EnCana does not have a significant concentration of credit risk with any single counterpart and bad debts incurred or provided for to date in 2002 are not material.

Operational risks are managed through a comprehensive insurance program designed to protect the Company from any significant losses arising from the risk exposures. Safety and environment risks are managed by executing policies and standards that comply with or exceed government regulations and industry standards. In addition, the Company maintains a system that identifies, assesses and controls safety and environmental risk and requires regular reporting to senior management and the Board of Directors.

OUTLOOK

The Company continues to be optimistic about results for the remainder of 2002. Sales for 2002 are forecast to be between 2,270 and 2,340 million cubic feet per day (2,675 to 2,745 million cubic feet per day pro forma) for produced natural gas and between 213,000 and 232,000 barrels per day (245,000 to 264,000 barrels per day pro forma) of oil and natural gas liquids. The pricing environment is expected to remain volatile. However, continued weakness in North American gas supply along with effective management of OPEC crude production should help in firming energy prices. The Company's hedging program is expected to assist in reducing the negative effect of any market price declines.

Capital investment in core programs is expected to be approximately $4.2 billion ($5.0 billion pro forma) before acquisitions and dispositions. It is expected that the Company will be able to fund this program largely from cash flow together with proceeds received on the disposition of non-core assets. Expenditures will continue to emphasize strong near-term production growth, particularly in natural gas, while developing offshore and international projects for medium and longer-term value creation.

EnCana Corporation

Consolidated Statement of Earnings

(unaudited) ($ millions, except per share amounts)		June 30 Three Months Ended 2002	2001	Six Months Ended 2002	2001
Revenues, Net of Royalties and Production Taxes	*(note 4)*	**$ 2,676**	$ 1,136	**$ 3,737**	$ 2,811
Expenses	*(note 4)*				
Transportation and selling		**158**	37	**207**	82
Operating		**458**	162	**629**	371
Purchased product		**854**	164	**1,234**	641
Administrative		**44**	21	**61**	41
Interest, net		**103**	6	**130**	19
Foreign exchange	*(note 7)*	**(170)**	(26)	**(180)**	(3)
Depreciation, depletion and amortization		**580**	215	**794**	389
		2,027	579	**2,875**	1,540
Net Earnings Before the Undernoted		**649**	557	**862**	1,271
Income tax expense	*(note 6)*	**155**	112	**237**	383
Net Earnings from Continuing Operations		**494**	445	**625**	888
Net Earnings from Discontinued Operations	*(note 5)*	**(36)**	14	**(34)**	34
Net Earnings		**$ 458**	$ 459	**$ 591**	$ 922
Earnings per Common Share	*(note 9)*				
Net Earnings from Continuing Operations					
Basic		**$ 1.07**	$ 1.74	**$ 1.74**	$ 3.47
Diluted		**$ 1.05**	$ 1.70	**$ 1.71**	$ 3.39
Net Earnings					
Basic		**$ 0.99**	$ 1.79	**$ 1.65**	$ 3.60
Diluted		**$ 0.97**	$ 1.75	**$ 1.62**	$ 3.52

Consolidated Statement of Retained Earnings

(unaudited) ($ millions)		Six Months Ended June 30 2002	2001
Retained Earnings, Beginning of Year			
As previously reported		**$ 3,689**	$ 3,721
Retroactive adjustment for change in accounting policy	*(note 2)*	**(59)**	(42)
As restated		**3,630**	3,679
Net Earnings		**591**	922
Dividends on Common Shares and Other Distributions, net of tax		**(74)**	(53)
Other Adjustments		**–**	(50)
Retained Earnings, End of Period		**$ 4,147**	$ 4,498

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Consolidated Balance Sheet

(unaudited) ($ millions)		As at June 30, 2002	As at December 31, 2001
Assets			
Current Assets			
Cash and cash equivalents		$ 166	$ 963
Accounts receivable and accrued revenue		1,464	623
Inventories		518	87
		2,148	1,673
Capital Assets, net	*(note 4)*	22,140	8,162
Investments and Other Assets		441	237
Assets of Discontinued Operations	*(note 5)*	1,673	728
Goodwill	*(note 3)*	3,077	–
	(note 4)	$ 29,479	$ 10,800
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable		$ 1,758	$ 824
Income tax payable		405	656
Current portion of long-term debt	*(note 7)*	108	160
		2,271	1,640
Long-Term Debt	*(note 7)*	7,525	2,210
Deferred Credits and Other Liabilities		530	325
Future Income Taxes		4,679	2,060
Liabilities of Discontinued Operations	*(note 5)*	1,065	586
Preferred Securities of Subsidiary		449	–
		16,519	6,821
Shareholders' Equity			
Preferred securities		126	126
Share capital	*(note 8)*	8,662	196
Fair value of options acquired to purchase common shares	*(note 3)*	154	–
Paid in surplus		40	27
Retained earnings		4,147	3,630
Foreign currency translation adjustment	*(note 2)*	(169)	–
		12,960	3,979
		$ 29,479	$ 10,800

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Consolidated Statement of Cash Flows

		June 30			
		Three Months Ended		Six Months Ended	
(unaudited) ($ millions, except per share amounts)		**2002**	2001	**2002**	2001
Operating Activities					
Net earnings		**$ 494**	$ 445	**$ 625**	$ 888
Depletion, depreciation and amortization		**580**	215	**794**	389
Future income taxes		**99**	(26)	**141**	50
Other		**(257)**	(33)	**(257)**	(14)
Cash flow from continuing operations		**916**	601	**1,303**	1,313
Cash flow from discontinued operations	*(note 5)*	**22**	21	**24**	47
Cash flow		**938**	622	**1,327**	1,360
Net change in non-cash working capital from continuing operations		**(200)**	216	**(468)**	358
Net change in non-cash working capital from discontinued operations		**(54)**	(164)	**(1)**	(51)
		684	674	**858**	1,667
Investing Activities					
Business combination	*(note 3)*	**(128)**	–	**(128)**	–
Capital expenditures	*(note 4)*	**(1,446)**	(454)	**(1,927)**	(831)
Proceeds on disposal of assets		**240**	30	**243**	182
Net change in investments and other		**4**	12	**(13)**	5
Net change in non-cash working capital from continuing operations		**(219)**	–	**(250)**	(75)
Discontinued operations		**(12)**	6	**(12)**	9
		(1,561)	(406)	**(2,087)**	(710)
Financing Activities					
Repayment of short-term financing		**–**	–	**–**	(250)
Issuance of long-term debt		**649**	–	**649**	94
Repayment of long-term debt		**(77)**	(94)	**(157)**	(249)
Issuance of common shares		**51**	9	**69**	33
Dividends on common shares		**(48)**	(25)	**(73)**	(51)
Payments to preferred securities holders		**(7)**	(2)	**(7)**	(4)
Net change in non-cash working capital from continuing operations		**2**	3	**(1)**	1
Discontinued operations		**(5)**	–	**(5)**	–
Other		**(32)**	–	**(32)**	–
		533	(109)	**443**	(426)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(9)**	(13)	**(11)**	9
Increase (Decrease) in Cash and Cash Equivalents		**(353)**	146	**(797)**	540
Cash and Cash Equivalents, Beginning of Period		**519**	591	**963**	197
Cash and Cash Equivalents, End of Period		**$ 166**	$ 737	**$ 166**	$ 737
Cash Flow per Common Share					
Basic		**$ 2.03**	$ 2.43	**$ 3.70**	$ 5.32
Diluted		**$ 2.00**	$ 2.38	**$ 3.64**	$ 5.21

See accompanying notes to Consolidated Financial Statements.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

1. BASIS OF PRESENTATION

The interim consolidated financial statements include the accounts of EnCana Corporation (formerly PanCanadian Energy Corporation) ("PanCanadian") and its subsidiaries (the "Company"), and are presented in accordance with Canadian generally accepted accounting principles. The Company is in the business of exploration, production and marketing of natural gas and crude oil, as well as pipelines, natural gas liquids processing and gas storage 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, 2001, except as described in Note 2. 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, 2001.

2. CHANGES IN ACCOUNTING POLICIES

Foreign Currency Translation

At January 1, 2002, the Company retroactively adopted amendments to the Canadian accounting standard for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items, that do not qualify for hedge accounting, are recorded in earnings as they arise. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. As required by the standard, all prior periods have been restated for the change in accounting policy. The change results in an increase to net earnings of $81 million for 2002 (2001 – decrease of $2 million). The effect of this change on the December 31, 2001 consolidated balance sheet is an increase in long-term debt and a reduction in deferred credits of $92 million, as well as a reduction in deferred charges and retained earnings of $59 million.

As a result of the business combination described in Note 3, the Company reviewed its accounting for operations outside of Canada and determined that all such operations are self-sustaining. The accounts of self-sustaining foreign subsidiaries are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the subsidiaries are deferred and included as a separate component of shareholders' equity. Previously, operations outside of Canada were considered to be integrated and translated using the temporal method. Under the temporal method, monetary assets and liabilities were translated at the period-end exchange rate, other assets and liabilities at the historical rates and revenues and expenses at the average monthly rates except depreciation and depletion, which were translated on the same basis as the related assets.

This change was adopted prospectively beginning April 5, 2002, and results in a decrease in net earnings of $5 million for the second quarter of 2002.

3. BUSINESS COMBINATION

On January 27, 2002, PanCanadian and Alberta Energy Company Ltd. ("AEC") announced plans to combine their companies. The transaction was accomplished through a plan of arrangement (the "Arrangement") under the *Business Corporations Act* (Alberta). The Arrangement included a common share exchange, pursuant to which holders of common shares of AEC received 1.472 common shares of PanCanadian for each common share of AEC that they held. After obtaining approvals of the common shareholders and optionholders of AEC and the common shareholders of PanCanadian, the Court of Queen's Bench of Alberta and appropriate regulatory and other authorities, the transaction closed April 5, 2002, and PanCanadian changed its name to EnCana Corporation ("EnCana").

This business combination has been accounted for using the purchase method with the results of operations of AEC included in the consolidated financial statements from the date of acquisition. The Arrangement resulted in PanCanadian issuing 218.5 million common shares and a transaction value of $8,714 million.

The calculation of the purchase price and the preliminary allocation to assets and liabilities acquired as of April 5, 2002 is shown below. The purchase price and goodwill allocation is preliminary because certain items such as the determination of the final tax bases and fair values of the assets and liabilities as of the acquisition date have not been completed. Further information related to AEC can be obtained from the audited consolidated financial statements included in the Joint Information Circular concerning the merger of AEC and PanCanadian.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

3. BUSINESS COMBINATION (continued)

		($ millions)
Calculation of Purchase Price:		
Common shares issued to AEC shareholders *(millions)*	218.5	
Price of Common Shares *($ per common share)*	38.43	
Value of Common Shares issued		$ 8,397
Fair value of AEC share options exchanged for share options of EnCana Corporation		167
Transaction costs		150
Total purchase price		8,714
Plus: Fair value of liabilities assumed		
Current liabilities		1,781
Long-term debt		4,393
Project financing debt		604
Preferred securities		458
Capital securities		450
Other non-current liabilities		193
Future income taxes		2,647
Total Purchase Price and Liabilities Assumed		$ 19,240

	($ millions)
Fair Value of Assets Acquired:	
Current assets	$ 1,505
Capital assets	14,053
Other non-current assets	605
Goodwill	3,077
Total Fair Value of Assets Acquired	$ 19,240

4. SEGMENTED INFORMATION

Due to the business combination as described in Note 3, the Company has redefined its operations into the following segments. Onshore North America includes the Company's North America onshore exploration for, and production of, natural gas and crude oil. Offshore and International combines the Offshore and International Operations Division exploration for, and production of, crude oil and natural gas in Ecuador, the Canadian East Coast, Gulf of Mexico and the U.K. North Sea with the Offshore and New Ventures Exploration Division exploration activity on the Canadian East Coast, the North America frontier region, the Gulf of Mexico, the U.K. North Sea and Latin America. Midstream and Marketing includes pipelines, natural gas liquids processing and gas storage operations, as well as ancillary activities related to the marketing of the Company's natural gas and crude oil production. All prior periods have been restated to conform to these definitions. Operations that have been discontinued are disclosed in Note 5.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the Three Months Ended June 30)

	Onshore North America		Offshore and International		Midstream and Marketing	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 1,620**	$ 932	**$ 227**	$ 41	**$ 1,108**	$ 235
Royalties and production taxes	**223**	88	**59**	–	**–**	–
Revenues, net of royalties and production taxes	**1,397**	844	**168**	41	**1,108**	235
Expenses						
Transportation and selling	**93**	29	**15**	4	**50**	4
Operating	**274**	112	**46**	2	**138**	48
Purchased product	**–**	–	**–**	–	**854**	164
Depreciation, depletion and amortization	**481**	185	**62**	15	**25**	4
Segment income	**$ 549**	$ 518	**$ 45**	$ 20	**$ 41**	$ 15

	Corporate		Consolidated	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 3**	$ 16	**$ 2,958**	$ 1,224
Royalties and production taxes	**–**	–	**282**	88
Revenues, net of royalties and production taxes	**3**	16	**2,676**	1,136
Expenses				
Transportation and selling	**–**	–	**158**	37
Operating	**–**	–	**458**	162
Purchased product	**–**	–	**854**	164
Depreciation, depletion and amortization	**12**	11	**580**	215
Segment income	**(9)**	5	**626**	558
Administrative	**44**	21	**44**	21
Interest, net	**103**	6	**103**	6
Foreign exchange	**(170)**	(26)	**(170)**	(26)
	(23)	1	**(23)**	1
Net Earnings Before Income Tax	**14**	4	**649**	557
Income tax expense	**155**	112	**155**	112
Net Earnings from Continuing Operations	**$ (141)**	$ (108)	**$ 494**	$ 445

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Geographic and Product Information (For the Three Months Ended June 30)

ONSHORE NORTH AMERICA

	Produced Gas and NGLs			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 956**	$ 687	**$ 175**	$ 24
Royalties and production taxes	**132**	40	**42**	10
Revenues, net of royalties and production taxes	**824**	647	**133**	14
Expenses				
Transportation and selling	**57**	24	**25**	–
Operating	**107**	44	**15**	3
Operating Cash Flow	**$ 660**	$ 579	**$ 93**	$ 11

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 398**	$ 221	**$ 91**	$ –	**$ 1,620**	$ 932
Royalties and production taxes	**48**	38	**1**	–	**223**	88
Revenues, net of royalties and production taxes	**350**	183	**90**	–	**1,397**	844
Expenses						
Transportation and selling	**10**	5	**1**	–	**93**	29
Operating	**84**	65	**68**	–	**274**	112
Operating Cash Flow	**$ 256**	$ 113	**$ 21**	$ –	**$ 1,030**	$ 703

OFFSHORE AND INTERNATIONAL

	Ecuador		U.K. North Sea		Other Countries		Total Offshore and International	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001
Revenues								
Gross revenue	**$ 182**	$ –	**$ 45**	$ 41	**$ –**	$ –	**$ 227**	$ 41
Royalties and production taxes	**59**	–	**–**	–	**–**	–	**59**	–
Revenues, net of royalties and production taxes	**123**	–	**45**	41	**–**	–	**168**	41
Expenses								
Transportation and selling	**10**	–	**5**	4	**–**	–	**15**	4
Operating	**31**	–	**3**	2	**12**	–	**46**	2
Operating Cash Flow	**$ 82**	$ –	**$ 37**	$ 35	**$ (12)**	$ –	**$ 107**	$ 35

MIDSTREAM AND MARKETING

	Midstream		Marketing		Total Midstream and Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 174**	$ 56	**$ 934**	$ 179	**$ 1,108**	$ 235
Expenses						
Transportation and selling	**–**	–	**50**	4	**50**	4
Operating	**96**	43	**42**	5	**138**	48
Purchased product	**51**	–	**803**	164	**854**	164
Operating Cash Flow	**$ 27**	$ 13	**$ 39**	$ 6	**$ 66**	$ 19

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Results of Operations (For the Six Months Ended June 30)

($ millions)	Onshore North America 2002	Onshore North America 2001	Offshore and International 2002	Offshore and International 2001	Midstream and Marketing 2002	Midstream and Marketing 2001
Revenues						
Gross revenue	**$ 2,217**	$ 2,043	**$ 271**	$ 87	**$ 1,600**	$ 846
Royalties and production taxes	**291**	182	**59**	–	**–**	–
Revenues, net of royalties and production taxes	**1,926**	1,861	**212**	87	**1,600**	846
Expenses						
Transportation and selling	**132**	64	**20**	9	**55**	9
Operating	**375**	210	**49**	7	**205**	154
Purchased product	**–**	–	**–**	–	**1,234**	641
Depreciation, depletion and amortization	**671**	330	**74**	33	**31**	7
Segment income	**$ 748**	$ 1,257	**$ 69**	$ 38	**$ 75**	$ 35

	Corporate 2002	Corporate 2001	Consolidated 2002	Consolidated 2001
Revenues				
Gross revenue	**$ (1)**	$ 17	**$ 4,087**	$ 2,993
Royalties and production taxes	**–**	–	**350**	182
Revenues, net of royalties and production taxes	**(1)**	17	**3,737**	2,811
Expenses				
Transportation and selling	**–**	–	**207**	82
Operating	**–**	–	**629**	371
Purchased product	**–**	–	**1,234**	641
Depreciation, depletion and amortization	**18**	19	**794**	389
Segment income	**(19)**	(2)	**873**	1,328
Administrative	**61**	41	**61**	41
Interest, net	**130**	19	**130**	19
Foreign exchange	**(180)**	(3)	**(180)**	(3)
	11	57	**11**	57
Net Earnings Before Income Tax	**(30)**	(59)	**862**	1,271
Income tax expense	**237**	383	**237**	383
Net Earnings from Continuing Operations	**$ (267)**	$ (442)	**$ 625**	$ 888

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Geographic and Product Information (For the Six Months Ended June 30)

ONSHORE NORTH AMERICA

	Produced Gas and NGLs			
	Canada		U.S. Rockies	
	2002	2001	**2002**	2001
Revenues				
Gross revenue	**$ 1,316**	$ 1,539	**$ 207**	$ 63
Royalties and production taxes	**160**	94	**49**	25
Revenues, net of royalties and production taxes	**1,156**	1,445	**158**	38
Expenses				
Transportation and selling	**88**	51	**25**	–
Operating	**151**	80	**20**	6
Operating Cash Flow	**$ 917**	$ 1,314	**$ 113**	$ 32

	Conventional Crude Oil		Syncrude		Total Onshore North America	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 603**	$ 441	**$ 91**	$ –	**$ 2,217**	$ 2,043
Royalties and production taxes	**81**	63	**1**	–	**291**	182
Revenues, net of royalties and production taxes	**522**	378	**90**	–	**1,926**	1,861
Expenses						
Transportation and selling	**18**	13	**1**	–	**132**	64
Operating	**136**	124	**68**	–	**375**	210
Operating Cash Flow	**$ 368**	$ 241	**$ 21**	$ –	**$ 1,419**	$ 1,587

OFFSHORE AND INTERNATIONAL

	Ecuador		U.K. North Sea		Other Countries		Total Offshore and International	
	2002	2001	**2002**	2001	**2002**	2001	**2002**	2001
Revenues								
Gross revenue	**$ 182**	$ –	**$ 89**	$ 87	**$ –**	$ –	**$ 271**	$ 87
Royalties and production taxes	**59**	–	**–**	–	**–**	–	**59**	–
Revenues, net of royalties and production taxes	**123**	–	**89**	87	**–**	–	**212**	87
Expenses								
Transportation and selling	**10**	–	**10**	9	**–**	–	**20**	9
Operating	**31**	–	**6**	7	**12**	–	**49**	7
Operating Cash Flow	**$ 82**	$ –	**$ 73**	$ 71	**$ (12)**	$ –	**$ 143**	$ 71

MIDSTREAM AND MARKETING

	Midstream		Marketing		Total Midstream and Marketing	
	2002	2001	**2002**	2001	**2002**	2001
Revenues						
Gross revenue	**$ 260**	$ 170	**$ 1,340**	$ 676	**$ 1,600**	$ 846
Expenses						
Transportation and selling	**–**	–	**55**	9	**55**	9
Operating	**157**	145	**48**	9	**205**	154
Purchased product	**51**	–	**1,183**	641	**1,234**	641
Operating Cash Flow	**$ 52**	$ 25	**$ 54**	$ 17	**$ 106**	$ 42

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

4. SEGMENTED INFORMATION (continued)

Capital Expenditures

	Three Months Capital Expenditures		Six Months Capital Expenditures	
	2002	2001	**2002**	2001
Onshore North America	**$ 1,043**	$ 302	**$ 1,384**	$ 606
Offshore and International	**276**	102	**409**	136
Midstream and Marketing	**120**	43	**124**	69
Corporate	**7**	7	**10**	20
Total	**$ 1,446**	$ 454	**$ 1,927**	$ 831

Capital and Total Assets

	As at			
	Capital Assets		Total Assets	
	June 30, 2002	December 31, 2001	**June 30, 2002**	December 31, 2001
Onshore North America	**$ 18,207**	$ 6,552	**$ 19,820**	$ 7,080
Offshore and International	**2,753**	1,018	**3,016**	1,111
Midstream and Marketing	**968**	426	**1,490**	817
Corporate (including unallocated Goodwill)	**212**	166	**3,370**	1,064
Assets of Discontinued Operations	**–**	–	**1,783**	728
Total	**$ 22,140**	$ 8,162	**$ 29,479**	$ 10,800

5. DISCONTINUED OPERATIONS

On April 24, 2002, the Company adopted formal plans to exit from the Houston-based merchant energy operation, which was included in the Midstream and Marketing segment. Accordingly, these operations have been accounted for as discontinued operations.

On July 9, 2002, the Company announced that it plans to sell its 70 percent equity investment in the Cold Lake Pipeline System and its 100 percent interest in the Express Pipeline System. Both crude oil pipeline systems were acquired in the business combination with AEC on April 5, 2002 described in Note 3. Accordingly, these operations have been accounted for as discontinued operations. The Company, through indirect wholly owned subsidiaries, is a shipper on the Express system. The financial results shown below include tariff revenue of $23 million paid by the Company for services on Express.

The following tables present the effect of the discontinued operations on the consolidated financial statements:

CONSOLIDATED STATEMENT OF INCOME

	For the three months ended June 30					
	Merchant Energy		Midstream – Pipelines		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues	**$ 563**	$ 1,045	**$ 58**	$ –	**$ 621**	$ 1,045
Expenses						
Operating	**–**	–	**20**	–	**20**	–
Purchased product	**580**	1,013	**–**	–	**580**	1,013
Administrative	**8**	8	**–**	–	**8**	8
Interest, net	**–**	–	**11**	–	**11**	–
Foreign exchange	**–**	–	**(10)**	–	**(10)**	–
Depletion, depreciation and amortization	**1**	1	**11**	–	**12**	1
Loss on discontinuance	**53**	–	**–**	–	**53**	–
	642	1,022	**32**	–	**674**	1,022
Net Earnings (Loss) Before Income Tax	**(79)**	23	**26**	–	**(53)**	23
Income tax expense (recovery)	**(28)**	9	**11**	–	**(17)**	9
Net Earnings (Loss) from Discontinued Operations	**$ (51)**	$ 14	**$ 15**	$ –	**$ (36)**	$ 14

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

5. DISCONTINUED OPERATIONS (continued)

CONSOLIDATED STATEMENT OF INCOME

	For the six months ended June 30					
	Merchant Energy		Midstream – Pipelines*		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Revenues	**$ 1,309**	$ 2,567	**$ 58**	$ –	**$ 1,367**	$ 2,567
Expenses						
Operating	**–**	–	**20**	–	**20**	–
Purchased product	**1,313**	2,495	**–**	–	**1,313**	2,495
Administrative	**18**	15	**–**	–	**18**	15
Interest, net	**–**	–	**11**	–	**11**	–
Foreign exchange	**–**	–	**(10)**	–	**(10)**	–
Depletion, depreciation and amortization	**1**	2	**11**	–	**12**	2
Loss on discontinuance	**53**	–	**–**	–	**53**	–
	1,385	2,512	**32**	–	**1,417**	2,512
Net Earnings (Loss) Before Income Tax	**(76)**	55	**26**	–	**(50)**	55
Income tax expense (recovery)	**(27)**	21	**11**	–	**(16)**	21
Net Earnings (Loss) from Discontinued Operations	**$ (49)**	$ 34	**$ 15**	$ –	**$ (34)**	$ 34

* Reflects only three months of earnings as EnCana did not own the pipelines until April 5, 2002.

CONSOLIDATED BALANCE SHEET

	As at June 30					
	Merchant Energy		Midstream – Pipelines		Total	
($ millions)	**2002**	2001	**2002**	2001	**2002**	2001
Assets						
Cash and cash equivalents	**$ –**	$ –	**$ 66**	$ –	**$ 66**	$ –
Accounts receivable and accrued revenue	**338**	1,314	**44**	–	**382**	1,314
Inventories	**–**	9	**1**	–	**1**	9
	338	1,323	**111**	–	**449**	1,323
Capital assets, net	**–**	8	**807**	–	**807**	8
Investments and other assets	**–**	17	**417**	–	**417**	17
	338	1,348	**1,335**	–	**1,673**	1,348
Liabilities						
Accounts payable and accrued liabilities	**240**	1,202	**68**	–	**308**	1,202
Income tax payable	**–**	–	**4**	–	**4**	–
Current portion of long-term debt	**–**	–	**23**	–	**23**	–
	240	1,202	**95**	–	**335**	1,202
Long-term debt	**–**	–	**567**	–	**567**	–
Future income taxes	**–**	–	**163**	–	**163**	–
	240	1,202	**825**	–	**1,065**	1,202
Net Assets of Discontinued Operations	**$ 98**	$ 146	**$ 510**	$ –	**$ 608**	$ 146

Notes to Consolidated Financial Statements *(Unaudited)*

5. DISCONTINUED OPERATIONS (continued)

For comparative purposes, the following tables present the effect of only the Merchant Energy Discontinued Operations on the Consolidated Financial Statements for the years ended December 31. It does not include any financial information related to Midstream – Pipelines as EnCana did not own the pipelines being discontinued at that time.

CONSOLIDATED STATEMENT OF INCOME

($ millions)	Year Ended December 31 2001	2000
Revenues	**$ 4,085***	$ 3,025
Expenses		
Purchased product	**3,983***	2,961
Administrative	**43**	26
Depletion, depreciation and amortization	**4**	3
	4,030	2,990
Net Earnings Before Income Tax	**55**	35
Income tax expense	**22**	13
Net Earnings from Discontinued Operations	**$ 33**	$ 22

* Upon review of additional information related to 2001 sales and purchases of natural gas by the U.S. marketing subsidiary, the Company has determined certain revenue and expenses should have been reflected in the financial statements on a net basis rather than included on a gross basis as Revenue and Expenses – Purchased product. The amendment had no effect on net earnings or cash flow but Revenues and Expenses – Purchased product have been reduced by $1,126 million.

CONSOLIDATED BALANCE SHEET

($ millions)	As at December 31 2001	2000
Assets		
Accounts receivable and accrued revenue	**$ 323**	$ 699
Risk management assets	**309**	–
Inventories	**70**	2
	702	701
Capital assets, net	**9**	3
Deferred charges and other assets	**17**	32
	728	736
Liabilities		
Accounts payable and accrued liabilities	**306**	631
Risk management liabilities	**278**	–
	584	631
Deferred credits and liabilities	**2**	3
	586	634
Net Assets of Discontinued Operations	**$ 142**	$ 102

CONSOLIDATED STATEMENT OF CASH FLOWS

($ millions)	Year Ended December 31 2001	2000
Operating Activities		
Cash flow	**$ 47**	$ 26
Net change in non-cash working capital	**(48)**	(2)
	$ (1)	$ 24

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

6. INCOME TAXES

($ millions)	Three Months Ended June 30 **2002**	2001	Six Months Ended June 30 **2002**	2001
Provision for Income Taxes:				
Current				
Canada	**$ 36**	$ 136	**$ 73**	$ 324
United States	**8**	–	**8**	3
Ecuador	**7**	–	**7**	–
United Kingdom	**5**	2	**8**	5
Other	**–**	–	**–**	1
	56	138	**96**	333
Future	**99**	(26)	**141**	50
	$ 155	$ 112	**$ 237**	$ 383

7. LONG-TERM DEBT

($ millions)	As at **June 30, 2002**	December 31, 2001
Canadian dollar denominated debt		
Revolving credit and term loan borrowings	**$ 1,560**	$ 37
Unsecured debentures, including capital securities	**1,830**	725
	3,390	762
U.S. dollar denominated debt		
U.S. unsecured senior notes	**3,801**	1,608
U.S. revolving credit and term loan borrowings	**314**	–
	4,115	1,608
	7,505	2,370
Increase in value of debt acquired	**128**	–
Current portion of long-term debt	**(108)**	(160)
	$ 7,525	$ 2,210

Certain of the Notes and Debentures of the Company were acquired in the business combination described in Note 3 and are accounted for at their fair value. The difference between the fair value and the principal amount of these debts of approximately $128 million is being amortized over the remaining life of the outstanding debt acquired, approximately 15 years.

As required by Canadian generally accepted accounting principles, the Company's U.S. dollar denominated debt is translated into Canadian dollars at the period end exchange rate. Translation gains and losses are recorded in income. For the six months ended June 30, 2002, the Company recorded a foreign exchange gain of $180 million ($142 million after tax) related primarily to the translation of U.S. dollar debt.

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

8. SHARE CAPITAL

		June 30, 2002			December 31, 2001		
(millions)		**Number**		**Amount**	Number		Amount
Common shares outstanding, beginning of period		**254.9**	**$**	**196**	254.8	$	148
Shares repurchased		**–**		**–**	(0.2)		–
Shares issued under option plans		**2.9**		**69**	1.9		48
Shares issued to AEC Shareholders	*(note 3)*	**218.5**		**8,397**	–		–
Adjustments due to Canadian Pacific Limited reorganization		**–**		**–**	(1.6)		–
Common shares outstanding, end of period		**476.3**	**$**	**8,662**	254.9	$	196

The Company has a stock-based compensation plan (EnCana plan) that allows employees 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 plan are generally fully exercisable after three years and expire five years after the grant date. Options granted under previous EnCana and Canadian Pacific Limited replacement plans expire 10 years from the date the options were granted.

In conjunction with the business combination transaction described in Note 3, options to purchase AEC common shares were replaced with options to purchase common shares of EnCana (AEC replacement plan). The transaction also resulted in these replacement options, along with all options outstanding under the EnCana plan, becoming exercisable after the close of business on April 5, 2002.

The following tables summarize the information about options to purchase common shares at June 30, 2002:

	Share Options *(millions)*	**Weighted Average Exercise Price** *($)*
Outstanding, beginning of period	**10.5**	**32.31**
Granted under EnCana plan	**10.9**	**48.33**
Granted under AEC replacement plan	**13.1**	**32.01**
Granted under Directors' plan	**0.1**	**48.04**
Exercised	**(2.9)**	**24.26**
Forfeited	**(0.2)**	**31.84**
Outstanding, end of period	**31.5**	**38.53**
Exercisable, end of period	**20.5**	**33.32**

	Outstanding Options			Exercisable Options	
Range of Exercise Price *($)*	Number of Options Outstanding	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*	Number of Options Outstanding	Weighted Average Exercise Price *($)*
13.50 to 19.99	4.5	1.3	18.55	4.5	18.55
20.00 to 24.99	2.6	2.7	22.22	2.6	22.22
25.00 to 29.99	3.6	2.9	26.58	3.6	26.58
30.00 to 43.99	2.1	3.5	38.02	2.1	38.02
44.00 to 53.00	18.7	4.0	47.94	7.7	47.40
	31.5	3.1	38.53	20.5	33.32

Notes to Consolidated Financial Statements *(Unaudited)*

8. SHARE CAPITAL (continued)

The Company does not record compensation expense in the financial statements for share options granted to employees and directors because there is no intrinsic value at the date of grant. If the fair-value method had been used, the Company's net earnings and net earnings per share would approximate the following pro forma amounts:

($ millions, except per share amounts)	Six Months Ended June 30 2002	2001
Compensation Costs	**$ 50**	$ 10
Net Earnings		
As reported	**591**	922
Pro forma	**541**	912
Net Earnings per Common Share		
Basic		
As reported	**1.65**	3.60
Pro forma	**1.51**	3.56
Diluted		
As reported	**1.62**	3.52
Pro forma	**1.48**	3.49

As described above, the acquisition of AEC resulted in all outstanding options at April 5, 2002 becoming fully exercisable. As the stock option expense is normally recognized over the expected life, the early vesting of outstanding options resulted in an acceleration of the compensation cost. As such, a $33 million expense relating to options outstanding at April 5, 2002 was included in the 2002 pro forma earnings above.

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:

	Six Months Ended June 30 2002	2001
Risk-free interest rate	**4.46%**	4.24%
Expected lives *(years)*	**3.00**	3.00
Expected volatility	**0.35**	0.35
Annual dividend per share	**$ 0.40**	$ 0.40

9. PER SHARE AMOUNTS

The following table summarizes the Common Shares used in calculating net earnings and cash flow per Common Share.

	Three Months Ended June 30		Six Months Ended June 30	
(millions)	**2002**	2001	**2002**	2001
Weighted average Common Shares outstanding – basic	**461.1**	255.9	**358.2**	255.6
Effect of dilutive securities	**8.9**	5.5	**6.8**	5.4
Weighted average Common Shares outstanding – diluted	**470.0**	261.4	**365.0**	261.0

Net earnings per common share calculations include the impact of the Distributions on Preferred Securities, net of tax for the three months of $1 million (three months 2001 – $1 million) and for the year to date of $1 million (year-to-date 2001 – $2 million).

EnCana Corporation

Notes to Consolidated Financial Statements *(Unaudited)*

10. FINANCIAL INSTRUMENTS

Unrecognized gains (losses) on risk management activities:

($ millions)	June 30, 2002
Natural gas	$ 194
Crude oil	(13)
Gas storage	(2)
Foreign currency	(102)
Interest rates	60
Preferred securities	6
	$ 143

Information with respect to natural gas, crude oil, currency and interest rate hedge contracts at December 31, 2001 is disclosed in Note 17 to the PanCanadian annual audited consolidated financial statements and Note 15 to the AEC annual audited consolidated financial statements.

11. RECLASSIFICATION

Certain information provided for prior periods has been reclassified to conform to the presentation adopted in 2002.

EnCana Corporation

Supplemental Financial Information *(Unaudited)*

For the Three Months Ended June 30, 2002

FINANCIAL STATISTICS

(C$ millions, except per share amounts)	2002 Q2
Net Earnings from Continuing Operations	494
Per share – Basic	1.07
– Diluted	1.05
Net Earnings	458
Per share – Basic	0.99
– Diluted	0.97
Cash Flow from Continuing Operations	916
Per share – Basic	1.99
– Diluted	1.95
Cash Flow from Operations	938
Per share – Basic	2.03
– Diluted	2.00

Shares	
Common Shares outstanding *(millions)*	
Average	461.1
Average diluted	470.0
Price range *($ per share)*	
TSX – C$	
High	50.25
Low	43.62
Close	46.70
NYSE – US$	
High	32.20
Low	28.50
Close	30.60
Share volume traded *(millions)*	113.2
Share value traded *($ millions weekly average)*	412.6

Ratios	
Debt to Capitalization	39%

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the Three Months Ended June 30, 2002

OPERATING STATISTICS

SALES VOLUMES	2002 Q2
Produced Gas *(MMcf/d)*	
Canada	**2,144**
United States	**428**
United Kingdom	**8**
	2,580
Oil and Natural Gas Liquids *(bbls/d)*	
Onshore North America	
Conventional Light and Medium Oil	**66,807**
Conventional Heavy Oil	**76,233**
Natural Gas Liquids	
Canada	**16,796**
United States	**7,115**
Total Onshore North America Conventional	**166,951**
Syncrude	**24,295**
Total Onshore North America	**191,246**
Offshore and International	
Ecuador	**59,864**
United Kingdom	**11,966**
Total Offshore and International	**71,830**
	263,076
Total *(boe/d)*	**693,104**

PER-UNIT RESULTS

Produced Gas – Canada *($/Mcf)**	
Price, net of transportation and selling	**4.11**
Royalties	**0.65**
Operating expenses	**0.54**
Netback including hedge	**2.92**
Hedge	**(0.12)**
Netback excluding hedge	**3.04**
Produced Gas – United States *(C$/Mcf)**	
Price, net of transportation and selling	**3.62**
Royalties	**0.98**
Operating expenses	**0.38**
Netback including hedge	**2.26**
Hedge	**0.06**
Netback excluding hedge	**2.20**

* Excludes the effect of $77 million increase to consolidated revenues relating to the mark-to-market value of the AEC fixed price forward natural gas contracts recorded as part of the purchase price allocation.

Supplemental Oil and Gas Operating Statistics *(Unaudited)*

For the Three Months Ended June 30, 2002

OPERATING STATISTICS

PER-UNIT RESULTS (continued)	2002 Q2
Conventional Light and Medium Oil *($/bbl)*	
Price, net of transportation and selling	33.76
Royalties	4.36
Operating expenses	7.25
Netback including hedge	22.15
Hedge(1)	(1.59)
Netback excluding hedge	23.74
Conventional Heavy Oil *($/bbl)*	
Price, net of transportation and selling	26.09
Royalties	3.09
Operating expenses	5.87
Netback including hedge	17.13
Hedge(1)	(0.76)
Netback excluding hedge	17.89
Total Conventional Oil *($/bbl)*	
Price, net of transportation and selling	29.67
Royalties	3.68
Operating expenses	6.51
Netback including hedge	19.48
Hedge(1)	(1.15)
Netback excluding hedge	20.63
Natural Gas Liquids *($/bbl)*	
Price, net of transportation and selling	29.92
Royalties	4.69
Netback	25.23
Syncrude *($/bbl)*	
Price, net of transportation and selling	40.09
Gross overriding royalty and other revenue	0.16
Royalties	0.42
Cash operating expenses	30.47
Netback including hedge	9.36
Hedge(1)	(0.42)
Netback excluding hedge	9.78
Ecuador Oil *($/bbl)*	
Price, net of transportation and selling	31.63
Royalties	10.76
Operating expenses	5.70
Netback including hedge	15.17
Hedge(1)	(0.04)
Netback excluding hedge	15.21
United Kingdom Oil *($/bbl)*	
Price, net of transportation and selling	37.78
Operating expenses	3.12
Netback including hedge	34.66
Hedge	–
Netback excluding hedge	34.66

(1) Relates to share of contract volume of 85,000 bbls/d for January to March 2002.

EnCana Corporation
EnCana on 8th
1800 855 2nd Street SW
PO Box 2850
Calgary AB Canada T2P 2S5

tel: (403) 645-2000
fax: (403) 645-3400

www.encana.com