2002 ANNUAL REPORT

EnCana[2]

BUILDING A BEST-IN-CLASS ENTERPRISE

ENTERING	ENHANCING	ENSURING	ENTREPRENEURIAL
A new era	*A competitive advantage*	*Momentum*	*Organization*

HIGHLIGHTS – 2002 (PRO FORMA)

Completed merger of equals to create one of the world's leading independent oil and gas companies

Increased gas sales by 16% to 2.76 billion cubic feet per day

Increased conventional oil and natural gas liquids (NGLs) sales by 5% to 231,300 barrels per day

Increased year-end conventional proved reserves by 10% to 2.5 billion barrels of oil equivalent

Exploration success at Tahiti in the Gulf of Mexico and successful appraisal drilling at Buzzard in the U.K. central North Sea

Divested $700 million in non-core properties and assets

Achieved a total shareholder return of 19%

CORPORATE PROFILE EnCana is one of the world's leading independent oil and gas companies, driven to be the industry's best-in-class benchmark in per-share growth, production cost and value creation. The merger of two leading North American oil and gas explorers and producers, Alberta Energy Company Ltd. (AEC) and PanCanadian Energy Corporation (PanCanadian), has created a flagship, Canadian-headquartered, world-class independent oil and gas company. EnCana embodies two proud and strong histories that together provide a dynamic foundation for building an even stronger future. From its origins on the western Canadian plains, EnCana has expanded to major hydrocarbon producing basins in the Americas and the North Sea, and is applying creativity and skill in exploring for new resources in select international locations. EnCana combines high-quality, high-growth assets with superior core competencies, financial strength and proven leadership to deliver industry-leading performance for investors.

The Power of 2

"IT IS CLEAR THAT THE COMBINATION OF ASSETS AND CAPABLE PEOPLE WILL GENERATE MORE TOGETHER FOR ENCANA SHAREHOLDERS THAN EITHER COMPANY COULD HAVE REALIZED ON ITS OWN."

Gwyn Morgan
President & Chief Executive Officer

FINANCIAL	*Pro forma*
For the year ended December 31, 2002 (C$ millions, except per share amounts)	
Cash Flow	$ 4,211
per share – diluted	$ 8.71
Net Earnings	$ 1,254
per share – diluted	$ 2.59
Capital Investment	
Core Programs	$ 4,525
Acquisitions	$ 1,227
Dispositions	$ 695
Net Capital Investment	$ 5,057
Debt-to-EBITDA *(times)*	1.6
Debt-to-Capitalization *(%)*	36

OPERATING	*2002 Pro forma*	*2001 Pro forma*	*% Change*
Natural Gas Sales *(MMcf/d)*			
Canada	2,248	2,088	8
U.S.	500	279	79
International	10	9	11
	2,758	2,376	16
Oil and NGLs Sales *(bbls/d)*			
Canada – Conventional	161,761	151,343	7
– Syncrude	31,556	30,687	3
U.S.	7,961	4,734	68
International	61,609	63,261	-3
	262,887	250,025	5
Total Gas, Oil and NGLs Sales *(BOE/d)*	722,554	646,025	12
Conventional Reserve Additions *(MMBOE @ 6:1)*	473		
Reserve Replacement Costs (Proved)			
C$/BOE, before royalties	9.60		
US$/BOE, after royalties	8.20		

To Fellow Shareholders

WELCOME TO ENCANA'S INAUGURAL ANNUAL REPORT

The moments in history are rare when two successful and proven companies capture an opportunity to exponentially expand their strength, capacity and potential in one transforming transaction. In 2002, PanCanadian Energy Corporation and Alberta Energy Company Ltd. did just that, merging to capitalize on *The Power of 2* by creating EnCana Corporation. The motive was simple: create a Canadian-headquartered, flagship independent oil and natural gas company able to compete wherever it chooses to go – a best-in-class enterprise. As the saying goes, "Make no small plans." Our objective is to be the industry's best-in-class benchmark in production cost, per-share growth and value creation for shareholders.

GWYN MORGAN PRESIDENT & CHIEF EXECUTIVE OFFICER

AN EXTRAORDINARY FOUNDATION EnCana's roots stretch back to the early years of Canadian history and our two founding companies each had more than a quarter century of creating value and building shareholder confidence. Today, together, our future is brighter than ever. Here's why.

Anything worthwhile and lasting is built steadily and strongly, one step at a time. Each stone is carefully chosen and competently laid, providing the strength needed for the next. So, year-by-year, well-by-well, deal-by-deal, a great company has emerged, a company that reflects the track records of those who have built it over so many years. In a world where some organizations seem to come out of nowhere and blossom at unimaginable speed, only to wither and crumble, I take pride in leading an enterprise that I have helped build for more than 25 years and my executive team has helped to build for a combined 125 years. The reputation and performance of these people and those who work with them are clear for all to see. This is also true of our elected shareholder representatives. EnCana's Board consists of

"OUR OBJECTIVE IS TO BE THE INDUSTRY'S BEST-IN-CLASS BENCHMARK IN PRODUCTION COST, PER-SHARE GROWTH AND VALUE CREATION FOR SHAREHOLDERS."

16 Directors – eight from each of the legacy firms – who are accomplished builders, people respected and proven in the business world. During his tenure at Canadian Pacific Limited, your Chairman of the Board, David O'Brien, built five strong profitable companies, including PanCanadian, which were eventually spun off, creating significant shareholder value. In a world where the need for trust, values and a strong moral compass is more evident than ever, these are the traditions and the track records of accomplishment upon which we are building EnCana.

FOUR PILLARS OF VALUE CREATION Upon that extraordinary foundation, EnCana has erected its own four pillars of value creation: high-quality assets, solid credible reserves, strong financial management and sound corporate governance. In the pages of this report we define those pillars. You'll see that our high-quality assets are exceptional: nearly 17 million net undeveloped acres in North America's prime onshore sedimentary basins. Our Company holds nearly 2.5 billion barrels of conventional proved oil equivalent reserves in North America and internationally. The prime growth potential from our huge North American land base is characterized by what we call resource plays. Our engineers estimate that these plays contain an additional 10 trillion cubic feet of gas and 800 million barrels of oil – a potentially recoverable resource capable of profitable, repetitive, low-risk production growth for years to come. Those advantages, coupled with the lower decline rate performance of our resource plays and the expertise of our people, give us the confidence to set industry-leading growth targets.

Reserves define core value in oil and gas companies. The credibility of EnCana's reserve estimates resides in our policy, a rarity among our peers, that 100 percent of reserves be evaluated and re-verified each year by independent reservoir engineering firms, a process that is overseen by an independent committee of our Board of Directors. Best-in-class reserve evaluation practices, combined with full and transparent financial disclosure, mean that our financial and reserve reporting meets or exceeds the highest standards in business today. In his letter, Chairman David O'Brien outlines the fourth pillar: sound corporate governance.

ENTREPRENEURIAL ACCOUNTABILITY EnCana's organizational strategy combines the competitiveness, entrepreneurship and agility of a family of mid-sized business units with the breadth of knowledge, information technology, financial strength and resiliency of a large company.

EnCana's business units are focused on specific exploration and production regions where they are accountable for achieving best-in-class results by applying superior core competencies and breakthrough thinking. EnCana's corporate groups are accountable for accurate reporting and reliable control systems, along with ensuring the most effective and competitive information technology, human resources and stakeholder relations practices. Every employee has a High Performance Contract that aligns rewards and recognition with the achievement of clear, measurable goals.

STRATEGIC ALIGNMENT EnCana is one of the world's largest independent oil and gas companies, based on daily production and enterprise value. Size brings inherent advantages: greater share trading liquidity which broadens our appeal to major institutional investors, economies of scale when we drill 3,000 wells a year or order thousands of lengths of drill pipe, and economic synergies that reduce capital, operational and administrative costs. Yet being biggest only matters if you can translate that capacity into competitive advantages that yield leading performance. That is our focus. Our large North American resource plays enable us to sustain industry-leading internal growth. We are also developing major offshore discoveries and pursuing exploration prospects in North America and internationally. Our diverse asset base means we are not dependent on any one project or play, and can be ruthlessly disciplined in moving out assets that don't meet our stringent criteria of superior returns, growth and critical mass, or which are simply worth more to others. Our strong balance sheet enables our business units to pursue their best internal projects and acquisition opportunities.

In 2002 and early 2003, we closed the opportunistic purchase of gas assets in the U.S. Rockies, sold our majority interests in two major oil pipelines and agreed to sell 10 percent of Syncrude. These events exemplify our disciplined focus on premium growth, high return assets, where we own a high working interest and operate the field and facilities. We select and develop oil and gas properties where we can apply our core technical and operational competencies, control the pace of development and manage operating costs. All the while, we maintain rigorous capital discipline. For example, we stress test investment in our oil and gas projects against the

"OUR DIVERSE ASSET BASE MEANS WE ARE NOT DEPENDENT ON ANY ONE PROJECT OR PLAY, AND CAN BE RUTHLESSLY DISCIPLINED..."

minimum price required to achieve a rate of return, after-tax, that exceeds our cost of capital. For 2003, we are targeting full-cycle, after-tax, risk-adjusted returns of at least 20 percent for Onshore North America development projects and 15 percent for exploration and longer lead time projects.

Our Midstream & Marketing division adds value to upstream production by getting the best available prices for our production and keeping an analytical eye on supply, demand and price fundamentals. EnCana owns North America's largest independent natural gas storage network, a key advantage to North America's largest independent natural gas producer. At the time of the merger, we made the decision to exit the merchant energy trading business.

2002 PERFORMANCE HIGHLIGHTS During a year focused on the momentous task of merging two large companies, EnCana's people delivered financial and operating performance that would have been remarkable even in a year without the challenge of merger integration. Daily sales grew 12 percent, the best internal growth in the industry, and we increased value by adding 470 million barrels of oil equivalent of proved reserves. Replacement costs were $9.60 per barrel of proved oil equivalent, very good performance, even after a downward reserve revision.

And the most important measure for shareholders – a 19 percent total return from share price appreciation and dividends, which outpaced the TSX index by 31 percent and an index of our U.S.-based peers by 21 percent.

Because of the current high oil and gas prices, one might assume the Company's market return was driven by higher year-over-year prices. In fact, average Canadian industry natural gas prices were down 35 percent to $4.07 per thousand cubic feet and the oil price was essentially even at US$26.15 per barrel. EnCana earned pro forma $1.25 billion, or $2.59 per common share diluted, and generated $4.21 billion, or $8.71 per common share diluted, of cash flow. Pro forma sales averaged 723,000 barrels of oil equivalent per day, comprised of 2.76 billion cubic feet of gas and 263,000 barrels of oil and natural gas liquids per day. These record results for a Canadian-headquartered exploration and production company place EnCana among the leading independents in the world. On the cost side, our pro forma operating and administrative costs averaged $4.77 per barrel of oil equivalent, which is among the best in our industry.

Our net capital investment reached $5.1 billion, resulting in the drilling of 2,443 net development wells with a 99 percent success rate and 576 net exploration wells with a 92 percent success rate, for a total of 3,019 net wells. Our asset base was further upgraded through $1.23 billion of opportunistic property and asset acquisitions in the U.S. Rockies and elsewhere, plus the sale of $695 million of non-core upstream and midstream assets. Early in 2003, we closed the sale of $1.6 billion of pipelines assets and 10 percent of our 13.75 percent Syncrude interest for an additional $1.07 billion, further strengthening the strongest balance sheet in our peer group.

Key operational accomplishments and results are presented in the body of this report; I will only highlight a few here.

In northeast British Columbia, EnCana completed a four-year land acquisition program that sews up the vast majority of one of the largest regional gas discoveries in Western Canada in the past decade. In the Greater Sierra region, where we hold more than two million net acres, we plan to drill in excess of 100 wells per year as we continue to exploit its huge gas resource potential.

In the U.S. Rockies, we've significantly increased production for the second year in a row – just three years after entering the region. Last year, our U.S. Rockies team drilled about 300 net wells, taking annual production to an average of 500 million cubic feet of gas per day. EnCana has quickly established a highly profitable growth base in a region that was largely overlooked by the U.S. industry.

In the deep water Gulf of Mexico, EnCana participated in the Tahiti oil discovery, which contains an estimated 100 to 125 million barrels net to EnCana. Our earlier Llano find is expected to begin production by 2004, followed by Tahiti later in the decade. In the U.K. central North Sea, our appraisal of Buzzard placed estimated recoverable reserves at 180 million barrels net to EnCana. First production is expected in 2006.

Canada's first two commercial SAGD (steam-assisted gravity drainage) projects demonstrated their promise towards achieving industry-leading performance in the thermal recovery of Alberta's oilsands.

"WE SELECT AND DEVELOP OIL AND GAS PROPERTIES WHERE WE CAN APPLY OUR CORE TECHNICAL AND OPERATIONAL COMPETENCIES, CONTROL THE PACE OF DEVELOPMENT AND MANAGE OPERATING COSTS."

And North America's largest independent gas storage network is getting larger with a doubling of capacity at Wild Goose in northern California underway and a new Countess gas storage facility in southern Alberta set to open its first phase of operations later this spring.

CHALLENGES IN 2002 As you can imagine, integrating two large companies was a complex and demanding task. Our objective was to quickly define EnCana's organizational structure, its leaders, place people in their new teams, establish definitive goals and clearly communicate the values upon which we'd build our future together. While much could be said about this process, what's important for investors to know is that EnCana is fully integrated, with our focus entirely on delivering great results by realizing our potential.

Naturally there were operational setbacks. The Ecuador Value Added Tax dispute remains unresolved but we expect that this issue will move to international arbitration in 2003. Our inaugural 100 percent independent reserve evaluation resulted in a larger downward revision than we anticipated. Conversely, 2002 reserve additions were outstanding, more than offsetting production and the downward revision, resulting in a net, year-over-year increase in conventional proved reserves of 10 percent. Early in 2003, we announced deferral of our Deep Panuke gas development offshore Canada's East Coast. This project still has great potential, but we need to find ways to ensure that its risk-adjusted return meets EnCana's disciplined criteria so that it can compete for capital with an array of robust gas projects. And, Canadian business faced major uncertainty and a potential negative impact with Canada's decision to ratify the Kyoto Protocol. As a Canadian business leader, I felt it important to actively engage in this crucial public policy debate by championing a "Made in Canada" approach to emissions reductions. To date, there has been significant progress in defining both the expectations and the maximum impact on energy intensive Canadian industries in a manner that more closely reflects the Canadian reality. For more details, I ask you to refer to the Corporate Responsibility section of this report. I will only summarize by saying your Company is an environmental leader, and very well positioned to achieve the reduction targets that are expected to be part of Canada's greenhouse gas program.

OUTLOOK FOR 2003 Since early this year, natural gas prices have rapidly gained strength due mainly to cold winter weather and the decline of Canadian and U.S. gas production. EnCana's strong production growth contrasts with industry declines. Given our industry-leading gas reserves, production and storage growth, it's hard not to be excited about the year ahead, and many beyond that.

Recent oil prices are higher due mainly to the Iraqi crisis and a general strike in Venezuela. Again, EnCana is poised to grow oil production strongly in the coming years, initially from our Canadian heavy oil properties and the Oriente Basin of Ecuador, then beginning in 2006, from development of world-class discoveries in the U.K. central North Sea, followed later by the deep water Gulf of Mexico. World oil prices are subject to many more influences than North American natural gas. It does appear, however, that the surplus oil capacity of the OPEC countries has narrowed and may well continue to do so when world economic recovery begins.

The merger year is behind us. In 2003, EnCana is focusing on three mantras: "Keep it simple. Focus and deliver. Execute with excellence." We know that you have high expectations of EnCana, but no higher than those we have of ourselves.

We are unique in the industry by targeting an average annual growth in per-share sales of 10 percent for several years ahead. We've set these targets because our growth is identifiable and visible from our existing asset base and because we believe we can be the lowest per-unit cost producer where we operate.

"WE ARE UNIQUE IN THE INDUSTRY BY TARGETING AN AVERAGE ANNUAL GROWTH IN PER-SHARE SALES OF 10 PERCENT FOR SEVERAL YEARS AHEAD."

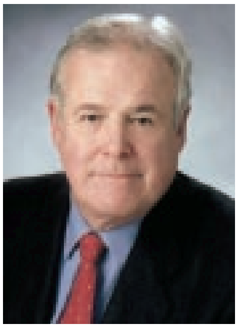
OUR HIGH PERFORMANCE ENCANANS It is normal for the Chief Executive's letter to shareholders to recognize and thank staff of the Company. But there is nothing normal about the 2002 efforts and accomplishments of the people we call EnCanans. In the face of seemingly endless change, unfamiliar technology systems, personal uncertainty, new team members, reorganization and more, EnCanans embraced the vision, kept their eye on the ball and delivered outstanding results while demonstrating a positive, professional, can-do attitude that was truly awesome to witness.

My executive team and I are immensely proud to say that EnCanans cleared all the merger hurdles and met or exceeded all of the industry-leading performance targets set at the time of the merger. This is truly a team of people who have proven themselves worthy of the term "best-in-class."

GWYN MORGAN

President & Chief Executive Officer

February 28, 2003



CHAIRMAN'S MESSAGE

In reading EnCana's first Annual Report, I believe that you will be impressed by the strength of this enterprise – our land, our people, our technology. We are an asset-rich company with a vast array of opportunities. As Chairman of the Board, I have a responsibility to lead the Board of Directors in ensuring that EnCana creates maximum value from these assets. But I believe that I have an equally important role – ensuring that shareholders and investors have confidence in this Company, confidence that the numbers we report accurately reflect EnCana's financial performance, confidence that we have correctly evaluated our reserves – which represent EnCana's future value – and confidence that the overall governance systems are truly protecting the interests of the shareholders.

As non-executive Chairman of the Board, I have been very much focused, during this inaugural year for EnCana, on ensuring that the foundation is in place to provide that confidence. Of critical importance is the fact that the majority of the Directors – 15 of 16 – are independent of management and that the Board regularly meets without the presence of management. Equally important is the depth, diversity and professional experience of the Board members. EnCana's Board is rich with extremely knowledgeable and skilled individuals who bring a range of talents, expertise and critical perspective to every discussion. In determining the membership of our six Board committees, we focused on making the best use of our Directors' skills and experience. For example, the Reserves Committee membership includes Directors with extensive oil and gas professional training and years of practical industry experience; the Audit Committee members possess strong financial and business credentials and knowledge. When writing EnCana's corporate governance guidelines, we sought to establish leading corporate

DAVID P. O'BRIEN CHAIRMAN OF THE BOARD

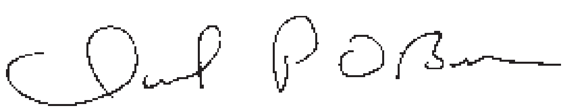
practices that contain periodic and rigorous performance reviews. We are committed to continuous improvement in corporate governance and will implement changes as required to ensure we are in line with current best practices.

Throughout EnCana's founding year, all Board members have devoted a tremendous amount of time getting to know the Company's strengths, weaknesses, competitive advantages and business opportunities. At this time, I would like to acknowledge their support and guidance, notably former Alberta Energy Company Ltd. Chairman Stan Milner, who delivered wise and insightful leadership at AEC through a period of strong growth since 1999 and through the merger last year. Three other individuals who also resigned their positions with the formation of the EnCana Board – William Stinson, Dian Cohen and Donald Macdonald – made significant contributions to building EnCana's predecessor companies and provided valuable guidance throughout the merger process. I would also like to especially thank two members who will not be standing for re-election to the EnCana Board – John Lamacraft and Don Stacy. They were both long-standing members of the AEC Board and brought years of valuable experience to the table during this formative year.

As EnCana moves into its second year, I believe that shareholders can have confidence that the Board is committed to working with management to maintain the highest standards of integrity and governance and to produce superior returns for our shareholders.

I, along with my fellow Directors, would like to recognize the enormous accomplishments of management and all EnCana employees in 2002. All shareholders can be confident that EnCana has the talents, skills and other resources required to prosper in the coming years.

ON BEHALF OF THE BOARD



DAVID P. O'BRIEN

Chairman of the Board

February 28, 2003

AN EXTRAORDINARY FOUNDATION

ENCANA™

1970 *to* 2002

1970 *to* 1974 | 1975 *to* 1979 | 1980 *to* 1984 | 1985 *to* 1989 | 1990 *to* 1994 | 1995 *to* 1999 | 2000 | 2001 | 2002 APRIL 8TH ENCANA IS BORN

1971
PanCanadian Petroleum Limited is created by the amalgamation of Canadian Pacific Oil and Gas Company and Central-Del Rio Oils. It is the largest independent producer of crude oil and natural gas in Canada.

1972
PanCanadian embarks on ambitious development of shallow gas on its royalty-free lands in the Irrigation Block located in southern Alberta.

1975
Alberta Energy Company Ltd. begins operations as a diversified resource company, owned 50% by the public and 50% by the Government of Alberta. Inaugural assets include oil and gas exploration rights to the 600,000-acre Suffield Block in southeast Alberta.

1982
PanCanadian's head office moves into the Company's new corporate headquarters in PanCanadian Plaza.

1988
AEC opens AECO-C natural gas storage, creating a benchmark for Canadian gas prices and a North American trading hub.

1992
PanCanadian launches an aggressive, multi-year capital program, taking production to over 260,000 BOE/d over the next four years.

1993
The Alberta Government sells its remaining stake, making AEC a 100% publicly owned company.

1994
Gwyn Morgan appointed President and CEO of AEC.

1996
PanCanadian enters the East Coast Canada region through the purchase of the Cohasset and Panuke oil fields offshore Nova Scotia.

AEC buys Conwest Exploration Company and focuses on oil and gas exploration and production. Establishes high-performance growth strategy.

1997
PanCanadian expands heavy oil extraction expertise through acquisition of CS Resources, including the Christina Lake property.

1998
AEC acquires Amber Energy and its interest in the Pelican Lake field.

1999
AEC acquires Pacalta Resources and its operating interests in oil production in Ecuador. Construction of first phase of commercial SAGD begins.

PanCanadian makes a significant offshore natural gas discovery under the Panuke oil field, offshore Nova Scotia.

2000
PanCanadian launches one of the continent's largest CO_2 miscible flood projects at Weyburn, Saskatchewan.

AEC ranks as Canada's largest natural gas producer and expands into the U.S. Rockies acquiring an operating interest in Wyoming's Jonah field. Natural gas production exceeds 1 Bcf/d.

2001
PanCanadian Petroleum Limited becomes PanCanadian Energy Corporation – 100% publicly traded under the symbol PCE on the Toronto Stock Exchange and PCX on the New York Stock Exchange. It drills a major light oil discovery at Buzzard in the U.K. Produced gas sales exceed 1 Bcf/d. Liquids sales exceed 114,000 bbls/d.

AEC ranks as Canada's largest natural gas producer and the largest independent operator of gas storage in North America. Produced gas sales exceed 1.3 Bcf/d. Liquids sales exceed 135,000 bbls/d.

EACH AEC SHARE CONVERTED TO 1.472 PANCANADIAN SHARES

PANCANADIAN CHANGES ITS NAME TO ENCANA

JANUARY 25
AEC and PanCanadian each issue news releases advising that they are in discussions with respect to a potential merger of equals.

JANUARY 27
AEC and PanCanadian execute a combination agreement and hold a joint news conference announcing the merger agreement.

APRIL 4
AEC shareholders and optionholders and PanCanadian shareholders approve the planned merger of AEC and PanCanadian to form EnCana Corporation. The Court of Queen's Bench of Alberta approves the arrangement on April 5, 2002.

APRIL 8
EnCana shares begin trading on the Toronto Stock Exchange and New York Stock Exchange under the symbol ECA.

HISTORICAL SHARE PRICE PERFORMANCE

AEC
PANCANADIAN

PANCANADIAN ENERGY CORPORATION
1971

PanCanadian's roots go back to Canada's early days and the construction of the nation's first transcontinental railway. In 1881, the Government of Canada commissioned Canadian Pacific Railway (CPR) to build a railroad connecting the country from east to west. As partial payment, CPR received 25 million acres of land, some of which came with mineral and surface rights. In 1883, a CPR crew drilling for water near Medicine Hat made Alberta's first natural gas discovery, which marked the beginning of Western Canada's petroleum industry. CPR created Canadian Pacific Oil and Gas Company (CPOG) in 1958 to hold its mineral rights and begin an aggressive exploration and production program. PanCanadian Petroleum Limited was created in 1971 with the amalgamation of CPOG and Central-Del Rio Oils.

ALBERTA ENERGY COMPANY LTD.
1975

The Government of Alberta created Alberta Energy Company Ltd. (AEC) to provide Albertans and other Canadians with an opportunity to participate, through share ownership, in the industrial and energy-related growth of Alberta. In 1975, the Alberta Government sold a one-half interest in AEC, raising $75 million in a highly successful public share offering. AEC's founding mandate was to participate in resource-development projects. Over the years, AEC invested in various industries in addition to oil and natural gas, including forest products, petrochemicals, coal and steel. The Alberta Government gradually reduced its ownership until 1993 when it sold its remaining shares, making AEC a 100% publicly owned company. By 1995, AEC had focused its growth strategy solely on oil and gas after selling off all other resource investments.

ENCANA CORPORATION

ESTABLISHING THE BENCHMARK FOR A BEST-IN-CLASS ENTERPRISE

The merger of two of Canada's most successful independent oil and gas companies has created an enterprise with premium quality assets, a depth of technical expertise and the financial strength to succeed and grow in the highly competitive oil and gas industry. EnCana distinguishes itself with:

- Largest independent natural gas production in North America – daily produced gas sales averaged 2.76 billion cubic feet (pro forma) in 2002; targeting between 3.0 to 3.1 billion cubic feet per day in 2003
- Large oil and natural gas liquids (NGLs) production – daily conventional oil and NGLs production averaged 231,300 barrels (pro forma) in 2002; targeting conventional production of between 240,000 to 280,000 barrels per day in 2003
- One of the largest proved reserves bases among independent oil and gas companies – 9 trillion cubic feet of North American natural gas and 980 million barrels of conventional oil and NGLs reserves at year-end 2002. Reserves 100 percent externally evaluated
- Vast land position – 17 million net undeveloped acres Onshore North America; 77 million net undeveloped acres Offshore & International
- Largest independent natural gas storage network in North America – 145 billion cubic feet of natural gas storage capacity with 2.7 billion cubic feet per day withdrawal capability
- Strong balance sheet with 36 percent debt to capitalization and strong investment grade credit ratings

▲ *EnCana lands cover a vast expanse across North America*

To enhance its existing assets, EnCana continues to build its land base and prospect inventory, and employ its core competencies in exploiting these resources to the fullest. Elements of EnCana's competitive advantage include: ■ Large, exploitable resource plays in Western Canada and the U.S. Rockies. ■ Largest land holdings in the Western Canadian Sedimentary Basin with over 15 million net undeveloped acres including 3.5 million net undeveloped acres of fee simple land ■ Extensive exploration lands in offshore and international regions totalling more than 77 million net undeveloped acres ■ Leading technical competencies: multi-zone, tight gas exploitation; horizontal, underbalanced drilling; steam-assisted gravity drainage (SAGD); coalbed methane development; natural gas storage development ■ High netbacks achieved through low royalty and low operating cost structures ■ Operatorship, control of infrastructure and high working interests typically exceeding 85 percent in Onshore North America ■ Largest independent natural gas storage network in North America with a 2.7 billion cubic feet per day withdrawal rate ■ World-class discoveries offshore and international

EnCana's goal is to create shareholder value through predictable, profitable growth by efficiently developing the Company's high-quality asset base, exploring its unparalleled exploration land inventory and deploying its financial strength to achieve 10 percent average annual per-share sales growth for several years to come. Strategic priorities include: ■ *Making investment choices that balance per-share growth and return on capital over the long term* ■ *Growing natural gas production and storage capacity in North America* ■ *Exploiting tremendous oilsands resource potential – SAGD at Foster Creek and Christina Lake* ■ *Maintaining and enhancing low operating cost advantages* ■ *Building growth platforms in Ecuador, U.K. central North Sea, Gulf of Mexico and offshore East Coast Canada* ■ *Establishing new growth platforms through New Ventures exploration* ■ *Executing opportunistic acquisitions and divestitures*

▲ *EnCana natural gas plant in northwest Alberta*


ENCANA CORPORATION 2002
Ensuring2
ENSURING MOMENTUM: GOALS AND STRATEGIES

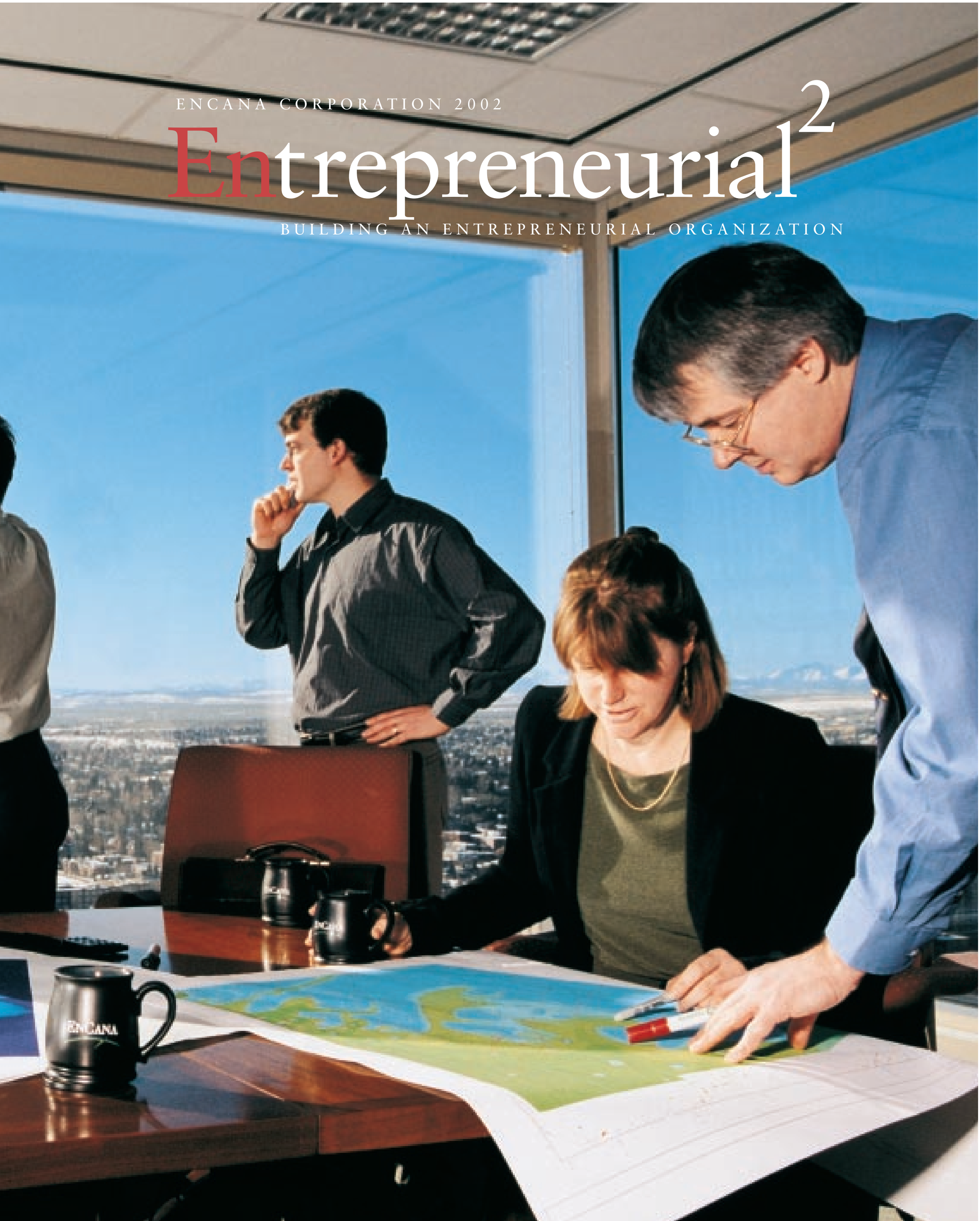
EnCana's organizational strategy is to combine the competitiveness, agility, entrepreneurial spirit and work environment of a family of business units with the breadth of knowledge and financial strength of a large company. ■ *The long-term vision is defined by the organization's leaders, while highly-efficient business units set clearly-established business plans, high-performance targets and annual objectives aimed at turning prospects into discoveries, projects into production, capital investment into strong returns, and vision into reality.* ■ *All EnCanans are accountable for their objectives and are rewarded when they achieve best-in-class performance.*

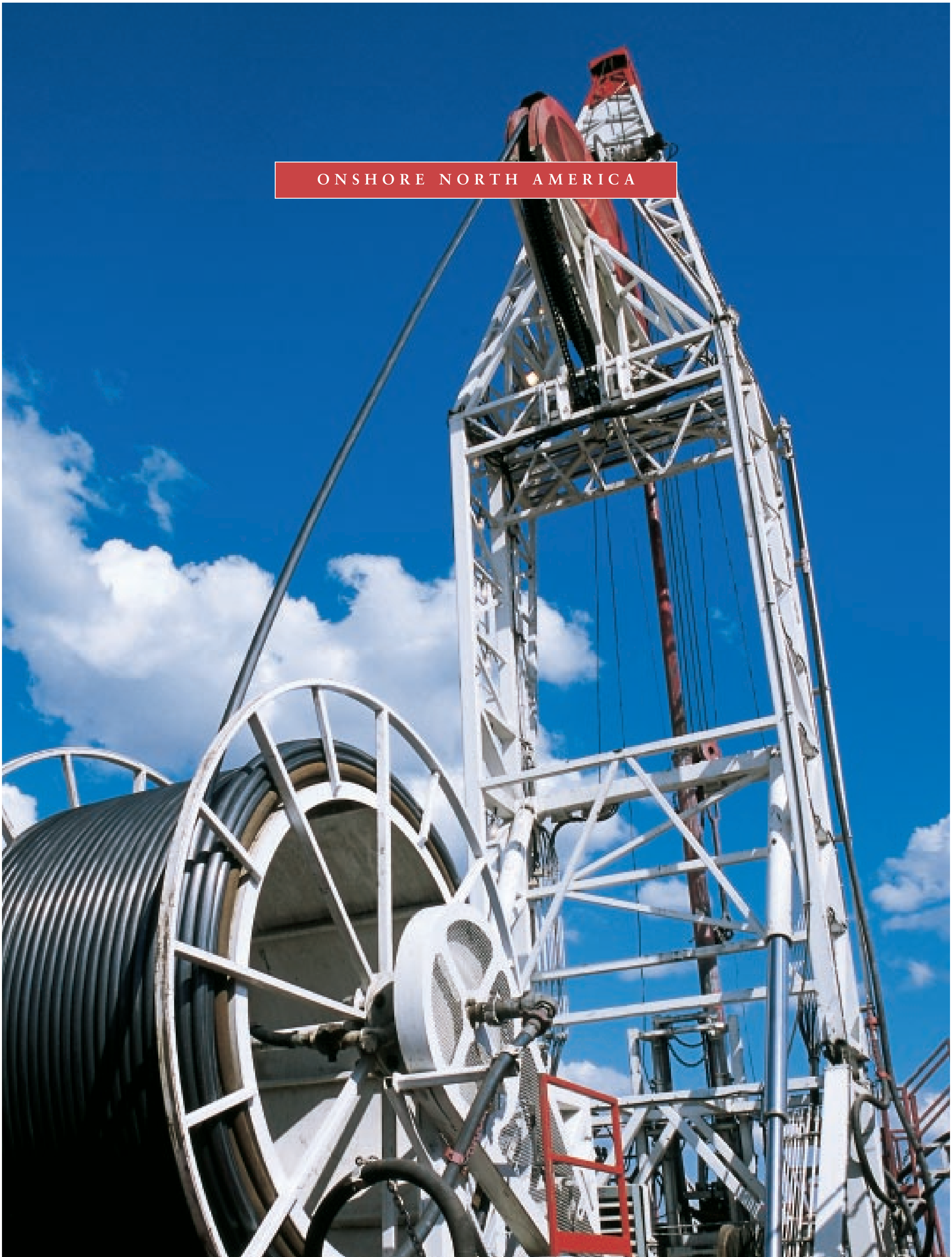
▲ *A Foothills region exploration team at work*

ENCANA CORPORATION 2002

Entrepreneurial²

BUILDING AN ENTREPRENEURIAL ORGANIZATION





▲ *Applying coil tubing technology in southeast Alberta*

Vision: THE MOST DYNAMIC AND SUCCESSFUL EXPLORATION AND PRODUCTION OPERATOR ON THE CONTINENT . . . THE ORGANIC GROWTH LEADER AMONG INDEPENDENT PRODUCERS

Goal: STEADY, RELIABLE AND HIGHLY PROFITABLE PER-SHARE GROWTH AVERAGING 10 PERCENT PER YEAR FOR SEVERAL YEARS

"We ensure that all of our capital programs exceed minimum return thresholds on a risk-adjusted basis and fit our strategic principles."

Randy Eresman
Chief Operating Officer
EnCana Corporation

ONSHORE NORTH AMERICA

Strategy and Competitive Advantages

EnCana's Onshore North America division is the core of the Company's assets and operations, containing about 90 percent of our daily production and reserves. Our Onshore North America land holdings are vast – more than 17 million net acres of undeveloped land.

At EnCana, we are focused on gas-weighted exploitation of our extensive lands and long-term exploitation of our abundant oilsands resource. We create long-term value by unlocking the plentiful and known reserves contained in what we call 'resource plays.' Resource plays are known to hold a massive volume of hydrocarbons across a very large areal expanse like our southern Alberta lands, or throughout a very thick vertical formation similar to our U.S. Rockies properties. EnCana's resource plays, which dominate our exploitation portfolio, demonstrate more predictable performance and generally have a lower and more constant longer-term decline rate than the industry average for conventional production.

Capturing value from resource plays requires pragmatic, experienced people deploying innovative technologies such as underbalanced horizontal drilling, huge underground rock fracturing and SAGD. Rock or sand formations incapable of flowing sufficient, economic volumes of gas or oil a decade ago are now producing at rates that consistently achieve dependable and profitable double-digit growth. Along side our technologies, we employ well-defined operating practices. We keep it simple. We focus and deliver. We hold high working interests and operatorship in order to select our best projects, control the pace of development and have complete cost control in our hands. As a result, EnCana's resource plays are typically very large-scale developments that have efficient assembly-line characteristics.

Our investment strategy is disciplined and focused on managing a portfolio of opportunities that provide the most attractive returns to shareholders – a minimum 20 percent rate of return on gas exploitation and at least 15 percent on exploration and oilsands. We drill the best prospects, farm out non-core properties and sell others, knowing that some assets offer more value to others. By developing our resource plays, EnCana can achieve steady, reliable, highly profitable organic growth, the kind that enables us to target a multi-year average annual growth rate of 10 percent per share.

ONSHORE NORTH AMERICA operations are concentrated in the Western Canadian Sedimentary Basin and the U.S. Rockies. In 2002, gas sales averaged 2.75 billion cubic feet per day and conventional oil and NGLs sales averaged 170 thousand barrels per day, a production level that would place EnCana's Onshore North America division, on its own, among the largest independent producers in North America. With conventional proved reserves of 9 trillion cubic feet of gas and 670 million barrels of oil and NGLs, a proved reserve life index in excess of nine years and an estimated resource potential of 10 trillion cubic feet of gas and 800 million barrels of oil on EnCana lands, Onshore North America is poised for further growth.

"An essential ingredient to successful portfolio management is an active inventory of both acquisition and divestiture candidates."

Randy Eresman
Chief Operating Officer
EnCana Corporation

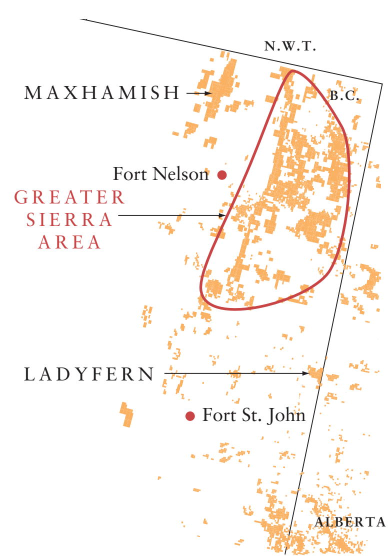
1 2002 HIGHLIGHTS *(pro forma)*

- 659,000 barrels of oil equivalent per day of oil, NGLs and gas sales: 2.75 billion cubic feet per day of natural gas sales, 169,700 barrels per day of conventional oil and NGLs sales, 31,600 barrels per day of synthetic crude oil sales.
- Proved reserve additions of 387 million barrels of oil equivalent including 1.5 trillion cubic feet of natural gas.
- Proved reserves replacement cost of $8.50 per barrel of oil equivalent.
- Completed major land purchases in the Greater Sierra area which increased EnCana's land position to more than 2 million net acres of undeveloped land in this area.
- Completed two opportunistic acquisitions, at Jonah in the Green River Basin, and in the Piceance Basin of the U.S. Rockies.
- Reached full production at world's first large-scale commercial SAGD project at Foster Creek; expansion of first phase underway.
- Started steam injection and production at Christina Lake, the Company's second SAGD project.
- Began demonstration-scale development of Canada's first commercial coalbed methane project.
- Reached agreement to sell Syncrude interest in early 2003.

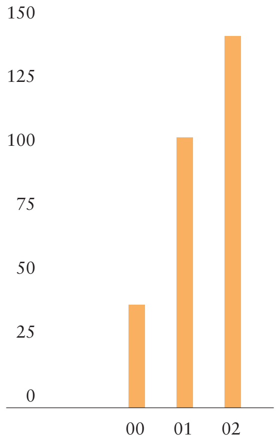
2 GOALS FOR 2003

- Achieve gas sales of between 3.0 and 3.1 billion cubic feet per day.
- Achieve conventional oil and NGLs sales of between 175,000 and 190,000 barrels per day.
- Target reserves replacement cost of $8.00 to $9.00 per barrel of oil equivalent on a proved basis.
- Target average conventional operating costs of between $3.70 and $3.90 per barrel of oil equivalent.

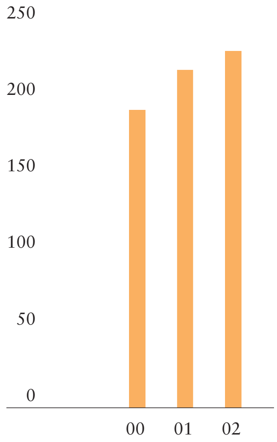
Greater Sierra



GREATER SIERRA
GAS PRODUCTION
MMcf/d (pro forma)



SOUTHERN PLAINS
TOTAL PRODUCTION
MBOE/d (pro forma)



3 FOOTHILLS

2002 Profile

- 659 million cubic feet per day of natural gas production.
- 12,600 barrels per day of oil and NGLs production.
- 6.7 million net acres of undeveloped land.
- Exploration upside on huge land base.

Strategy

- Focus on multi-year gas growth through high-impact resource plays.
- Acquire high working interests, dominant land positions and control infrastructure.
- Improve performance by using advanced technology, such as underbalanced and horizontal drilling to exploit resources.
- Conduct medium- to high-risk exploration.

Greater Sierra – an exploration-driven resource play

Large quantities of natural gas have long been known to exist in the Upper Devonian Jean Marie formation of northeast British Columbia's Greater Sierra area, but were considered uneconomic to produce. EnCana determined that through the use of underbalanced, horizontal drilling it could efficiently and profitably produce from these reservoirs. The Company then built a dominant land position which now covers more than 2 million net acres. Between 1998 and 2002, EnCana assembled a contiguous, linear strip of land running 280 kilometres north-south in a band 5 to 11 kilometres wide along the reef edge. The Jean Marie formation is a gas-charged carbonate reservoir containing sweet natural gas. EnCana's application of innovative drilling technology has made Greater Sierra the largest regional gas play discovered in Western Canada in the past decade. This is a model resource play, generating very attractive full-cycle returns. In 2002, production averaged 145 million cubic feet per day. The Company expects to drill in excess of 100 wells per year as it continues to exploit the huge gas resource potential of this area.

4 SOUTHERN PLAINS

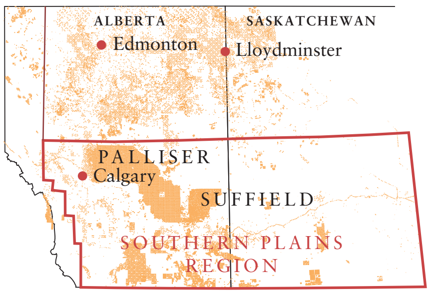
2002 Profile

- 1,055 million cubic feet per day of natural gas production.
- 55,200 barrels per day of oil and NGLs production.
- 6.6 million net acres of land, of which 3.1 million net acres are undeveloped.
- 3.6 million net acres of fee simple land.
- Extensive facilities and gathering pipelines infrastructure.

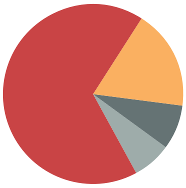
Strategy

- Continue efficient development of shallow and multi-zone conventional gas resources.
- Exploit extensive heavy oil resource.
- Demonstrate commercial viability of coalbed methane.

Southern Plains Region

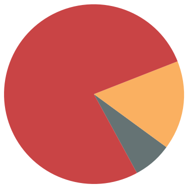


ONSHORE NORTH AMERICA
2003 FORECAST CONVENTIONAL
CAPITAL INVESTMENT
BY RISK PROFILE
($3.5 billion)



- 67% Low Risk Gas Exploitation
- 18% Low Risk Oil Exploitation
- 8% High Risk Exploration/Long Term Oilsands
- 7% Medium Risk Exploration

ONSHORE NORTH AMERICA
2003 FORECAST CONVENTIONAL
CAPITAL INVESTMENT
BY PRODUCT
($3.5 billion)



- 77% Natural Gas
- 16% Heavy Oil
- 7% Light/Medium Oil

5 CENTRAL PLAINS

Palliser and Suffield – Prolific legacy lands anchor resource potential

EnCana's Power of 2 is evident in the Company's foundation blocks – Palliser and Suffield – in Southern Plains. With daily production of more than one billion cubic feet of natural gas and more than 55,000 barrels per day of oil and NGLs, this region is a North America production leader in its own right. Southern Plains geology features sands with numerous producing zones that deliver steady growth through low-cost, in-fill drilling. By taking an assembly-line approach to producing gas, EnCana adds thousands of shallow wells per year, each taking just hours to drill. These wells are completed and tied-in, generally within a month, to a network of more than 5,000 kilometres of gathering pipes. With the majority of production from fee simple lands, and with low operating costs and favourable transportation agreements, netbacks are among the highest in Canada. EnCana's inherent competitive advantages of well-developed gas infrastructure, fee simple lands and the capacity to quickly and efficiently execute large scale developments in its own backyard mean that Southern Plains is one of the most profitable regions in the industry.

2002 Profile

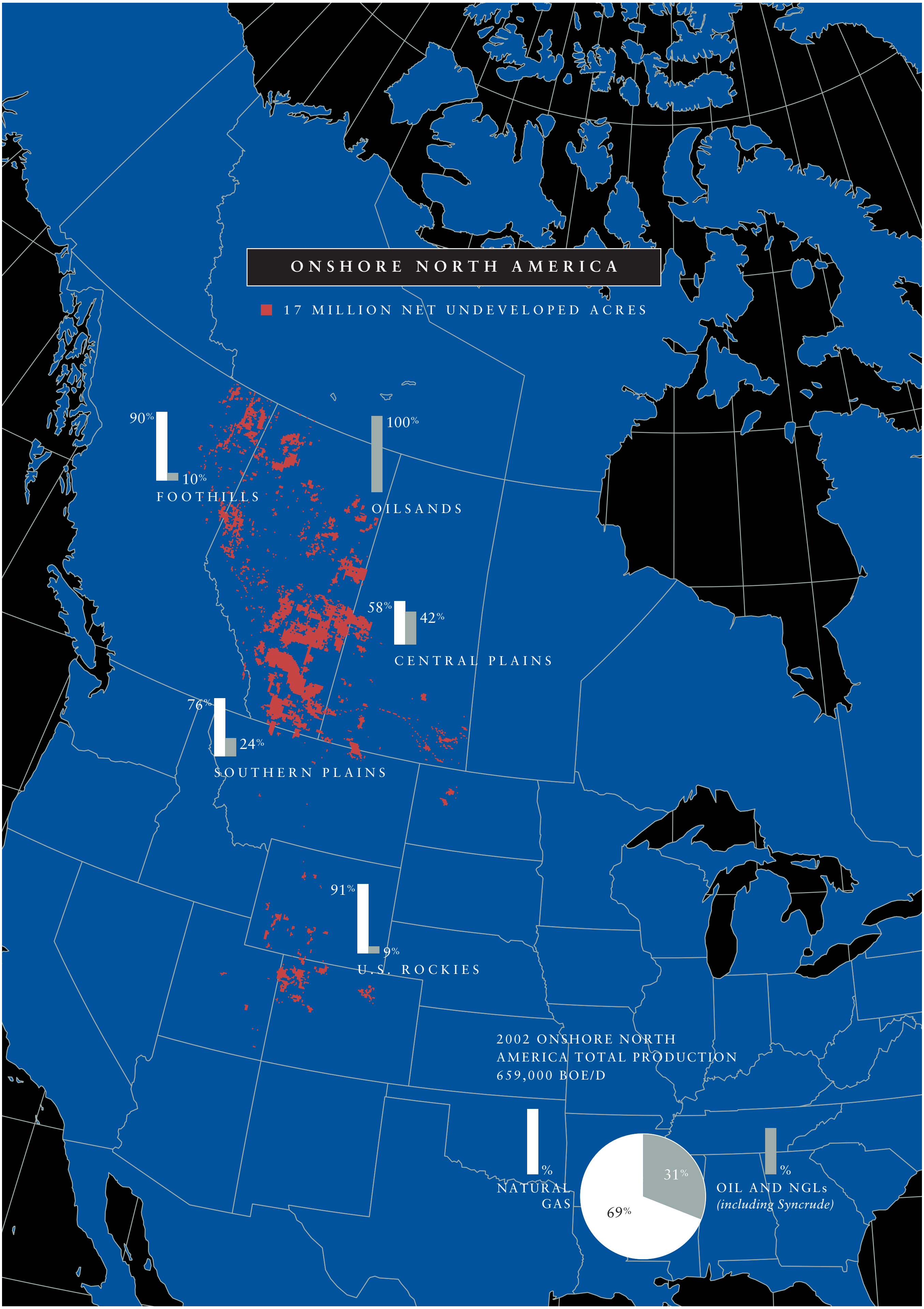
- 505 million cubic feet per day of natural gas production.
- 62,100 barrels per day of oil and NGLs production.
- 5.1 million net acres of undeveloped land.
- 2.2 million net acres of fee simple land.
- An average 97 percent interest in the petroleum and natural gas rights on approximately 846,000 net acres on the Primrose Block.

Strategy

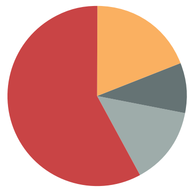
- Concentrate land position and activity in geographic areas of focus with multi-zone potential.
- Leverage expertise in horizontal drilling and waterflooding of oil reservoirs.

Pelican Lake – application of new ideas

Pelican Lake is the prime oil target within the Central Plains region. The key to freeing up this huge oil resource is taking conventional primary production to a secondary level with waterflooding. Production averaged about 13,900 barrels per day at Pelican Lake in 2002, however current recovery rates are just 5 percent. EnCana plans to double that rate in water-floodable areas, extracting another 40 million barrels. Initial pilot wells have seen a three-fold production increase from 60 to 200 barrels per day. Current plans are to convert about one-third of the 450 existing wells to water injectors and drill approximately 130 new horizontal producing wells by 2005. Recently, EnCana drilled a horizontal well that penetrated 2.9 kilometres through a three-metre-thick oil bearing formation. Such application of technology is opening up whole new areas of thin pay zones for resource capture at lower cost.


ONSHORE NORTH AMERICA
17 MILLION NET UNDEVELOPED ACRES
90%
10%
FOOTHILLS
100%
OILSANDS
58%
42%
CENTRAL PLAINS
76%
24%
SOUTHERN PLAINS
91%
9%
U.S. ROCKIES
2002 ONSHORE NORTH AMERICA TOTAL PRODUCTION 659,000 BOE/D
%
NATURAL GAS
31%
69%
%
OIL AND NGLs
(including Syncrude)

ONSHORE NORTH AMERICA
2002 UNDEVELOPED ACREAGE
(17 million net undeveloped acres)



- 58% Alberta
- 19% British Columbia
- 9% U.S. Rockies
- 14% Other

Defining Resource Potential: Those risked quantities of oil and gas which are estimated to be potentially recoverable on EnCana's existing land base from known accumulations and which are not currently classified as proved or risked-probable reserves.

6 OILSANDS

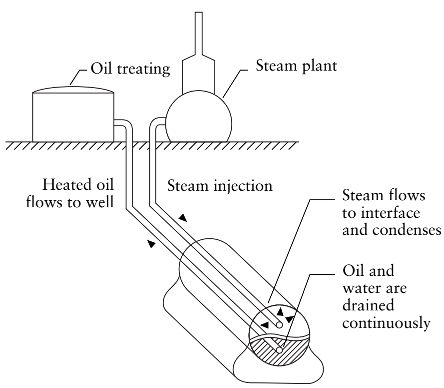
2002 Profile

- 31,500 barrels per day of conventional oil production.
- World's first large-scale commercial SAGD operation at Foster Creek.
- Second SAGD project now producing at Christina Lake.

Strategy

- Be the low-cost producer.
- Target low full-cycle steam-to-oil ratio of 2.5X reducing to 2.0X.
- Target highest quality reservoirs.
- Ensure scalability and repeatability of projects.
- Implement a downstream strategy and grow by manageable increments.

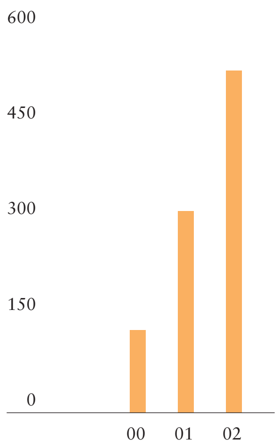
SAGD Process
Oilsands Region



Oilsands – technologically advanced barrels

EnCana's oilsands strategy is simple: select the best reservoirs, ones with identifiable growth potential, then apply assembly-line techniques that deliver reliable performance and drive down costs. It is well known that Canada's oilsands resources rival the reserves of Saudi Arabia. The challenge is that the oil in oilsands deposits is thick and viscous, requiring enhanced extraction methods. EnCana is a world leader in the most technically advanced means of profitably extracting heavy oil from underground oilsands formations – steam-assisted gravity drainage (SAGD). At Foster Creek, the world's first and largest producing commercial SAGD project, production is set to increase from the phase one design capacity of 20,000 barrels per day to approximately 30,000 barrels per day in 2004. EnCana's second project, Christina Lake, is a pilot project that is currently producing about 3,300 barrels per day. Along the way, the Company is continuing to improve the technology, looking for new ways to reduce its steam needs by blending in butane as a solvent or injecting propane in place of steam to increase recovery rates. EnCana is developing marketing solutions for its growing SAGD production.

U.S. ROCKIES GAS PRODUCTION
MMcf/d (pro forma)



7 U.S. ROCKIES

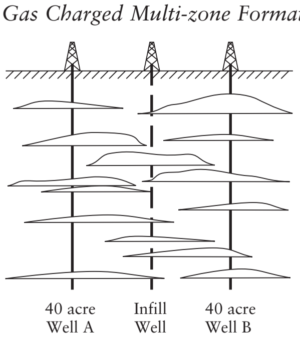
2002 Profile

- 500 million cubic feet per day of natural gas production.
- 8,200 barrels per day of oil and NGLs production.
- 1.5 million net acres of undeveloped land.
- Analagous to Suffield/Palliser areas, providing opportunity to apply existing core competencies.
- Inventory of more than 1,000 drilling locations.
- Low operating costs of less than $0.40 per thousand cubic feet.

Strategy

- Focus on deep, tight, multi-zone gas exploitation in large resource plays.
- Leverage infrastructure through down spacing.
- Be positioned to make opportunistic acquisitions.
- Identify exploration potential.

Gas Charged Multi-zone Formation

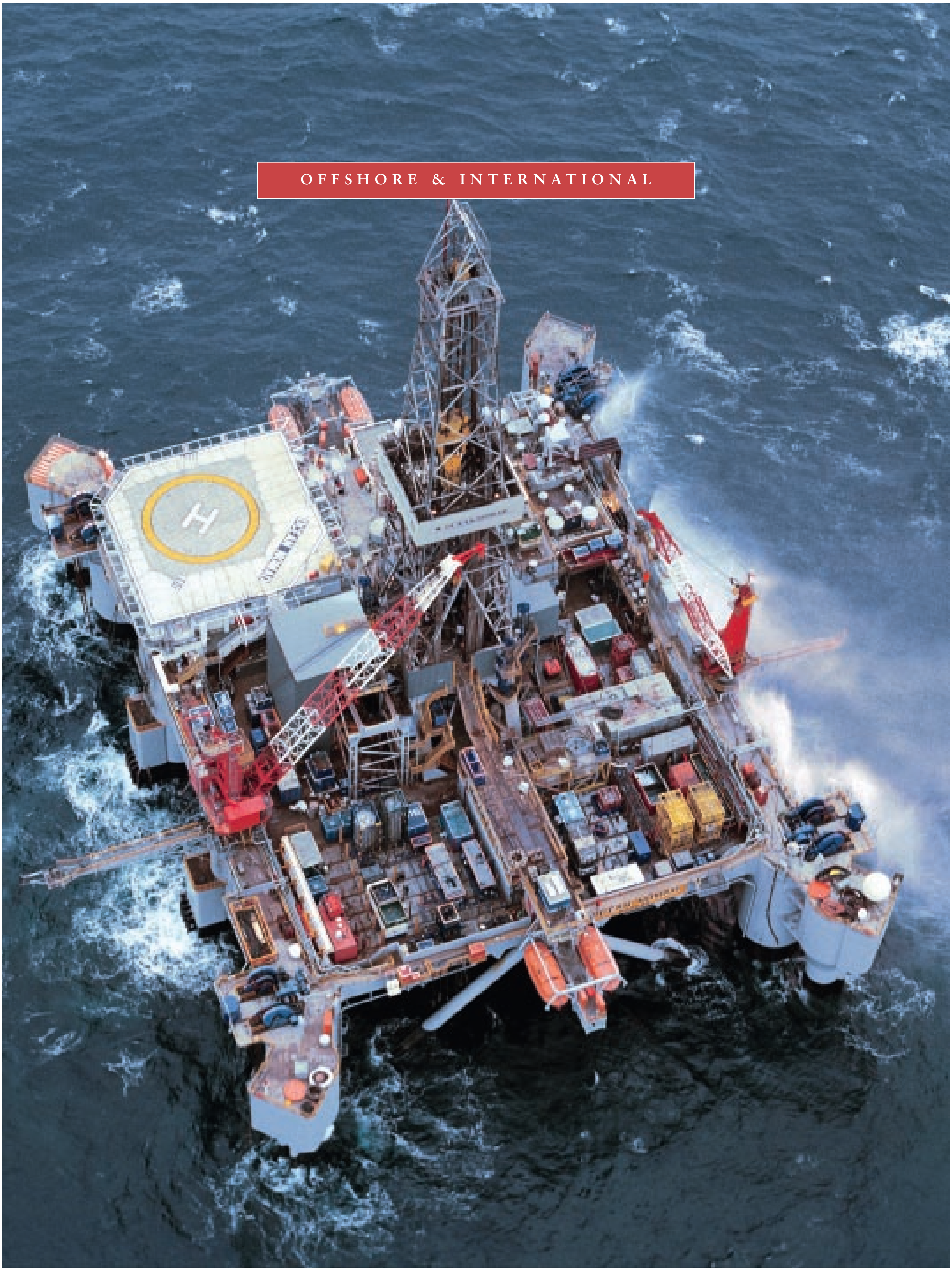


U.S. Rockies – Resource capture through acquisitions and extensions

In less than three years, the U.S. Rockies has become a cornerstone region for EnCana through profitable growth in production and reserves. Operations are focused on two prolific fields: the Jonah field in southwest Wyoming and the Mamm Creek field in the Piceance Basin of northwest Colorado. Since entering the U.S. Rockies in 2000, EnCana's annualized average daily gas production has risen from 93 million cubic feet in 2000 to 500 million cubic feet in 2002, comprised about equally of organic growth and acquisitions. In 2002, EnCana completed two U.S. Rockies acquisitions, increasing its Jonah interest to about 75 percent and adding production and reserves in the Piceance Basin. This multi-zone, tight gas region is one of EnCana's leading growth engines, and it is early in its life. Wells typically intersect 3,000 feet of gas charged, multi-formation reservoir. With an inventory of more than 1,000 known well locations, the area has great potential.

"In a very short period of time, EnCana has become a leading natural gas producer in the U.S. Rockies, a region that holds tremendous resource potential where we can apply our deep, tight, multi-zone exploitation core competency to deliver long-term value for EnCana shareholders."

Randy Eresman
Chief Operating Officer
EnCana Corporation



▲ *Appraisal drilling at Buzzard, the U.K. central North Sea is one of EnCana's high-impact exploration regions*

Vision: A SUCCESSFUL EXPLORER AND DEVELOPER OF HIGH-IMPACT RESERVES AND PRODUCTION IN SELECT OFFSHORE AND INTERNATIONAL LOCATIONS

Goal: MEANINGFUL AND PROFITABLE PRODUCTION GROWTH OVER THE MEDIUM AND LONG TERM FROM DISCOVERY AND DEVELOPMENT OF LARGE-SCALE RESERVES

"We will be both agile and disciplined in converting exploration success into producing assets that grow value for our shareholders."

Dave Boone
President,
Offshore & International
Operations Division

OFFSHORE & INTERNATIONAL

Strategy and Competitive Advantages

EnCana's Offshore & International teams have achieved substantial exploration success that will deliver high-impact growth in the near, medium and long term. The opening of Ecuador's Oleoducto de Crudos Pesados (OCP) export pipeline in mid-2003 will mark a step change for EnCana's Ecuador operations, as we look to increase our Oriente Basin production to an estimated 90,000 barrels per day by year-end. In subsequent years, development of EnCana's exploration successes at the Buzzard light oil discovery in the U.K. central North Sea, and the Tahiti and Llano oil finds in the Gulf of Mexico will provide medium- and longer-term, high-impact growth.

Our Offshore & International strategy parallels the consistent approach we have employed to build our successful North American operations. We typically start with a large land position, having assembled approximately 77 million net acres of undeveloped land on six continents. We apply our core competencies in geology, geophysics, technology and project management, obtain or influence operatorship in order to pace development and control costs, then focus and deliver. As major offshore and international discoveries progress towards development, they are reviewed regularly to ensure that each project meets strict value creation criteria and competes for capital among all development opportunities.

To provide long-term growth, EnCana's New Ventures team pursues high-impact exploration opportunities in highly prospective basins offering attractive fiscal terms. Approximately 10 percent of the Company's annual capital investment is directed to high-impact exploration. Essential to this strategy is a program of continuously high-grading our portfolio.

OFFSHORE & INTERNATIONAL regions in Ecuador and the U.K. central North Sea combine to produce approximately 62,000 barrels per day of oil. Exploration success in the Gulf of Mexico, the U.K. central North Sea and offshore East Coast Canada provide medium-to longer-term production growth while New Ventures exploration pursues further exploration success from its inventory of high-impact prospects.

"We conduct a consistent risk and resource assessment process to rank all of our opportunities. We then apply rigorous economic modelling to all of our prospects and ensure that they meet minimum corporate hurdle rates on a fully-risked basis."

Gerry Macey
President,
Offshore & New Ventures
Exploration Division

1 2002 HIGHLIGHTS *(pro forma)*

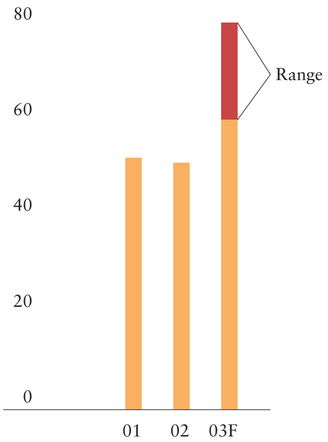
- Achieved oil sales of approximately 61,600 barrels per day.
- Successful appraisal drilling program at the EnCana operated Buzzard field. Current estimates of the field's original oil-in-place range between 800 million barrels and 1.1 billion barrels of oil. EnCana holds a 45 percent and 35 percent interest in the two blocks covering this field.
- Major oil discovery at Tahiti in the deep water Gulf of Mexico.
- Blackhorse discovery near the Scott field in the U.K. central North Sea.
- EnCana and partners were the successful bidders on five exploration blocks in the U.K. central North Sea.
- The Annapolis discovery, the first in the deep waters offshore Nova Scotia, encountered approximately 30 metres of natural gas pay over several zones.
- 'Tuck-in' acquisition in Ecuador adds approximately 600,000 net undeveloped acres and 4,600 barrels per day of production on Blocks 14, 17 and Shiripuno (transaction closed in early 2003).

2 GOALS FOR 2003

- Achieve average annual oil sales of between 65,000 and 90,000 barrels per day.
- Sanction the Buzzard development project.
- Drill 20 to 25 high-impact exploration wells in select international locations.

ECUADOR OIL SALES

Mbbls/d (pro forma)



F = Forecast

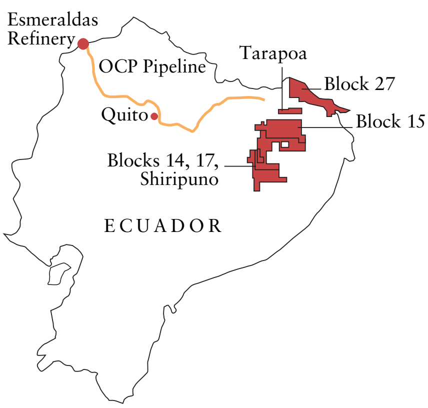
3 ECUADOR

2002 Profile

- 51,000 barrels per day of oil production.
- 766,000 net acres of undeveloped land.
- 213 million barrels of proved reserves.

Strategy

- Leverage Canadian heavy oil technical expertise.
- Target production growth to fill OCP pipeline capacity.
- Drive down capital costs and unit operating costs.
- Maintain environmental leadership position.



Ecuador – On the cusp of a major step change

EnCana entered Ecuador in 1999 with two goals in mind; help build a 500-kilometre oil export pipeline across the Andes Mountains to deliver stranded and landlocked oil reserves, and then grow production. Four years later, EnCana's vision is about to materialize. In a few months, Ecuador will open the largest infrastructure project in the South American country's history – the Oleoducto de Crudos Pesados (OCP) export pipeline. At a capacity of 450,000 barrels per day, OCP will be capable of shipping EnCana's planned doubling of its current Ecuador production volumes when it opens in mid-2003. Ecuador cleared the way for this project by allowing foreign companies to invest in Ecuadorean oil pipelines. EnCana, the largest private oil investor in Ecuador and a 31.4 percent owner of OCP, has overcome the challenges of operating in a developing country by applying best-in-class practices in drilling, production, safety and environmental care. EnCana is applying Canadian heavy oil expertise to extract the potential of the Oriente Basin and increase daily production from the region beyond 100,000 barrels per day. Exploration and EnCana's recent acquisition of three neighboring production blocks will generate future growth.

4 U.K. CENTRAL NORTH SEA

2002 Profile

- 10,500 barrels per day of net oil production from Scott and Telford fields.
- 414,000 net acres of undeveloped lands.
- Major light oil discovery at Buzzard, operated by EnCana with a 45 percent and 35 percent interest in the two blocks containing net recoverable oil estimated at 180 million barrels; six-well appraisal drilling program involved two rigs working simultaneously; estimated peak production of 75,000 barrels per day net to EnCana; first oil targeted 2006.
- Exploration success at Blackhorse.
- Additional exploration potential with plans to drill at least five exploration wells per year.
- Acquired five blocks, four licences totalling over 48,000 net acres in 20th Licensing Round.

Strategy

- Establish EnCana as a growing North Sea producer, particularly in the core area around Buzzard.
- Grow net operated production through continued exploration and strategic acquisitions.

OFFSHORE & INTERNATIONAL
2003 FORECAST CAPITAL INVESTMENT
PROFILE BY COMMODITY
($1 billion)

- 85% Oil
- 15% Gas

OFFSHORE & INTERNATIONAL
2003 FORECAST CAPITAL INVESTMENT
PROFILE BY REGION
($1 billion)

- 28% Ecuador
- 23% Gulf of Mexico
- 17% United Kingdom
- 15% East Coast
- 17% Other New Ventures

5 PORTFOLIO OF OPPORTUNITIES

Buzzard – Stratigraphic traps hold significant upside

For some time, the U.K. central North Sea has been considered a basin on decline with few remaining opportunities. Interest from the industry's majors has waned as high-impact finds were deemed unlikely. Then came EnCana's explorers with ideas for a new generation of stratigraphic traps in a region that was known to only surrender large reserves from structural geological plays. Applying a new idea in an old basin produced the world-class Buzzard field in 2001 – described by the U.K. energy minister as "possibly the largest discovery in 25 years." During 2002, EnCana successfully completed an extensive Buzzard appraisal program that increased the original oil-in-place estimate. The front-end engineering and platform design is near completion as EnCana moves the project towards regulatory approvals by mid-year and a forecast on stream date of 2006. While these development efforts are ongoing, exploration work continues to examine new prospects and EnCana remains an opportunistic acquirer as it builds a core production region in the U.K. central North Sea.

2002 Profile

Gulf of Mexico

- Light oil exploration discoveries in deep water at Llano and Tahiti; operator of the Tahiti discovery estimates total recoverable oil at between 100 and 125 million barrels, representing EnCana's 25 percent net interest.
- EnCana working interest lands total more than 510,000 net acres.
- Strong portfolio of exploration prospects.
- More than 40 deep water prospects.
- Llano proceeding with first oil targeted in 2004.

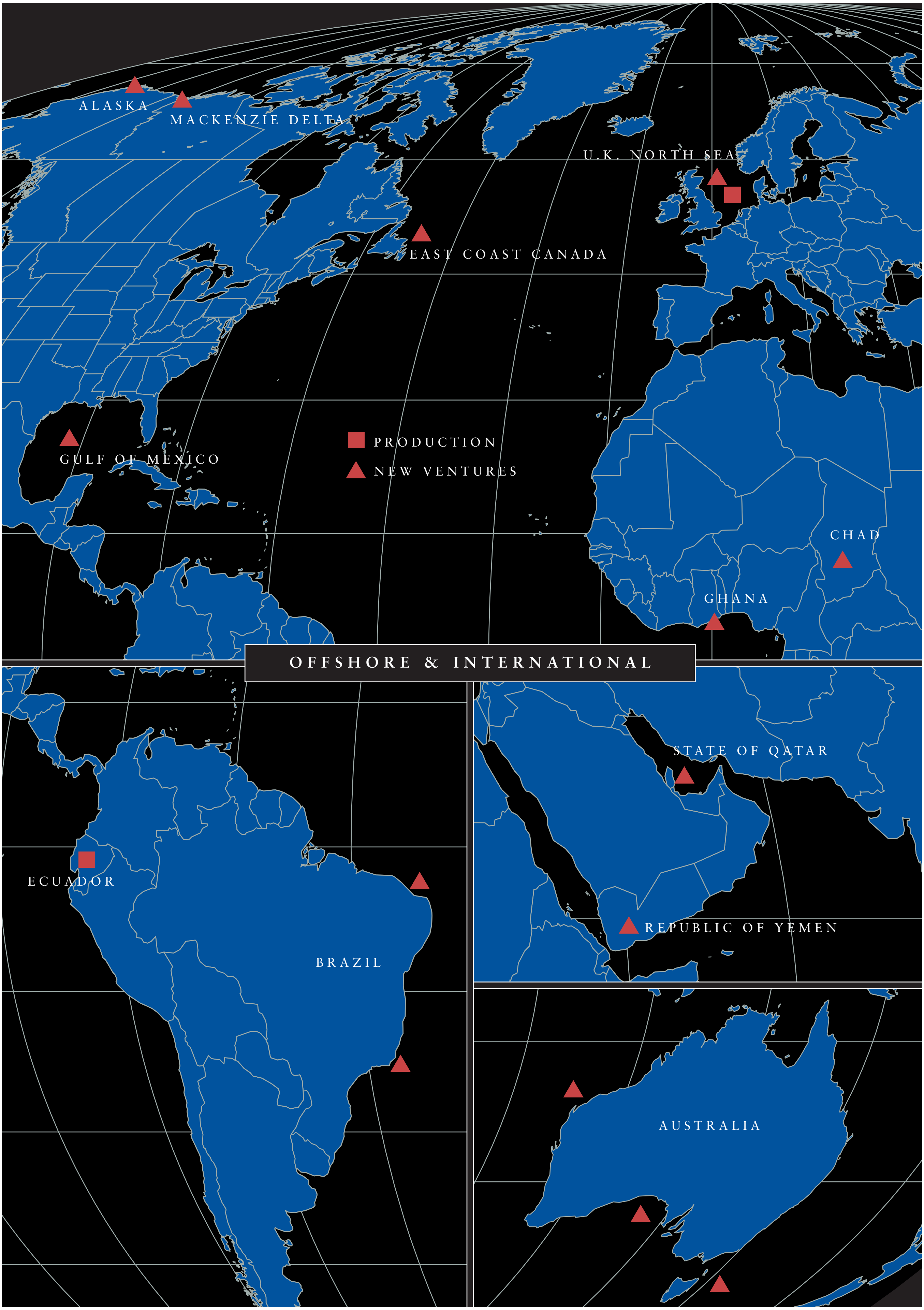
East Coast Canada

- Largest offshore land position in Atlantic Canada – 27 exploration licences, 21 of which are operated, with 3.1 million net acres in offshore Nova Scotia and 2.8 million net acres in Newfoundland and Labrador.
- 100 percent working interest in the large appraised carbonate gas discovery at Deep Panuke in shallow water offshore Nova Scotia; potential new hub in frontier basin with large upside; anchors East Coast Canada growth platform.

2002 Profile

Offshore & New Ventures Exploration

Besides its core production in North America and the development of major discoveries in emerging core regions, EnCana has a highly specialized team of explorationists cultivating a highly-prospective inventory of New Ventures Exploration targets in select locations. New Ventures activities are being conducted in Alaska, Australia, Brazil, Chad, East Coast Canada, Ghana, the Gulf of Mexico, Mackenzie Delta, the Middle East and the U.K. EnCana plans to drill 20 to 25 potentially-significant wells in these regions each year, looking for its next Buzzard or Tahiti.


ALASKA
MACKENZIE DELTA
U.K. NORTH SEA
EAST COAST CANADA
GULF OF MEXICO
PRODUCTION
NEW VENTURES
CHAD
GHANA
OFFSHORE & INTERNATIONAL
STATE OF QATAR
ECUADOR
BRAZIL
REPUBLIC OF YEMEN
AUSTRALIA

Vision: PROVIDE BEST-IN-CLASS MARKETING INTELLIGENCE AND STRENGTHEN ENCANA'S POSITION AS THE CONTINENT'S LARGEST INDEPENDENT GAS STORAGE OPERATOR

Goal: CAPTURE MAXIMUM VALUE THROUGH STRATEGIC MARKETING OF ENCANA'S OIL AND GAS PRODUCTION AND TARGETED MIDSTREAM INVESTMENTS

"Our marketing expertise and selective midstream investments capture opportunities and provide a competitive advantage along the EnCana value chain."

Bill Oliver
President,
Midstream & Marketing Division

MIDSTREAM & MARKETING

Strategy and Competitive Advantages

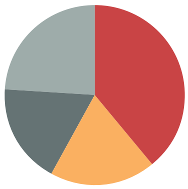
In Midstream & Marketing we are focused on continually enhancing our knowledge and understanding of oil and gas market fundamentals to capture the best possible price for our products, and on using our midstream assets to enhance the value of our core upstream operations.

The strategic marketing focus in all our efforts is to maximize value/netbacks in each of our upstream business units and to develop value creation opportunities that support our stated upstream growth targets.

EnCana's integrated North American natural gas strategy combines our high-growth North America gas production with the continent's largest independent gas storage capacity. Our gas storage group combines the highest quality storage reservoirs and facilities, a market-oriented business model and industry-leading technical and commercial optimization skills to capture added value by managing our inventory and adjusting sales on a seasonal basis. EnCana's current storage capacity is about 145 billion cubic feet. New projects and expansions currently under construction will add approximately 55 billion cubic feet of working gas capacity and increase withdrawal capability to more than 4 billion cubic feet per day by 2005. As one of the few upstream companies in the natural gas storage industry, EnCana has achieved competitive advantages by pioneering the application of upstream technologies, such as the use of horizontal wells, to achieve high rates of deliverability from reservoir storage facilities. This huge capacity, combined with technical expertise, widespread facilities and a current withdrawal capacity of about 2.7 billion cubic feet per day, provides EnCana with unique flexibility and a competitive market edge.

Midstream operations also include ownership and operatorship of natural gas liquids extraction facilities and gas-fired power plants each leveraging the market value of EnCana's core exploration and production.

MARKETING
2003 FORECAST CONVENTIONAL OIL AND NGLs SALES BY REGION
(240,000 to 280,000 barrels per day)



- 39% U.S. Padd 2
- 19% Canada
- 18% U.S. Padd 4
- 24% Other

MARKETING
2003 FORECAST NATURAL GAS SALES BY REGION
(3.0 to 3.1 billion cubic feet per day)

- 47% Western Canada (AECO)
- 25% U.S. Rockies
- 12% U.S. Midwest
- 16% Other

3 GOALS FOR 2003

- Complete first phase of Countess gas storage construction and commence the first phase of operation.
- Complete the first phase of the Wild Goose gas storage expansion.
- Target OCP completion and begin flowing EnCana production by mid-2003.

1 2002 HIGHLIGHTS *(pro forma)*

- Started construction of Countess gas storage facility located in south central Alberta on the Palliser Block; 40 billion cubic feet of storage capacity; peak withdrawal rate of 1.25 billion cubic feet per day; facilities expected to reach full capacity by 2005.
- Expanding Wild Goose gas storage in California; current storage capacity of 14 billion cubic feet; expanding to 29 billion cubic feet; current withdrawal rate of 200 million cubic feet per day increasing to 700 million cubic feet per day; first phase of expansion expected to be in service by April 2004.
- Advanced construction of OCP Pipeline with expected on stream date of mid-2003.
- Sold interests in two pipeline systems, Express and Cold Lake, for $1.6 billion in proceeds (transaction closed in January 2003).

2 FOCUS AREA

Gas Storage

EnCana combines the leading independent North America natural gas production position with the largest independent gas storage network to derive enhanced shareholder value from its asset base. EnCana applies its exploration and production expertise in the development of depleted reservoirs to capture value at various points in the natural gas value chain. The 100 percent owned AECO Hub™ is EnCana's anchor storage asset and a major pricing point for Western Canadian gas. It is comprised of the 85 billion cubic feet Suffield facility and the 10 billion cubic feet Hythe facility, and is currently being expanded with the construction of the 40 billion cubic feet Countess facility. In addition to contracting storage space to third parties, EnCana has the ability to inject its own produced gas during periods of weak prices. Storage optimization is a third component of EnCana's gas storage strategy, which allows the Company to take advantage of the unused storage capacity to enhance returns.

- 145 billion cubic feet of total working gas capacity
- 2.7 billion cubic feet per day of withdrawal capacity
- Expansions underway

The Corporation's Board of Directors and management support the Guidelines for Corporate Governance (the TSX Guidelines) adopted by the Toronto Stock Exchange (TSX) in 1995 and the Corporation's approach to corporate governance is in full compliance with the TSX Guidelines. In April 2002 and November 2002, the TSX published proposed amendments to the TSX Guidelines which have not at the time of printing of the Annual Report been adopted by the TSX. The Nominating and Corporate Governance Committee of the Board continues to monitor the proposed amendments to the TSX Guidelines, the proposed changes to the NYSE listing standards and other changes in applicable laws (including those adopted and proposed under the United States Sarbanes-Oxley Act of 2002*) and will take appropriate action in response to any new standards which are established.*

ENCANA seeks high standards of corporate governance and believes that it has adopted best practices in developing its approach to corporate governance. EnCana's Board is led by a non-executive chairman and comprises 16 Directors, 15 of whom are independent. The following is a summary of EnCana's Corporate Governance Practices. A more detailed description of the Corporation's practices can be found in the Corporation's Information Circular dated February 28, 2003.

STATEMENT OF CORPORATE GOVERNANCE PRACTICES

Mandate of the Board

The Board of Directors of EnCana exercises overall responsibility for the management and supervision of the affairs of the Corporation. This includes the appointment of the Chief Executive Officer and senior officers, approval of their compensation and monitoring of the Chief Executive Officer's performance. The Board has established administrative procedures which prescribe the requirements governing the approval of transactions carried out in the course of the Corporation's operations, the delegation of authority and the execution of documents on behalf of the Corporation.

The Board also reviews and adopts an annual strategic plan. Key objectives, as well as quantifiable operational and financial targets, and systems for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

The Board ensures that a process is established that adequately provides for succession planning, including the appointing, training and monitoring of senior management.

The Board also annually reviews a communications policy in relation to shareholders, employees, financial analysts, the media and other stakeholders. The policy contains procedures and practical guidelines for the consistent, transparent, regular and timely public disclosure of material and non-material information about EnCana.

Board Composition

The Board is currently composed of 16 Directors, 15 of whom are unrelated to the Corporation under the existing TSX Guidelines. Mr. Gwyn Morgan, EnCana's President & Chief Executive Officer, is the only Board member who is also a member of the Corporation's management.

"WE BELIEVE THAT THE ESSENCE OF GOVERNANCE IS ACCOUNTABILITY AND, BEYOND STRAIGHTFORWARD REGULATORY COMPLIANCE, WE STRIVE FOR MEANINGFUL DISCLOSURE AND TRANSPARENT FINANCIAL MANAGEMENT."

David P. O'Brien
Chairman, EnCana Corporation

BOARD COMMITTEES

The Board annually appoints members to Board committees in the following six areas: Nominating and Corporate Governance; Audit; Reserves; Corporate Responsibility, Environment, Health and Safety; Human Resources and Compensation; and Pension. All of the committees are composed solely of non-management, unrelated directors (under the existing TSX Guidelines), with EnCana President & Chief Executive Officer Gwyn Morgan serving only as an ex officio, non-voting member of the Corporate Responsibility, Environment, Health and Safety Committee and the Pension Committee. Each of the committees has a Board-approved mandate which prescribes its composition and responsibilities as well as administrative duties.

Nominating and Corporate Governance Committee ("NCG")

The NCG Committee is responsible for identifying individuals qualified to become Board members, and recommending to the Board proposed nominees for election to the Board and Board compensation. The NCG Committee is also responsible for reviewing, reporting and providing recommendations for improvement to the Board with respect to all aspects of corporate governance. The NCG Committee has a Vice-Chairman who is responsible for chairing a meeting of the NCG Committee where the performance of the Chairman of the Board is reviewed. The NCG Committee, on a periodic basis, assesses the effectiveness of the Board as a whole, the committees of the Board and the contributions of individual members. As well, the committee is responsible for the orientation and education of new Board members and continuing development of existing Board members.

Audit Committee

The Audit Committee reviews, reports and provides recommendations to the Board on the annual and interim financial statements and on the integrity of the financial reporting of the Corporation; the adequacy of the Corporation's processes for identifying and managing financial risk; the adequacy of its internal control system; the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor; and the appointment and mandate of the internal auditor. The Audit Committee meets regularly in-camera with the internal auditor and the external auditor. The Audit Committee's mandate requires that the committee meet regularly with the external auditor without management present.

Reserves Committee

The Reserves Committee is responsible for reviewing the Corporation's externally disclosed oil and gas reserves estimates, including reviewing the qualifications of, and procedures used by, the independent engineering firms responsible for evaluating the Corporation's reserves.

Corporate Responsibility, Environment, Health and Safety Committee ("CREH&S")

The CREH&S Committee is responsible for reviewing, reporting and making recommendations to the Board on the Corporation's policies and procedures with respect to environment, occupational health, safety, security and overall corporate responsibility matters.

Human Resources and Compensation Committee ("HRC")

The HRC Committee reviews, reports and provides recommendations to the Board on the compensation of the Chief Executive Officer and the appointment and compensation of senior corporate officers, succession plans, the compensation policy for all other employees and the approval of all grants of stock options.

Pension Committee

The Pension Committee advises the Board on policy with respect to the administration and funding levels of the Corporation's Pension Plan and the selection of investment managers.

▲ *EnCana-sponsored community-centred medicinal herb garden in Ecuador*

Our Values

ENCANA'S HERITAGE COMPANIES BUILT EXEMPLARY REPUTATIONS FOR CONDUCTING BUSINESS WITH THE HIGHEST LEVEL OF INTEGRITY. BOTH COMPANIES EMBODIED STRONG VALUES AND SHARED A TRADITION OF SUCCESS UPON WHICH ENCANA IS BUILDING. NOW THAT THE COMPANIES HAVE INTEGRATED, ENCANA IS ENGAGED IN WRITING A CORPORATE CONSTITUTION THAT WILL DEFINE A CLEAR VISION OF WHAT ENCANA STRIVES TO ACCOMPLISH, ITS PRINCIPLES AND VALUES, AND THE WORK ENVIRONMENT ENCANA WILL CULTIVATE.

CORPORATE RESPONSIBILITY PROGRAMS

Environment, Health and Safety (EH&S) Management Program

EnCana's corporate EH&S Policy guides the development and implementation of divisional programs and practices. While compliance and EH&S performance remains a responsibility of the divisions, the corporate policy signals a company-wide commitment to EH&S performance.

EnCana is also finalizing a best-practices benchmark management system for assessing and improving the Company's EH&S performance called Environment, Health and Safety Best Practices. Its success rests in the quality of its ongoing execution, which will be regularly assessed commencing in the second half of 2003.

Under this management system, the main goals for the Onshore North America division include improving the performance of contractors providing services in the field and ensuring regulatory compliance of all operations. The main goal for the International divisions is to incorporate best practices into a comprehensive management system that includes EH&S and operations standards that reflect the complexities of offshore and international operations. For Midstream & Marketing, the goal is to implement the system at all our facilities to ensure best-practice performance.

EnCana's comprehensive Crisis Management Plan is continually tested in all operating areas and updated as required.

Community Investment Program

At EnCana, we believe in a capacity building partnership approach to investing in the communities where we operate. By partnering with our employees, not-for-profit organizations, community organizations and other businesses, we have an opportunity to sustain and improve relationships with our neighbours by enhancing community-related programs and by setting new benchmarks for environmental responsibility. To facilitate this program, EnCana applies the corporate giving formula of the Canadian Centre for Philanthropy – one percent of pre-tax profits on a five-year rolling average – and has established the 2003 Community Investment budget at $10 million for this inaugural year.

CORPORATE RESPONSIBILITY POLICY FRAMEWORK

At EnCana, corporate responsibility encompasses performance within environment, health, safety, community involvement, ethics and economic disciplines. The Company has reviewed emerging best practices in corporate responsibility policy and is now developing its policy framework into commitments, to be supported by guidelines within each of these disciplines. The target time frame to complete the Corporate Constitution and the Corporate Responsibility Policy is August 2003. While the Company has already developed specific instruments to address priority issues, this integrated corporate policy will link the values of our Constitution to the actions and corporate attitudes throughout the Company's operations and its corporate governance.

EnCana takes a capacity building partnership approach to investing in the communities where we operate.

The concept of the EnCana Cares Foundation is a model adopted by other Canadian companies.

CORPORATE RESPONSIBILITY PROGRAMS

Greater detail about EnCana's Community Investment guidelines, areas of focus and contributions can be found on EnCana's website: www.encana.com. The Community Investment program consists of three basic components:

1) EnCana Cares Foundation

The EnCana Cares Foundation is an employee-driven charitable foundation that provides an opportunity for our employees to donate, through cheque or payroll deduction, to registered Canadian charities of their choice. This is done through a company-wide annual campaign among Canadian employees. EnCana supports employee choices by matching their donations dollar-for-dollar, doubling the impact the employee makes to charities of their choice. In 2003, more than 480 organizations, including the United Way and its agencies, will benefit from approximately $1.4 million donated through this program. The concept of the EnCana Cares Foundation has been the subject of charitable funding and fundraising conferences and is a model adopted by other Canadian companies.

2) Matching Gifts Program

In addition to the 'pre-planned donations' of Canadian employees through the EnCana Cares Foundation, an ongoing Matching Gifts Program has been established for all employees world-wide. At-the-door gifts (or those not planned through the EnCana Cares Foundation) to non-profit and charitable organizations are matched on a quarterly basis. The program also matches employee pledges to, and/or participation in, various fundraising activities or events such as skate-a-thons and charity runs. The minimum level for matching is $25 and the maximum aggregate donation matched per employee is $25,000 per year.

3) Capacity Building Investments

The balance of EnCana's Community Investment program is applied to communities and regions where the Company operates. While contributions will support youth and education, health and wellness, environment, and community development priorities, the Company is particularly proud of its distinctive capacity building programs. In Canada, these programs are with First Nations and Metis communities and in Ecuador with local communities, as well as with environmental non-government organizations.

EnCana was recently recognized by Alberta's Chambers of Commerce, receiving the Aboriginal Relations Best Practice Award of Distinction. The Company served as the architect of an expanding concept of Aboriginal rig ownership in partnership with exploration drilling companies that support EnCana's extensive annual drilling program. A successful pilot project was conducted in 2001, in which four First Nations teamed up with Precision Drilling, Indian and Northern

Building a legacy of sustainable livelihoods in rainforest communities.

Affairs Canada, and the Alberta departments of Aboriginal Affairs and Human Resources and Employment to help the First Nations own a new rig and train their young people as operators. During 2002, EnCana and Lakota Drilling partnered to develop similar opportunities for other Aboriginal communities. The Dene Tha' First Nation of northwest Alberta opted to participate with two of four rigs available; the Metis Federation of Alberta adopted another rig and the Saddle Lake Band First Nation closed the deal on the fourth rig. All rigs are operational, providing on-the-job management and operational training for Aboriginal people. EnCana's role was to assist in bringing the partners together, and to commit four years of work, at annually competitive industry rates, for the rigs.

Fundación ÑanPaz

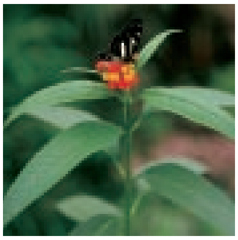
Fundación ÑanPaz in Ecuador has helped EnCana establish programs to build a legacy of sustainable livelihoods in the rainforest communities where the Company operates. This capacity building approach is focused on increasing the sustainability of local groups and individuals, and geared to the realities of living in the Amazon. ÑanPaz works with the Company's community relations strategy in seeking greater co-operation with like-minded Ecuadorean non-governmental agencies to maintain effective programs and pilot new concepts.

In addition to the more traditional community assistance programs such as providing health clinic services and building schools, initiatives include:

- the development of a pilot integrated farm to illustrate an effective and efficient approach toward agriculture in the rainforest, reducing the amount of land required for a sustainable operation, and demonstrating the opportunity to increase, for some operators, annual revenues tenfold;
- the establishment of an eco-tourism park. "Howler's Shelter" is a small area of four hectares of blackberry plants and virgin forest in the zone where various unique vegetation and animal species can be found such as the howling and the "muddy" monkeys, as well as a large quantity of insects, butterflies, large parrots, toucans, hanging nest birds, small caimans, tarantulas and orchids;
- the introduction of a land reforestation program using two tree species – Jacaranda and Mahogany – to create additional economic resources in 5-year and 20-year harvest increments;
- the provision of trained agricultural extension advisors to assist local producers in addressing problems in their own operations;
- the establishment of a community-centred medicinal herb garden and the provision of an Andean herbalist to community residents who wish to establish their own gardens;
- the launching of a permaculture program in 11 schools whereby students plant and tend a school vegetable garden, harvest and dry the seeds for replanting. They also enjoy the enhanced nutrition of noontime meals in EnCana-sponsored kitchens that were added to the schools. This program, and one which sponsors more than 100 underprivileged students to stay in school, is conducted jointly with the National Institute for Children and the Family, and with the United Nations World Food Programme.

The Company is also sponsoring, with the Canadian EnerGreen Foundation and Ecuador's Fundación Natura, a program to begin replacing the use of diesel-generated electricity with solar panels on the Galapagos Islands. EnCana is evaluating the introduction of a proven and simple biosand filtration process for individual abodes or as central water treatment facilities in distant communities.

The Ecuador Ministry of Environment bestowed upon EnCana the "Ministry of Environment Award," the highest honour given by the Secretariat of State to a private company in recognition of our environmental and social programs.



The establishment of an eco-tourism park is an EnCana sponsored initiative.

EnCana's Response to Kyoto: Late in 2002, EnCana supported a Made in Canada approach toward the reduction of greenhouse gas emissions, convinced that this approach would be far more effective than Canada's signing of the Kyoto Protocol. EnCana is already demonstrating industry leadership through a number of programs in its operations, as reported in the Voluntary Challenge Registry and exemplified by the Weyburn CO_2 miscible flood project in Saskatchewan.

ENVIRONMENTAL PROGRAMS

Alberta EcoTrust

Alberta EcoTrust Foundation is a non-government agency comprising representatives of Alberta environmental organizations and industry for the purpose of supporting grassroots environmental projects. This collaborative partnership of people and organizations reaffirms the belief that the environment is integral to a strong and successful community.

EnCana, a long-term supporter of Alberta EcoTrust, announced in 2003 the commencement of a 25-year pledge to Alberta EcoTrust. This $1.25 million will fund environmental projects in smaller communities and help the Foundation explore expansion to other provinces in Canada such as British Columbia, Saskatchewan and Nova Scotia.

SAIT Environmental Technology Centre

The Southern Alberta Institute of Technology (SAIT) established the Environmental Technology Centre in order to meet the needs of business and industry. The Centre presents customized training to industry leaders, as well as courses to full-time degree and diploma students. EnCana is proud to be the lead sponsor of the Environmental Technology Centre with a grant of $250,000, part of a comprehensive $1.5 million program which supports SAIT's Networked Learning capability to attract students from around the world to its much-respected petroleum industry and other training modules.

The environmental business sector is one of the fastest growing areas of the provincial and world economies. While environmental remediation remains a priority, industry is, through the creation of new processes and technologies, becoming more proactive in lightening its footprint and preventing environmental problems.

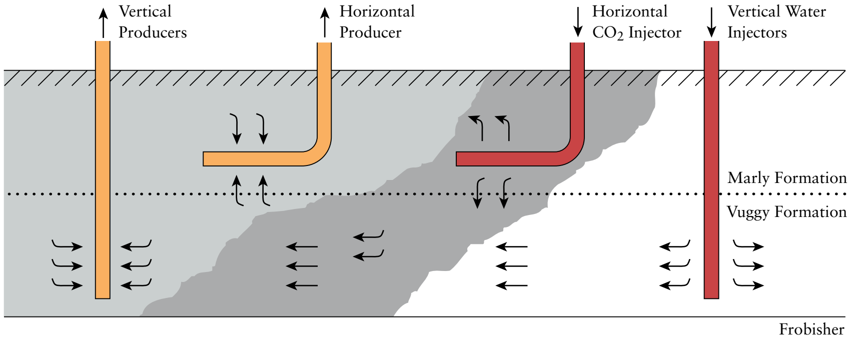
Ecuador Eco-Fund

Oleoducto de Crudos Pesados (OCP) Ecuador S.A. and a group of environmental Non-Governmental Organizations (NGOs) agreed on the creation of an Ecological Fund (Eco-Fund) with an initial multi-year capital funding commitment of US$17 million to be used in the development of environmental projects, training, scientific research, and conservation projects in Ecuador.

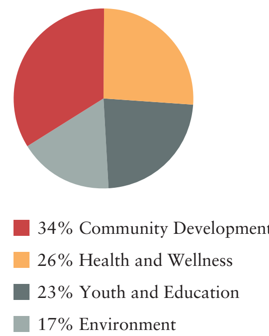
While the bulk of the initial funding comes from OCP through its seven corporate sponsors, including EnCana, an additional financial commitment was made by EnCana to anchor the Fund and ensure it had sufficient support in the early years. This boost enables the NGOs to initiate some significant research and conservation programs to further enhance Ecuador's protection of its national environment. EnCana's contribution will be approximately 30 percent of the total. These participating NGOs have also committed to adding 30 percent through their own fundraising campaign.

The Ecuador Eco-Fund's investment program can apply to sustainable development programs in the OCP construction zone, as well as the oil producing Northern and Central areas of the Amazon region.

Weyburn CO_2 Miscible Flood Project



2002 COMMUNITY INVESTMENT
($8.3 million)



EnCana is focused on contributing to the strength and sustainability of the communities in which we are privileged to operate.

Voluntary Challenge & Registry Inc.

The Voluntary Challenge & Registry Inc. (VCR Inc.) is a non-profit partnership between industry and governments across Canada. Its mission is to provide the means for promoting, assessing, and recognizing the effectiveness of the voluntary approach in addressing climate change. EnCana has been recognized at the Gold level, and our latest annual report to VCR Inc. can be found at www.vcr-mvr.ca

VCR Inc. recruits broad participation from all sectors of the Canadian economy with the support of the Council of Champions and in conjunction with sector organizations. It records, documents, and analyzes participation, action plans, best practices, and achievements to consider their potential for further progress and to provide the related support as participants' involvement deepens. VCR recognizes, publicizes, and promotes participants making significant progress towards Canada's greenhouse gas (GHG) emissions reduction objectives with the support of its Technical Advisory Committee. It also contributes to the development and implementation of standards and procedures for measuring the impact of GHG reduction activities. VCR Inc. provides a national registry for initiatives, which led to early voluntary action to reduce GHG.

Weyburn, Saskatchewan CO_2 Miscible Flood Project

The Weyburn oilfield covers over 70 square miles in southeastern Saskatchewan and is one of the largest medium-sour crude oil reservoirs in Canada, containing approximately 1.4 billion barrels of original oil in place. Discovered in 1954, the field was on waterflood from 1964 to 2000, and has been on CO_2 miscible flood since 2000. A CO_2 miscible flood differs from waterflood injection in that a waterflood is used to increase reservoir pressure in an effort to improve production. A miscible flood is an enhanced oil recovery technique where a fluid (CO_2) is injected into the reservoir to expand and sweep the oil to the producing wells.

Over the life of the project, net CO_2 emissions will be reduced by an estimated 14 million tonnes, which is equivalent to taking about 3.2 million cars off the road for one year. The Weyburn field is also the site of a major international research study conducted under the auspices of the International Energy Agency Greenhouse Gas Research & Development Program. The CO_2 monitoring project is unique because scientists and researchers collected background information before the oilfield was flooded with CO_2. This information will enable them to compare before and after results and help them better understand the interaction and relationships between oil recovery and CO_2 sequestration.

ENCANA CORPORATION

Entering^2

ENTERING A NEW ERA

▲ *EnCana shares open for trading on the NYSE on April 8, 2002. Dick Grasso, NYSE Chairman and CEO; Gail and David O'Brien, EnCana Chairman; Jamie Salé and David Pelletier, Canadian Olympic gold medallists; Georges Ugeux, NYSE Senior Managing Director, International.*

ENCANA FINANCIAL PERFORMANCE

In the interest of providing EnCana shareholders and potential investors with information regarding the Company, certain statements throughout this 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*. Readers are referred to the Advisory on the Inside Back Cover of this Annual Report for more detail regarding forward-looking statements.

This Management's Discussion and Analysis ("MD&A") for EnCana Corporation ("EnCana" or the "Company") should be read in conjunction with the audited consolidated financial statements and accompanying notes on pages 65 to 100 of this annual report. The Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation to United States GAAP is included in Note 23 to the Consolidated Financial Statements.

OVERVIEW

On January 27, 2002, PanCanadian Energy Corporation ("PanCanadian") and Alberta Energy Company Ltd. ("AEC") announced that their respective Boards of Directors had unanimously agreed to merge the two companies.

On April 5, 2002, PanCanadian and AEC completed this merger, 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. Further information with respect to the merger transaction is contained in Note 3 to the audited consolidated financial statements ("Consolidated Financial Statements").

The Consolidated Financial Statements include the results of AEC from April 5, 2002, the closing date of the merger. As such, the amounts reported for the year ended December 31, 2002 reflect twelve months of PanCanadian results combined with the nine months of post merger AEC results. The comparative figures are based solely on the 2001 and 2000 results of PanCanadian.

EnCana reports the results of its operations under two main business segments: Upstream and Midstream & Marketing. The Company's Upstream business segment consists of the Onshore North America, Offshore & International Operations and the Offshore & New Ventures Exploration divisions. Onshore North America includes EnCana's North America onshore exploration for, and production of, natural gas, natural gas liquids and crude oil. The Offshore & International Operations division develops the reserves associated with offshore and international discoveries. The division currently has production in Ecuador and the U.K. central North Sea and major developments in the East Coast of Canada, Gulf of Mexico and the U.K. central North Sea. The Offshore & New Ventures Exploration division includes the Company's exploration activity in the Canadian East Coast, the North American frontier region, the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia and Latin America. The Company's Midstream & Marketing business segment includes gas storage operations, natural gas liquids processing and power generation operations, as well as marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

CONSOLIDATED FINANCIAL RESULTS

EnCana's cash flow from continuing operations of $3,779 million, or $8.89 per common share-diluted ("per share"), marked an historic year of record level cash flow, compared with $2,259 million, or $8.63 per share, in 2001 and $2,278 million, or $8.86 per share, in 2000. The higher 2002 cash flow was the result of increased revenues, due primarily to growth in sales volumes and lower cash tax expense, which were offset by higher costs for transportation and selling, operating, purchased product, administration and interest.

2002 net earnings from continuing operations were $1,225 million, or $2.87 per share, compared with $1,254 million, or $4.77 per share, in 2001 and $1,000 million, or $3.87 per share, in 2000. Earnings in 2002 were affected by significantly weaker Western Canada and U.S. Rockies regional ("regional") natural gas prices. The effect of the lower 2002 regional gas prices was partially offset by an increase in sales volumes resulting from the merger and the Company's expansion of its Onshore North America operations.

As discussed in Note 2 to the Consolidated Financial Statements, the Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate. Resulting foreign exchange gains or losses are recorded in the Consolidated Statement of Earnings, or in the case of long-term debt contained in self-sustaining foreign operations, in the foreign currency translation account included in Shareholders' Equity in the Consolidated Balance Sheet. In order to provide shareholders and potential investors with information clearly presenting the effect of the translation of the outstanding U.S. dollar debt on the Company's results, the following table has been prepared:

($ millions)	2002	2001	2000
Net earnings, as reported	$ 1,224	$ 1,287	$ 1,021
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	27	(44)	(29)
Earnings, excluding foreign exchange on translation of U.S. dollar debt	$ 1,197	$ 1,331	$ 1,050
($ per common share – diluted)			
Net earnings per common share – diluted, as reported	$ 2.87	$ 4.90	$ 3.95
Deduct: Foreign exchange gain (loss) on translation of U.S. dollar debt (after-tax)*	0.06	(0.17)	(0.11)
Earnings, excluding foreign exchange on translation of U.S. dollar debt per common share – diluted	$ 2.81	$ 5.07	$ 4.06

* As this is an unrealized gain (loss) there is no impact on cash flow.

Earnings, excluding foreign exchange on the translation of U.S. dollar debt, and cash flow per share are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this discussion and analysis in order to provide shareholders and potential investors with additional information regarding the Company's finances and results of operations.

Consolidated Financial Summary *($ millions, except per share amounts)*	2002	2001	2000
Revenues, net of royalties and production taxes	$ 10,011	$ 4,894	$ 4,366
Net earnings from continuing operations	1,225	1,254	1,000
– per common share-diluted	2.87	4.77	3.87
Net earnings	1,224	1,287	1,021
– per common share-diluted	2.87	4.90	3.95
Cash flow from continuing operations	3,779	2,259	2,278
– per common share-diluted	8.89	8.63	8.86
Cash flow	3,821	2,306	2,303
– per common share-diluted	8.99	8.81	8.95

Quarterly contributions were as follows:

2002 Quarterly Information *($ millions, except per share amounts)*	Q4	Q3	Q2	Q1*
Revenues, net of royalties and production taxes	$ 3,392	$ 2,882	$ 2,676	$ 1,061
Net earnings from continuing operations	416	184	494	131
– per common share-diluted	0.86	0.38	1.05	0.51
Net earnings	429	204	458	133
– per common share-diluted	0.88	0.42	0.97	0.51
Cash flow from continuing operations	1,449	1,027	916	387
– per common share-diluted	2.99	2.13	1.95	1.48
Cash flow	1,472	1,022	938	389
– per common share-diluted	3.03	2.12	2.00	1.49

* Q1 2002 results exclude the results of AEC.

ACQUISITIONS AND DIVESTITURES

Acquisitions

On May 31, 2002, the Company expanded its production, reserves, land holdings, and gathering system assets in the U.S. Rocky Mountain region with the purchase of assets by one of its U.S. subsidiaries 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 August 1, 2002, the Company announced that one of its U.S. subsidiaries had further strengthened its position in the U.S. Rocky Mountain region through the purchase of producing and non-producing assets in the Jonah field, in southwest Wyoming, for approximately $550 million. The acquisition included developed and undeveloped reserves and increased EnCana's interest in the Jonah field production from approximately 50 percent to approximately 75 percent.

On January 31, 2003, the Company expanded its production and landholdings in Ecuador with the purchase of assets for approximately US$137 million, including working capital and subject to normal post-closing adjustments and expenses. This acquisition included interests in developed and undeveloped reserves in three blocks adjacent to Block 15, where the Company has a non-operated working interest.

Divestitures

In December 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $93 million with a gain on disposal of $51 million.

On February 3, 2003, the Company announced that it had reached an agreement to sell a 10 percent interest in the Syncrude project for approximately $1,070 million. The Company also granted the purchaser an option to purchase, on similar terms prior to the end of 2003, its remaining 3.75 percent share and an overriding royalty. If exercised, it is anticipated that the option would generate additional proceeds of approximately $417 million. With the sale of its Syncrude interest, the Company intends to focus its oilsands strategy on developing its high quality resources, recovered through steam-assisted gravity drainage ("SAGD"), on 100 percent owned and operated lands at Foster Creek and Christina Lake. The sale of EnCana's interest in Syncrude is subject to regulatory approvals and the completion of other closing conditions by the parties. The transaction is expected to close on or about February 28, 2003.

Discontinued Operations

Merchant Energy

On April 24, 2002, the Company adopted formal plans to exit from its Houston-based merchant energy operation, which was previously included in the Midstream & Marketing segment. The wind-down of this operation has been substantially completed. At December 31, 2002, an after-tax loss of $49 million has been recorded, which includes the costs associated with completing 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 in 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 has also received a subpoena from the U.S. Commodity Futures Trading Commission requiring the Company to produce documents and other information in connection with that agency's investigation relating to, among other things, inaccurate reporting of natural gas and power trading information by employees of a number of energy trading firms, including former employees of the Company's Houston-based merchant energy operation, to energy industry publications that compile and report index prices. The Company is cooperating fully in responding to all of these requests. While no assurance can be provided, based on information currently available to the Company, the Company believes that none of these inquiries by U.S. governmental agencies is likely to result in a material adverse effect upon the Company.

Midstream – Pipelines

On July 9, 2002, the Company announced plans to dispose of its indirect 100 percent interest in the Express Pipeline System and its indirect 70 percent interest in the Cold Lake Pipeline System. On January 2, 2003, the Company announced that it had closed the sale of its interest in the Cold Lake Pipeline System for approximately $425 million, subject to post-closing adjustments. On January 9, 2003, the Company announced that it had closed the sale of its indirect 100 percent interest in the Express Pipeline System. The proceeds of this sale were approximately $1,175 million, including the assumption of approximately $599 million in debt, and are subject to post-closing adjustments. These two sales were part of EnCana's strategic realignment to focus on its highest growth, highest return core assets. It is anticipated that the proceeds will be used for general corporate purposes, including debt reduction, prior to being re-deployed into other strategic initiatives.

The merchant energy and midstream-pipeline operations described above have both been accounted for as discontinued operations as described in Note 5 to the Consolidated Financial Statements.

BUSINESS ENVIRONMENT

(average for the year unless otherwise noted)	2002	2001	2000
AECO Price *($ per thousand cubic feet)*	$ 4.07	$ 6.30	$ 5.02
NYMEX Price *(US$ per million British thermal units)*	3.22	4.27	3.89
WTI *(US$ per barrel)*	26.15	25.95	30.26
WTI/Bow River Differential *(US$ per barrel)*	5.93	9.87	7.12
WTI/Oriente Differential (Ecuador) *(US$ per barrel)*	4.16	7.02	5.96
U.S./Canadian Dollar Exchange Rate *(US$)*	0.637	0.646	0.673

Natural gas prices in 2002 showed significant decline from strong 2001 average prices. The average AECO index price for 2002 was $4.07 per thousand cubic feet, down 35 percent from an average price of $6.30 per thousand cubic feet in 2001 and down 19 percent from $5.02 per thousand cubic feet in 2000. Although natural gas prices showed improvement in late 2002, for most of the year prices were negatively affected by high levels of natural gas in storage resulting from decreased demand. In 2002, the AECO index price continued to be strong relative to NYMEX prices. In 2002, the NYMEX to AECO basis differential increased to US$0.66 per million British thermal unit from US$0.29 per million British thermal unit in 2001. This was mainly caused by high levels of gas in storage and the decontracting of firm service forcing additional Alberta supply to flow on higher cost interruptible transport leaving the western basin.

World crude oil prices improved somewhat in 2002 compared with 2001 prices. The benchmark West Texas Intermediate ("WTI") crude oil price averaged US$26.15 per barrel in 2002, compared with US$25.95 per barrel in 2001 and US$30.26 per barrel in 2000. Oil prices at the beginning of 2002 were low, with the WTI crude oil price averaging US$21.63 per barrel in the first quarter, but continued to climb throughout the year ending with an average price of US$28.23 per barrel in the fourth quarter. Oil prices gained strength during the year due in part to maintenance of production quotas by OPEC, uncertainty surrounding tensions in the Middle East and disruptions in the supply of oil from Venezuela.

In 2002, the differential between heavy and light crude oil prices benefited from improvements in the supply/demand balance for heavy oil. The WTI/Bow River differential averaged US$5.93 per barrel, compared with US$9.87 per barrel in 2001 and US$7.12 per barrel in 2000.

The average WTI/Oriente differential in 2002 was US$4.16 per barrel compared with US$7.02 per barrel and US$5.96 per barrel in 2001 and 2000, respectively. Oriente crude differentials narrowed in 2002 due to restricted heavy crude availability and a related decrease in the light/heavy product differential in the U.S. Gulf Coast. Restricted heavy crude availability arose from lower Iraq crude volumes, sporadic hurricanes on the U.S. Gulf Coast and, towards the end of the year, the sudden withdrawal of Venezuelan supply.

The U.S./Canadian dollar exchange rate experienced a fluctuating trend in 2002 reflecting economic and political uncertainties throughout the year. The Canadian dollar averaged US$0.637 in 2002, down from US$0.646 in 2001 and US$0.673 in 2000. At year-end the U.S./Canadian dollar exchange rate was US$0.633, compared with year-end rates of US$0.628 and US$0.667 in 2001 and 2000, respectively.

RESULTS OF OPERATIONS

Upstream – Onshore North America and Offshore & International

Financial Results *($ millions)*	2002				2001				2000			
	Produced Gas & NGLs	Conventional Crude Oil	Syncrude	Total	Produced Gas & NGLs	Conventional Crude Oil	Syncrude	Total	Produced Gas & NGLs	Conventional Crude Oil	Syncrude	Total
Revenues												
Gross revenue	$ 4,342	$ 2,142	$ 369	$ 6,853	$ 2,680	$ 1,060	$ –	$ 3,740	$ 1,886	$ 1,340	$ –	$ 3,226
Royalties and production taxes	615	370	4	989	180	123	–	303	114	145	–	259
Revenues, net of royalties and production taxes	3,727	1,772	365	5,864	2,500	937	–	3,437	1,772	1,195	–	2,967
Expenses												
Transportation and selling	336	98	4	438	121	35	–	156	98	34	–	132
Operating	471	452	164	1,087	192	254	–	446	133	235	–	368
Depreciation, depletion and amortization				2,036				799				725
Upstream income	$ 2,920	$ 1,222	$ 197	$ 2,303	$ 2,187	$ 648	$ –	$ 2,036	$ 1,541	$ 926	$ –	$ 1,742

Sales Volumes	2002	2001	2000
Produced Gas *(million cubic feet per day)*	2,354	1,053	949
Crude Oil *(barrels per day)*	183,015	100,803	109,355
NGLs *(barrels per day)*	24,045	13,636	12,665
Syncrude *(barrels per day)*	23,777	–	–
Total *(barrel of oil equivalent per day)**	623,170	289,939	280,187

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

Revenues Variances *($ millions)*	2002 compared to 2001				2001 compared to 2000		
	Price	Volume	Merger* Volume	Total	Price	Volume	Total
Produced gas and NGLs	$ (579)	$ 487	$ 1,754	$ 1,662	$ 586	$ 208	$ 794
Conventional crude oil	137	80	865	1,082	(166)	(114)	(280)
Syncrude	–	–	369	369	–	–	–
Total gross revenue	$ (442)	$ 567	$ 2,988	$ 3,113	$ 420	$ 94	$ 514

* Represents estimate of revenue resulting from the addition of volumes related to existing AEC properties as at the date of the merger.

Consolidated Upstream Results

The Company reports its segmented financial results showing revenues prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry. Upstream gross revenue for the year rose 83 percent, or $3,113 million, to $6,853 million compared with 2001 and was $3,627 million higher than 2000 gross revenue. Included in 2002 gross revenue is $168 million relating to the fair value of AEC's forward gas sales contracts recorded as part of the business combination. This amount has been excluded for the purposes of discussing realized prices.

Excluding the impact of hedging, royalties and production taxes were 15 percent of revenues in 2002 compared with nine percent and eight percent in 2001 and 2000, respectively. The increased rate reflects the addition of AEC's production base, which is predominantly in areas subject to crown royalties, thereby decreasing the Company's relative proportion of production attributable to fee land where only mineral taxes are payable.

2002 transportation and selling costs were $438 million compared with $156 million in 2001 and $132 million in 2000. Higher sales volumes year over year were the primary factor contributing to the increase in these costs. For the purpose of the revenue discussions below, these costs have been netted against revenues in calculating the per unit realized prices for each commodity.

Upstream operating expenses, excluding Syncrude operations, totalled $923 million in the year, an increase of $477 million over 2001. Additional production resulting from the merger with AEC was the primary factor contributing to the increase in costs. On a per unit basis, conventional operating expenses, excluding cost recoveries, were $4.06 per barrel of oil equivalent in 2002 compared with $4.21 per barrel of oil equivalent in 2001. The improvement in unit operating expenses primarily reflects the impact of lower costs associated with conventional crude oil production.

2001 upstream operating expenses of $446 million were $78 million higher than 2000 operating expenses of $368 million. The higher 2001 costs reflected higher downhole, maintenance, electricity and fuel costs.

Depreciation, depletion and amortization ("DD&A") expense was $2,036 million for the year compared with $799 million in 2001 and $725 million in 2000. On a barrel of oil equivalent basis, DD&A charges were up 19 percent from 2001 to $8.95 per barrel. At $7.55 per barrel in 2001, DD&A charges were six percent higher than 2000 unit costs of $7.09 per barrel. The higher costs in 2002 primarily reflected the added charges associated with the addition of the AEC assets, which were recorded at their fair value as part of the allocation of the purchase price as outlined in Note 3 to the Consolidated Financial Statements.

Produced Gas and NGLs

Per-Unit Results – Produced Gas and NGLs

	Produced Gas – Canada			Produced Gas – U.S.			NGLs		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
	($ per thousand cubic feet)			*($ per thousand cubic feet)*			*($ per barrel)*		
Price, net of transportation and selling	$ 4.18	$ 6.53	$ 4.76	$ 4.25	$ 3.85	$ 5.43	$ 30.70	$ 31.20	$ 33.31
Royalties and production taxes	0.57	0.38	0.29	1.16	1.72	2.34	4.49	1.22	1.77
Operating expenses	0.55	0.47	0.36	0.34	0.73	0.51	–	–	–
Netback including hedge	3.06	5.68	4.11	2.75	1.40	2.58	26.21	29.98	31.54
Hedge	0.07	0.58	(0.13)	0.36	–	–	–	–	–
Netback excluding hedge	$ 2.99	$ 5.10	$ 4.24	$ 2.39	$ 1.40	$ 2.58	$ 26.21	$ 29.98	$ 31.54

In 2002, sales of produced gas and natural gas liquids ("NGLs") contributed $4,342 million to revenues, an increase of $1,662 million, or 62 percent, over 2001. The increase in 2002 gross revenue was largely attributable to increased sales volumes resulting from the merger with AEC in combination with the Company's expansion in the U.S. Rocky Mountain region, and drilling successes such as those at Jonah, Mamm Creek, Greater Sierra and Ferrier.

Produced gas sales volumes increased 1,301 million cubic feet per day over 2001, averaging 2,354 million cubic feet per day for the year. NGL sales also improved, to 24,045 barrels per day compared with sales volumes of 13,636 barrels per day in 2001. The impact of the Company's growth in natural gas sales volumes was partly offset by weaker regional natural gas prices. Realized natural gas sales prices in Canada averaged $4.18 per thousand cubic feet in 2002, a decrease of 36 percent from an average of $6.53 per thousand cubic feet in 2001. In contrast, the realized price for natural gas in the U.S. increased by approximately 10 percent over last year to $4.25 per thousand cubic feet.

Gross revenue from the sales of produced gas and NGLs was $2,680 million in 2001, an improvement over revenue of $1,886 million in 2000. Stronger 2001 Canadian market prices, the increase in production stemming from the acquisition of the Montana Power Assets in late 2000 and a successful drilling program contributed to the growth in 2001 revenue.

2002 gross natural gas revenue was $103 million higher as the result of a net gain from currency and commodity hedging activities. This compared to a gain of $208 million in 2001 and a loss of $43 million in 2000.

In 2002, produced gas operating expenses, net of operating recoveries, were $0.55 per thousand cubic feet for Canadian production and $0.34 per thousand cubic feet for U.S. production. This compared with $0.47 per thousand cubic feet for Canadian production and $0.73 per thousand cubic feet for U.S. production in 2001. Higher operating costs for British Columbia production, plant turnarounds and increased processing fees related to non-operated production were the primary factors contributing to the increase in costs for Canadian production. In 2002, unit operating costs related to U.S. production benefited from the addition of lower operating cost properties at Jonah and Mamm Creek acquired as part of the merger with AEC.

Unit operating expenses in 2001 were higher than 2000 unit costs for both Canadian and U.S. production. Factors underlying the rise in unit costs were increased downhole, maintenance, lease and electricity costs. The increased maintenance expense in 2001 partially reflected a compressor maintenance program in the first half of 2001 that was designed to improve service factors for natural gas facilities.

Conventional Crude Oil

Per-Unit Results – Conventional Oil

	Onshore North America			Ecuador			United Kingdom		
($ per barrel)	2002	2001	2000	2002	2001	2000	2002	2001	2000
Price, net of transportation and selling	$ 29.14	$ 26.76	$ 32.95	$ 33.43	$ –	$ –	$ 36.14	$ 36.21	$ 28.47
Royalties and production taxes	3.95	3.73	4.05	11.82	–	–	–	–	–
Operating expenses	6.48	7.23	5.94	5.43	–	–	5.15	4.18	5.29
Netback including hedge	18.71	15.80	22.96	16.18	–	–	30.99	32.03	23.18
Hedge	(1.05)	0.86	(1.50)	(0.01)	–	–	(0.09)	0.76	(10.69)
Netback excluding hedge	$ 19.76	$ 14.94	$ 24.46	$ 16.19	$ –	$ –	$ 31.08	$ 31.27	$ 33.87

In 2002, gross revenue from the sale of conventional crude oil was $2,142 million, an increase of $1,082 million, or 102 percent, over 2001. The improvement in gross revenue was primarily attributable to the volumes added from the merger of the Company with AEC combined with strengthened world oil prices and narrower North American heavy crude oil differentials.

Onshore North America conventional crude oil sales volumes averaged 131,761 barrels per day in 2002 compared with 89,982 barrels per day in 2001. The increase in sales volumes was the result of the inclusion of merger related volumes, continued development at Suffield, commencement of commercial production at Christina Lake and the ramping up of production at Foster Creek. The Company's 2002 realized price from Onshore North America crude was $29.14 per barrel, an improvement over an average price of $26.76 per barrel in 2001.

Unit operating costs for Onshore North America conventional crude oil were $6.48 per barrel, an improvement over costs of $7.23 per barrel in 2001. The improvement in operating expenses for the year was the result of lower per unit costs related to the added AEC production and lower electricity costs.

In 2001, unit operating costs increased to $7.23 per barrel compared with costs of $5.94 per barrel in 2000. The increase in crude oil operating expenses reflected higher downhole, maintenance, electricity and fuel costs.

Conventional oil sales from Offshore & International averaged 51,254 barrels per day, which compared with 10,821 barrels per day in 2001. The increase in sales volumes reflects the addition of 41,521 barrels per day of Ecuador oil volumes, which helped to offset a reduction in U.K. sales volumes. Realized crude oil prices on the Company's Offshore & International sales averaged $33.43 per barrel for Ecuador oil and $36.14 per barrel for U.K. oil. Comparatively, 2001 U.K. realized crude oil prices averaged $36.21 per barrel.

Offshore & International conventional crude oil unit operating costs were $5.43 per barrel for Ecuador oil and $5.15 per barrel for U.K. production in 2002. Costs related to U.K. crude oil production increased over 2001 costs of $4.18 per barrel due primarily to higher work-over, maintenance and insurance costs.

2001 gross revenue from sales of conventional crude oil declined 21 percent from 2000, to $1,060 million. Softer 2001 crude oil prices and a widening of the heavy crude oil differential contributed to the decline. In addition to weaker prices, 2001 conventional crude oil volume levels were lower as a result of general declines experienced in maturing crude oil pools and the Company's sale of non-core properties, such as the heavy crude oil operations at Pelican Lake in February 2001.

Conventional crude oil gross revenue in 2002 was reduced by a loss of approximately $51 million from commodity and currency hedging, which compared to a $31 million gain in 2001 and a loss of $100 million in 2000.

Syncrude

As a result of the merger, EnCana added Syncrude oil production to its Onshore North America upstream operating results. Syncrude sales added $369 million to upstream revenues in 2002 with sales volumes averaging 23,777 barrels per day. 2002 sales volumes were impacted by lower volume levels in the second quarter due to a longer than anticipated period for the coker turnaround. Volumes returned to expected levels of 36,039 barrels per day and 34,261 barrels per day in the third and fourth quarters, respectively. In 2002, Syncrude gross revenue was reduced by approximately $8 million resulting from a loss related to commodity price hedging.

Syncrude operating costs were $164 million in 2002, or $18.80 on a per unit basis. Operating expenses were impacted by high second quarter costs of $30.47 per barrel as a result of the coker turnaround.

As previously discussed, the Company has reached an agreement to sell a 10 percent interest in the Syncrude project and has granted the purchaser an option to purchase the remaining 3.75 percent interest and overriding royalty prior to the end of 2003. The transaction is expected to close on or about February 28, 2003. Further details regarding this sale are included in Note 22 to the Consolidated Financial Statements.

Midstream & Marketing

Financial Results* *($ millions)*	Midstream			Marketing			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues	$ 760	$ 260	$ 311	$ 3,373	$ 1,202	$ 1,090	$ 4,133	$ 1,462	$ 1,401
Expenses									
Transportation and selling	–	–	–	136	16	16	136	16	16
Operating	331	228	229	20	19	23	351	247	252
Purchased product	265	–	–	3,183	1,144	1,019	3,448	1,144	1,019
Depreciation, depletion and amortization							62	20	17
	$ 164	$ 32	$ 82	$ 34	$ 23	$ 32	$ 136	$ 35	$ 97

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

In 2002, revenues from continuing midstream operations were $760 million compared with $260 million in 2001 and $311 million in 2000. The increase in 2002 was largely the result of the addition of the AEC midstream assets, which primarily include gas storage facilities and natural gas processing, to the Company's existing midstream segment. In addition, the NGLs processing business benefited from lower than forecast AECO gas prices lowering the cost of natural gas feedstock, which improved processing margins. Gas storage benefited from the late year volatility in gas prices and the optimization opportunities captured as a result. In 2001, revenues declined from 2000 levels due mainly to planned reductions in production of extracted NGLs.

Marketing Financial Results* **On a product basis** *($ millions)*	Gas			Crude Oil & NGLs			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues	$ 1,456	$ 595	$ 319	$ 1,917	$ 607	$ 771	$ 3,373	$ 1,202	$ 1,090
Expenses									
Transportation and selling	58	1	2	78	15	14	136	16	16
Operating							20	19	23
Purchased product	1,349	567	306	1,834	577	713	3,183	1,144	1,019
	$ 49	$ 27	$ 11	$ 5	$ 15	$ 44	$ 34	$ 23	$ 32

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

Gross revenue from the Company's marketing activities totalled $3,373 million in 2002, an increase over gross revenue of $1,202 million and $1,090 million in 2001 and 2000, respectively. The increase in 2002 largely reflected the addition of volumes related to the merger with AEC. In addition, a marketing arrangement with a third party also contributed to the increase in revenues from crude oil and NGLs. In 2002, this agreement required EnCana to purchase third party Syncrude volumes, approximately 46,108 barrels per day, for resale from February to December. During 2001 and January 2002, this marketing arrangement was on an agency basis, which did not require the Company to take physical title of these volumes. This agreement continues in 2003 but reverts back to an agency agreement from February 2003 forward.

Midstream & Marketing depreciation and amortization expenses were $62 million for the year compared with $20 million in 2001 and $17 million in 2000. The growth in the segment asset base resulting from the addition of AEC's midstream assets was the primary factor contributing to the increase in depreciation and amortization expenses.

Corporate

Administrative expenses for the year totalled $187 million. In comparison, these expenses were $83 million in 2001 and $68 million in 2000. The higher expenses in 2002 included increases in compensation costs, office facilities charges and information technology costs. The increase in these costs was primarily attributable to the increased size of the Company. On a per-unit basis, administrative costs were $0.82 per barrel of oil equivalent in 2002 compared with $0.78 per barrel of oil equivalent in 2001 and $0.66 per barrel of oil equivalent in 2000.

Net interest expense was $419 million, up from $45 million in 2001 and $69 million in 2000. The rise in net interest expense resulted primarily from the additional interest expense associated with debt acquired as a result of the merger, an increase resulting from higher debt levels associated with the U.S. dollar notes issued in the fourth quarter of 2001 and lower 2002 cash levels.

Foreign exchange resulted in a gain of $20 million, which compared with a loss of $20 million in 2001 and a $37 million loss in 2000. 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 practices for operations outside of Canada and determined that such operations were self-sustaining. Previously 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 an increase in net earnings of $2 million for the year ended December 31, 2002.

The provision for income tax was $618 million in 2002, $631 million in 2001 and $633 million in 2000. The decrease included the impact of a $47 million reduction in future income taxes resulting from a reduction in the Alberta corporate tax rate in 2002. The effective tax rate for 2002 was 33 percent. This compares to an effective tax rate of 34 percent in 2001 and 39 percent in 2000. The provision for current income tax decreased significantly in 2002, resulting in a recovery of $49 million compared with an expense of $497 million in 2001 and $163 million in 2000. The decrease reflects lower taxable income in 2002, which results in part from the merger with AEC and the subsequent resulting business reorganization of the Company's business units at the end of 2002 and in early 2003 and the amalgamation with AEC on January 1, 2003. The current income tax decrease was offset by an equivalent increase in future income tax. The future income tax provision in 2002 was $667 million compared to $134 million in 2001 and $470 million in 2000.

On December 12, 2002, the Company announced that it intended to consolidate its corporate structure through a vertical short-form amalgamation with its wholly owned subsidiary AEC. The amalgamation was completed effective January 1, 2003 and did not require any EnCana or AEC public securityholder vote. Upon completion of the amalgamation, EnCana became the successor issuer in respect of AEC's previously issued debt securities and is responsible for all of AEC's contractual obligations.

LIQUIDITY AND CAPITAL RESOURCES

The Company believes that its existing credit facilities and present and expected capital resources, including the proceeds from the sales of its interests in the Express and Cold Lake Pipeline Systems and the sale of a 10 percent interest in Syncrude, will support its capital investment programs and future growth prospects, in addition to enabling the Company to meet all other current and expected financial requirements.

EnCana's cash flow from continuing operations of $3,779 million in 2002 compared with $2,259 million in 2001 and $2,278 million in 2000. The increased cash flow from continuing operations was primarily the result of higher revenues resulting from the Company's growth in sales volumes during the year and a lower cash tax expense.

At December 31, 2002, the Company had working capital of $410 million compared with $33 million at the end of 2001. The increase in working capital was primarily due to the current nature of the Company's discontinued assets at the end of the year and a reduction of $642 million in current income taxes payable compared with 2001. These were partially offset by the addition of $438 million in short-term debt and an increase in accounts payable resulting primarily from an expanded capital program in 2002.

EnCana's net debt at year-end, including preferred securities, increased to $7,568 million from $2,303 million at the end of 2001. This increase was primarily a result of the debt acquired in the merger. Net debt to capitalization, including all preferred securities as debt, was 36 percent, down from 37 percent at December 31, 2001.

At December 31, 2002, the Company had $2,886 million in goodwill recorded on its Consolidated Balance Sheet as a result of the merger with AEC. The amount of goodwill recorded represents the excess of the purchase price over the fair value of net assets acquired in the business combination. Details regarding the accounting for the business combination, including the allocation of the purchase price to assets and liabilities, are described in Note 3 to the Consolidated Financial Statements. The Company assesses goodwill for impairment at least on an annual basis, at which time any identified impairment would be charged to income. At December 31, 2002, there was no impairment related to goodwill.

At December 31, 2002, the Company had $457 million in preferred securities of a subsidiary recorded as a liability on its balance sheet. These preferred securities are unsecured junior subordinated debentures and were recorded as a liability of the Company following the merger with AEC. The Company recognized $20 million, net of tax for distributions on the preferred securities of the subsidiary in 2002. On January 1, 2003, these preferred securities became the direct obligation of EnCana as a result of the amalgamation of the Company with AEC and accordingly will be recorded under the shareholders' equity section of the Consolidated Balance Sheet in future periods. Details regarding these preferred securities of subsidiary are described in Note 15 to the Consolidated Financial Statements.

On October 2, 2002, the Company issued $300 million of unsecured five-year debentures at a coupon rate of 5.30%. Proceeds from the offering were used to repay amounts outstanding under revolving credit and term loan borrowings.

On October 16, 2002 EnCana received approval from the Toronto Stock Exchange ("TSX") to make a Normal Course Issuer Bid. Under the bid, EnCana may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. Purchases under the program must terminate on October 21, 2003 or on such earlier date as the Company may complete its purchases pursuant to the Notice of Intention filed with the TSX. Purchases will be made on the open market through the facilities of the TSX in accordance with its policies. The price to be paid will be the market price at the time of acquisition. As at December 31, 2002, the Company had not yet made any purchases under this program.

In December 2002, the Company completed the early redemption of its subsidiary's US$113 million 6.78% and US$85 million 7.34% unsecured private notes for total consideration, including accrued interest, of approximately US$226 million. The Company also completed the early redemption of its subsidiary's $430 million principal amount, Capital Securities for total consideration, including accrued interest, of approximately $495 million. These early retirements were completed in order to simplify the Company's financial structure and take advantage of lower interest rates. An after-tax charge of approximately $30 million was recorded in relation to these transactions.

In December 2002, the Company completed the refinancing of its general corporate bank credit facilities. Under this refinancing, five separate corporate facilities were consolidated into a single syndicated corporate bank credit facility totalling $4 billion to be used for general corporate purposes.

Capital Expenditures

The Company's consolidated net capital expenditures were $4,281 million in 2002 compared with $1,824 million in 2001 and $2,221 million in 2000. The Company's net investing for 2002 was funded by cash flow of $3,821 million and long-term debt.

Included in net capital expenditures for 2002 was $566 million related to proceeds on disposals of capital assets, compared with proceeds of $47 million in 2001 and $193 million in 2000. These disposals related primarily to property rationalization consistent with the Company's continued focus on maximizing profitability by selling non-core assets. Also included in 2002 net capital expenditures was $93 million related to proceeds on the sale of the Company's investment in EnCana Suffield Gas Pipeline Inc. This compared with $84 million in net corporate dispositions in 2001 and $948 million in corporate acquisitions in 2000. In 2001, net corporate dispositions included proceeds from the sale of an oil and gas property and the acquisition of Causeway, a junior oil and gas producer. Corporate acquisitions in 2000 reflected the Company's purchase of Montana Power and its interest in the Scott and Telford properties in the U.K.

The following table provides a summary of the Company's capital spending, excluding dispositions, on a divisional basis.

Capital Expenditures *($ millions)*	2002	2001	2000
Upstream			
Onshore North America	$ 3,662	$ 1,356	$ 1,071
Offshore & International	1,126	407	266
Total Upstream	4,788	1,763	1,337
Midstream & Marketing	87	165	90
Corporate	65	27	39
Total	$ 4,940	$ 1,955	$ 1,466

Upstream Capital Expenditures

Onshore North America

In 2002, capital expenditures in the Onshore North America division were $3,662 million compared with $1,356 million in 2001 and $1,071 million in 2000. The majority of the division's 2002 capital expenditures were directed towards exploration and development of natural gas properties in the U.S. Rockies, the Greater Sierra area of northeastern

British Columbia, southeastern Alberta and the Alberta Foothills, combined with heavy oil development at Suffield and Pelican Lake, commercial development of the SAGD projects at Foster Creek and Christina Lake and continued expansion at Syncrude. Capital spending in the year included approximately $420 million related to the purchase of Colorado natural gas properties and approximately $550 million related to the acquisition of producing and non-producing properties in southwestern Wyoming. In 2001 and 2000, the majority of capital spending was related to natural gas exploration and development.

Offshore & International

Capital expenditures were $1,126 million in 2002 compared with $407 million in 2001 and $266 million in 2000. The majority of 2002 capital spending was directed towards development of the producing properties in Ecuador, as well as the major exploration and development projects in the Gulf of Mexico, East Coast of Canada and the U.K. central North Sea. The Company was unsuccessful in finding commercial quantities of hydrocarbons in the Kingdom of Bahrain and consequently $28 million was written off as an expense in 2002. In 2001 and 2000, capital spending in the division was focused primarily on exploration and development in the U.K. central North Sea and East Coast of Canada.

Reserves

In addition to its own internal engineering, EnCana retained independent petroleum engineering consultants to evaluate and prepare reports on 100 percent of its oil and gas reserves as of December 31, 2002. The Company has a Reserve Committee comprised entirely of independent directors which reviews its publicly-disclosed reserve estimates and approves the selection, qualification and procedures of the independent engineering consultants.

During 2002, the Company added approximately 1,900 million barrels of oil equivalent, net of sales, sales of reserves in place and revisions, to its proved reserves through the merger with AEC, the acquisition of selected properties and drill bit successes. EnCana's proved reserves as at December 31, 2002, on a constant price basis, before royalties, totalled 2,913 million barrels of oil equivalent. The 2,913 million barrels of oil equivalent was comprised of 8,973 billion cubic feet of natural gas, 983 million barrels of conventional oil and NGLs and 434 million barrels of Syncrude. The following table provides a summary of the proved reserves by country:

Proved Reserves by Country *As at December 31, 2002*	Canada	U.S.	Ecuador	U.K.	Total
Natural Gas *(billions of cubic feet)*	5,783	3,170	–	20	8,973
Conventional Oil and NGLs *(millions of barrels)*	623	50	212	98	983
Syncrude *(millions of barrels)*	434	–	–	–	434
Total barrels of oil equivalent* *(millions of barrels)*	2,022	578	212	101	2,913

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

Midstream & Marketing Capital Expenditures

On October 17, 2002, EnCana announced plans to develop a new natural gas storage facility in southeastern Alberta that is anticipated to store up to 40 billion cubic feet of gas. On completion of the development, the Countess gas storage facility is expected to increase the Company's Western Canada gas storage capacity by approximately 40 percent to more than 135 billion cubic feet. At December 31, 2002, approximately $12 million had been invested. The Company expects that the total completion cost related to this project will be approximately $140 million.

Capital expenditures of $87 million were down from $165 million in 2001 and $90 million in 2000. The 2002 expenditures related primarily to ongoing improvements to midstream facilities, the construction of the Countess storage facility, and expansion of the Wild Goose storage facility. Capital expenditures in 2001 and 2000 were principally due to the construction of two new power generation plants in Alberta.

The construction of the 450,000 barrel per day OCP pipeline in Ecuador is continuing on target for final completion in the third quarter of 2003. It is expected that restricted transportation service, sufficient to meet initial shipper requirements, will be available by the middle of 2003. At December 31, 2002, $27 million had been invested related to the Company's 31.4% equity interest in the pipeline project. The Company estimates that its final investment will be approximately US$160 million.

Corporate Capital Expenditures

Corporate capital expenditures were $65 million in 2002, compared with $27 million in 2001 and $39 million in 2000. In 2002, these expenditures related primarily to spending on business information systems, furniture and office equipment and leasehold improvements. Expenditures in 2001 and 2000 related primarily to spending on business information systems.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has operating leases in place on a variety of moveable field equipment, natural gas storage equipment and aircraft, which require periodic lease payments, recorded as operating costs, and provide for a minimum stipulated return value. If the leases are not renewed and the market value of the equipment is less than the return value, the Company could be required to make whole any value deficiency at the end of the lease. The minimum stipulated return values amount to $144 million in 2005, $115 million in 2006 and $46 million in 2007 and beyond. At the inception of the leases the value of the equipment under lease was $370 million. The acquisitions of the equipment and aircraft were financed by variable interest entities that were sponsored by various financial institutions. These variable interest entities are not consolidated into the Company's financial statements. The Company has accounted for these arrangements as operating leases in accordance with Canadian GAAP.

The Financial Accounting Standards Board ("FASB") in the United States has issued FASB Interpretation No.46 ("FIN 46") "Consolidation of Variable Interest Entities" effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that the primary beneficiary consolidate certain variable interest entities. These operating leases will be consolidated under the new standard as written. Further details regarding these operating leases are included in Note 21 to the Consolidated Financial Statements.

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Company has entered into various commitments primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements. The following table summarizes the Company's contractual obligations at December 31, 2002:

	Maturity				
Contractual Obligations* *($ millions)*	Less than 1 year	1 – 3 years	4 – 5 years	In Excess of 5 years	Total
Long Term Debt	$ 212	$ 496	$ 615	$ 4,147	$ 5,470
Preferred Securities of Subsidiary	–	–	–	457	457
Preferred Securities	–	–	–	126	126
Operating Leases	71	277	215	283	846
Transportation Agreements	461	889	782	2,859	4,991
Capital Commitments	791	379	44	61	1,275
Product Purchase Agreements	32	2	47	307	388
Other Long Term Obligations	8	55	33	45	141
Total Contractual Obligations	$ 1,575	$ 2,098	$ 1,736	$ 8,285	$13,694

* This table outlines the principal amounts of the noted obligations.

In addition to the long-term debt payments outlined above, at December 31, 2002, the Company had $2,047 million outstanding related to commercial paper borrowings and term loan borrowings that are supported by revolving credit facilities. The Company intends and has the ability to extend the term of this debt on an ongoing basis. Further details regarding the Company's long-term debt are described in Note 13 to the Consolidated Financial Statements.

Additional disclosure regarding the other contractual obligations outlined above is included in Note 21 to the Consolidated Financial Statements.

As of December 31, 2002, EnCana had entered into long-term, fixed price, physical contracts with a current delivery of approximately 68 million cubic feet per day with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 224 billion cubic feet at a weighted average price of $4.79 per thousand cubic feet. At December 31, 2002, these transactions had an unrealized loss of $220 million.

ACCOUNTING POLICIES

Critical Accounting Policies

Management is often required to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining EnCana's financial results.

Full Cost Accounting

EnCana follows the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and gas industry to account for conventional oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proven reserves (see reserves discussion below), before royalties. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depreciation, depletion and amortization ("DD&A"). A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss.

Oil and Gas Reserves

Commencing in 2002, EnCana's proved oil and gas reserves are 100 percent evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

Asset Impairment

Under full cost accounting, a ceiling test is performed, on a quarterly basis, to ensure that unamortized capitalized costs in each cost centre do not exceed the sum of estimated undiscounted, unescalated future net revenues from proved reserves, plus unimpaired unproved property costs, less future development costs, related production, dismantlement and site restoration, interest, administrative costs and applicable taxes. The ceiling test calculation utilizes and holds constant the sales prices and costs in effect at the end of the period. As a result, the calculation of future net revenues from estimated proved reserves are not necessarily reflective of the Company's estimate of future prices or costs and are therefore not necessarily indicative of the true fair value of the reserves. As discussed above, an impairment loss is recognized when the estimated undiscounted future cash flows are less than the net book value of the related capitalized costs.

Future Dismantlement and Site Restoration

The Company provides for estimated future dismantlement and site restoration costs of natural gas and crude oil assets using the unit-of-production method. The estimation of this future liability is inherently difficult and is based on estimates of future costs to abandon and restore a well site. Factors that influence these cost estimates include such things as the number of wells drilled, well depth and area specific environmental legislation. These estimates are revisited on a yearly basis and impact the DD&A rates used by the Company. An upward revision in these future costs could result in a higher DD&A expense being charged to earnings.

Stock-Based Compensation

The Company has a stock-based compensation plan that allows employees and directors to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options are issued. Options granted under the plan are generally fully exercisable after three years and expire five years after the grant date. Generally accepted accounting principles provide the Company with the choice to record a compensation expense in the financial statements for granted share options. EnCana has chosen not to record compensation expense for share options granted to employees and directors. If the fair-value method had been used, approximately $80 million in compensation expense would have been charged against the Company's net earnings. Further details regarding the Company's stock-based compensation plan are included in Note 17 of the Consolidated Financial Statements.

Changes in Accounting Principles

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. Specifically, the Company is now required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item.

RISK MANAGEMENT

EnCana's results are impacted by external market risks associated with fluctuations in commodity prices, foreign exchange rates and interest rates in addition to credit, operational and safety and environmental risks. The use of derivative instruments is governed under formal policies approved by senior management, and is subject to limits established by the Board of Directors.

The Company manages exposure to market risks 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 and enhancing the probability of achieving corporate performance targets.

The following table summarizes the unrecognized gains/(losses) on the Company's risk management activities discussed below.

	Contract Maturity			
($ millions)	2003	2004	2005 and beyond	Total
Natural Gas	$ 128	$ 95	$ 79	$ 302
Crude Oil	(99)	(23)	–	(122)
Gas Storage	(43)	–	–	(43)
Natural Gas Liquids	(3)	–	–	(3)
Power	(2)	–	(1)	(3)
Foreign Currency	(72)	(18)	–	(90)
Interest Rates	26	21	15	62
Total	$ (65)	$ 75	$ 93	$ 103

Commodity Prices

As a means of managing commodity price volatility, the Company has entered into various financial instrument agreements and physical contracts.

Natural Gas

At December 31, 2002, the total unrecognized gain related to all significant natural gas risk management contracts was $302 million, the details of which are outlined below.

Produced Gas

At December 31, 2002, all significant contracts related to produced gas had a total unrecognized gain of $270 million, the details of which are outlined below.

- Approximately 244 million cubic feet per day of natural gas has been sold forward under derivative contracts and 9 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of $5.89 per thousand cubic feet. These contracts had an unrecognized loss of $38 million at December 31, 2002.
- Approximately 118 million cubic feet per day of natural gas has been sold forward under derivative contracts and 10 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of US$3.52 per million British Thermal Unit. These contracts had an unrecognized loss of $32 million at December 31, 2002.
- Approximately 287 million cubic feet of natural gas has been sold forward under derivative contracts at an average NYMEX related price of US$4.10 per million British Thermal Unit for 2003. These contracts had an unrecognized loss of $78 million at December 31, 2002.
- Approximately 37 million cubic feet per day of natural gas has been purchased at an average price of $3.24 per thousand cubic feet offsetting the Company's transportation capacity on the Alliance pipeline for 2003. These contracts had an unrecognized gain of $41 million at December 31, 2002.
- Approximately 42 million cubic feet per day of natural gas has been sold forward under derivative contracts at an average price of US$3.96 per million British Thermal Unit offsetting the Company's transportation capacity on the Alliance pipeline through October 2003. These contracts had an unrecognized loss of $14 million at December 31, 2002.
- Approximately 181 million cubic feet per day of natural gas has been sold forward under derivative contracts through 2007 at an average NYMEX less AECO differential of US$0.49 per million British Thermal Unit. These contracts had an unrecognized gain of $22 million at December 31, 2002.
- Approximately 167 million cubic feet per day of natural gas has been sold forward under derivative contracts and 218 million cubic feet per day sold forward under physical contracts for the period January 2003 through 2007 at an average NYMEX less Rockies differential of US$0.48 per million British Thermal Unit. These contracts had an unrecognized gain of $354 million at December 31, 2002.

- Approximately 50 million cubic feet per day of natural gas was sold forward through 2007 at an average NYMEX less Rockies differential of US$0.38 per million British Thermal Unit in conjunction with a NYMEX costless collar with a price floor of US$2.46 per million British Thermal Unit and a ceiling price of US$4.90 per million British Thermal Unit. These contracts had an unrecognized gain of $9 million at December 31, 2002.
- Approximately 15 million cubic feet per day of natural gas for 2003 has been purchased for fuel use at an average price of $5.15 per thousand cubic feet. These contracts had an unrecognized gain of $6 million at December 31, 2002.

As at January 31, 2003, the Company's Risk Management contracts related to produced gas had an unrecognized gain of $154 million and are outlined below.

- Approximately 504 million cubic feet per day of natural gas has been sold forward under derivative contracts and 9 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of $6.28 per thousand cubic feet. In addition, approximately 100 million cubic feet per day has been sold forward under derivative contracts for 2004 at an AECO equivalent of $6.00 per thousand cubic feet.
- Approximately 190 million cubic feet per day of natural gas has been sold forward under derivative contracts and 19 million cubic feet per day sold forward under physical contracts for 2003 at an average AECO equivalent of US$3.57 per million British Thermal Unit.
- Approximately 266 million cubic feet of natural gas per day has been sold forward under derivative contracts at an average NYMEX related price of US$4.20 per million British Thermal Unit for 2003. In addition, 50 million cubic feet per day was sold forward under derivative contracts for 2004 at an average NYMEX equivalent of US$4.41 per million British Thermal Unit.
- Approximately 37 million cubic feet per day of natural gas has been purchased at an average price of $3.24 per thousand cubic feet, offsetting the Company's transportation capacity on the Alliance pipeline for 2003.
- Approximately 42 million cubic feet per day of natural gas has been sold forward under derivative contracts at an average price of US$3.96 per million British Thermal Unit, offsetting the Company's transportation capacity on the Alliance pipeline for 2003.
- Approximately 181 million cubic feet per day of natural gas has been sold forward under derivative contracts for the period January 2003 to December 2007 at an average NYMEX less AECO differential of US$0.49 per million British Thermal Unit.
- Approximately 167 million cubic feet per day of natural gas has been sold forward under derivative contracts and 218 million cubic feet per day sold forward under physical contracts for the period January 2003 to December 2007 at an average NYMEX less Rockies differential of US$0.48 per million British Thermal Unit.
- Approximately 50 million cubic feet per day of natural gas has been sold forward for the period January 2003 to December 2007 at an average NYMEX less Rockies differential of US$0.38 per million British Thermal Unit, in conjunction with a NYMEX costless collar with a price floor of US$2.46 per million British Thermal Unit and a ceiling price of US$4.90 per million British Thermal Unit.
- Approximately 15 million cubic feet per day of natural gas has been purchased for fuel use at an average price of $5.15 per thousand cubic feet for 2003.

Purchased Gas

As part of the optimization of Midstream & Marketing assets, the Company has entered into contracts to purchase and sell physical volumes of natural gas. The combination of these purchase and sales transactions creates a closed position. On a combined basis these contracts had an unrecognized gain of $32 million at December 31, 2002.

Crude Oil

At December 31, 2002, all significant contracts related to crude oil had a total unrecognized loss of $122 million, the details of which are outlined below.

Produced Crude Oil

- Approximately 85,000 barrels per day in fixed price swaps with an average price of US$25.28 per barrel had been entered into for 2003. The unrecognized loss at December 31, 2002, was $81 million.
- Approximately 40,000 barrels per day in costless collars with a price floor of US$21.95 per barrel and a price cap of US$29.00 per barrel had been entered into for 2003. The unrecognized loss at December 31, 2002, was $16 million.

- Approximately 62,500 barrels per day in fixed price swaps with an average price of US$23.13 per barrel had been entered into for 2004. The unrecognized loss at December 31, 2002, was $10 million.
- Approximately 62,500 barrels per day in costless collars with a price floor of US$20.00 per barrel and a price cap of US$25.69 per barrel had been entered into for 2004. At December 31, 2002, the unrecognized loss related to these contracts was $13 million.

As at January 31, 2003, the unrecognized loss on these contracts was $366 million.

Purchased Crude Oil

- As part of its crude oil marketing activities, the Company managed the risk around crude oil inventory and third party margins through the use of futures and options. As at December 31, 2002, the unrecognized loss on these contracts was $2 million. This loss was fully offset by unrealized gains on physical contracts and inventory.

Gas Storage Optimization

Various financial instruments have been entered into for the next 13-month period to manage price volatility relating to the gas storage optimization program, including futures, fixed-for-floating swaps and basis swaps. At December 31, 2002, these instruments, on a combined basis, had a net unrecognized loss of $43 million, which was more than offset by unrealized gains on physical inventory in storage.

Natural Gas Liquids

- Approximately 315,000 barrels of natural gas liquids in inventory had been sold forward at an average price of US$0.47 per U.S. gallon. The unrecognized loss on these contracts at December 31, 2002, was $1 million.
- At December 31, 2002, the Company had sold forward approximately 562,000 barrels of natural gas liquids at fixed prices ranging from US$0.33 per U.S. gallon to US$0.625 per U.S. gallon. The Company had forward purchased approximately 154,000 barrels of natural gas liquids at fixed prices ranging from US$0.44 per U.S. gallon to US$0.54 per U.S. gallon. In addition, call options with strike prices ranging from US$0.36 per U.S. gallon to US$0.50 per U.S. gallon and swap contracts that fixed prices at US$0.4075 per U.S. gallon had also been entered into. The total loss on these risk management activities at December 31, 2002, was $4 million, of which approximately $2 million was recognized in the 2002 financial results.

Power Purchase Arrangements

The Company acquired two electricity contracts in the merger with AEC that expire in 2003 and 2005. These contracts were entered into as part of a cost management strategy. At December 31, 2002, these contracts had an unrecognized loss of $3 million.

Foreign Currency

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$460 million at an average exchange rate of US$0.716 for the period to June 2004. The unrecognized loss with respect to these contracts was $90 million at December 31, 2002.

Interest Rates

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 $62 million at December 31, 2002.

Credit Risk

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 counterparty and no significant bad debts have been incurred or provided for at December 31, 2002.

Operational Risk

Operational risks are managed through a comprehensive insurance program designed to protect the Company from significant losses arising from the risk exposures.

Safety and Environment

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. The Corporate Responsibility, Environment, Health & Safety Committee of EnCana's Board of Directors approves environmental policy and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as an inspection and audit program are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment.

OUTLOOK

During 2003, EnCana will continue to focus on growing its natural gas production and storage capacity in North America and oil production in Ecuador to deliver anticipated strong near term growth while building on the U.K. central North Sea and the Gulf of Mexico oil growth platforms for expected medium and longer term value creation. The Company will also continue its efforts to expand on its medium and long-term growth prospects by searching for new growth platforms through new ventures exploration.

The Company's 2003 forecast for produced gas sales is between 3.0 and 3.1 billion cubic feet per day, an increase of approximately 30 percent (11 percent on a pro forma basis) over 2002 levels. Sales volumes for conventional oil and natural gas liquids are forecast to be between 240,000 and 280,000 barrels per day, reflecting an anticipated increase of approximately 26 percent (12 percent on a pro forma basis) over 2002.

The Company expects average natural gas prices in 2003 to improve over 2002 levels. High levels of natural gas in storage resulting from decreased demand negatively impacted natural gas prices in 2002. Prices improved towards the end of 2002, primarily reflecting the impact of declining supply. It is anticipated that improvements in the balance between supply and demand will result in stronger average natural gas prices in 2003.

Volatility in crude oil prices is expected to continue in 2003 as a result of market uncertainties over tensions in the Middle East, political issues in Venezuela, OPEC compliance with production quotas and the overall health of the U.S. economy.

2003 capital investment in core programs is anticipated to be approximately $5 billion before acquisitions and dispositions. The Company expects that it will be able to fund its capital program largely from cash flow, in addition to proceeds received on the disposition of non-core assets. The following table provides details of the anticipated capital expenditures on a divisional basis.

2003 Capital Investment *($ millions)*	Exploration	Development	Total
Upstream Conventional			
Onshore North America	$ 350	$ 3,150	$ 3,500
Offshore & International Operations	9	491	500
Offshore & New Ventures Exploration	420	80	500
Total Upstream Conventional	779	3,721	4,500
Midstream & Marketing			500
Total			$ 5,000

EnCana's results are affected by external market factors, such as fluctuations in the prices of crude oil and natural gas as well as movements in foreign exchange rates. The following table provides an estimate of the sensitivity of the Company's 2003 net earnings and cash flow to changes in commodity prices and the U.S./Canadian dollar exchange rate.

Sensitivity of 2003 Net Earnings and Cash Flow *($ millions)*	Net Earnings	Cash Flow
US$0.01 decrease in the value of the Canadian dollar	$ (20)	$ 70
US$1.00 per barrel increase in the price of WTI	40	60
US$0.25 per million British thermal units increase in the NYMEX gas price	135	200

This estimate is based on management's assumptions used for 2003 planning purposes, as discussed in this section, assumes that Syncrude has been sold and includes the impact of all hedging contracts in effect at January 31, 2003.

February 7, 2003

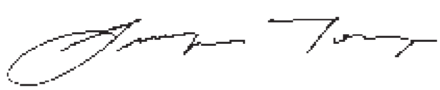
MANAGEMENT REPORT

The accompanying Consolidated Financial Statements of EnCana Corporation are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgements. Financial information contained throughout the annual report is consistent with these Consolidated Financial Statements.

The policy of the Company is to maintain the highest standard of ethics in all its activities and it has a written ethics and integrity policy. The Company has developed and maintains an extensive system of internal controls that provides reasonable assurance that all transactions are accurately recorded, that the Consolidated Financial Statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded. The Company's Internal Audit department reviews and evaluates the adequacy of and compliance with the Company's internal controls.

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

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit the Consolidated Financial Statements and provide an independent opinion.



President &
Chief Executive Officer

Executive Vice-President &
Chief Financial Officer

February 7, 2003

AUDITORS' REPORT

TO THE SHAREHOLDERS OF ENCANA CORPORATION

We have audited the consolidated balance sheets of EnCana Corporation as at December 31, 2002 and December 31, 2001 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three-year period ended December 31, 2002. These financial statements are the responsibility of the Company's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and December 31, 2001 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2002, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
Canada

February 7, 2003

COMMENTS BY AUDITOR FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the change described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 7, 2003 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta
Canada

February 7, 2003

CONSOLIDATED STATEMENT OF EARNINGS

For the years ended December 31 ($ millions, except per share amounts)		2002	2001	2000
REVENUES, NET OF ROYALTIES AND PRODUCTION TAXES	*(Note 4)*	$ 10,011	$ 4,894	$ 4,366
EXPENSES	*(Note 4)*			
Transportation and selling		574	172	148
Operating		1,438	693	620
Purchased product		3,448	1,144	1,019
Administrative		187	83	68
Interest, net	*(Note 7)*	419	45	69
Foreign exchange (gain) loss	*(Note 7)*	(20)	20	37
Depreciation, depletion and amortization		2,153	852	772
Gain on corporate disposition	*(Note 6)*	(51)	–	–
		8,148	3,009	2,733
NET EARNINGS BEFORE THE UNDERNOTED		1,863	1,885	1,633
Income tax expense	*(Note 8)*	618	631	633
Distributions on Subsidiary Preferred Securities, net of tax	*(Note 15)*	20	–	–
NET EARNINGS FROM CONTINUING OPERATIONS		1,225	1,254	1,000
NET (LOSS) EARNINGS FROM DISCONTINUED OPERATIONS	*(Note 5)*	(1)	33	21
NET EARNINGS		$ 1,224	$ 1,287	$ 1,021
DISTRIBUTIONS ON PREFERRED SECURITIES, NET OF TAX	*(Note 16)*	3	4	5
NET EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS		$ 1,221	$ 1,283	$ 1,016
NET EARNINGS FROM CONTINUING OPERATIONS PER COMMON SHARE	*(Note 20)*			
Basic		$ 2.92	$ 4.89	$ 3.94
Diluted		$ 2.87	$ 4.77	$ 3.87
NET EARNINGS PER COMMON SHARE	*(Note 20)*			
Basic		$ 2.92	$ 5.02	$ 4.02
Diluted		$ 2.87	$ 4.90	$ 3.95

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

For the years ended December 31 ($ millions)		2002	2001	2000
RETAINED EARNINGS, BEGINNING OF YEAR				
As previously reported		$ 3,689	$ 3,721	$ 2,788
Retroactive adjustment for change in accounting policy	*(Note 2)*	(59)	(42)	(24)
As restated		3,630	3,679	2,764
Net Earnings		1,224	1,287	1,021
Dividends on Common Shares & Other Distributions, net of tax	*(Note 20)*	(170)	(1,286)	(106)
Other Adjustments	*(Note 20)*	–	(50)	–
RETAINED EARNINGS, END OF YEAR		$ 4,684	$ 3,630	$ 3,679

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEET

As at December 31 ($ millions)		2002	2001
ASSETS			
Current Assets			
Cash and cash equivalents		$ 212	$ 963
Accounts receivable and accrued revenue		2,052	623
Inventories	*(Note 9)*	543	87
Assets of discontinued operations	*(Note 5)*	1,482	–
		4,289	1,673
Capital Assets, net	*(Notes 4, 10)*	23,770	8,162
Investments and Other Assets	*(Note 11)*	377	237
Assets of Discontinued Operations	*(Note 5)*	–	728
Goodwill	*(Note 3)*	2,886	–
	(Note 4)	$ 31,322	$ 10,800
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable and accrued liabilities		$ 2,390	$ 824
Income tax payable		14	656
Liabilities of discontinued operations	*(Note 5)*	825	–
Short-term debt	*(Note 12)*	438	–
Current portion of long-term debt	*(Note 13)*	212	160
		3,879	1,640
Long-Term Debt	*(Note 13)*	7,395	2,210
Deferred Credits and Other Liabilities	*(Note 14)*	585	325
Future Income Taxes	*(Note 8)*	5,212	2,060
Liabilities of Discontinued Operations	*(Note 5)*	–	586
Preferred Securities of Subsidiary	*(Note 15)*	457	–
		17,528	6,821
Shareholders' Equity			
Preferred securities	*(Note 16)*	126	126
Share capital	*(Note 17)*	8,732	196
Share options, net	*(Note 3)*	133	–
Paid in surplus		61	27
Retained earnings		4,684	3,630
Foreign currency translation adjustment	*(Note 2)*	58	–
		13,794	3,979
		$ 31,322	$ 10,800

COMMITMENTS AND CONTINGENCIES *(Note 21)*

Approved by the Board

Director

Director

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31 ($ millions, except per share amounts)		2002	2001	2000
OPERATING ACTIVITIES				
Net earnings from continuing operations		$ 1,225	$ 1,254	$ 1,000
Depreciation, depletion and amortization		2,153	852	772
Future income taxes	*(Note 8)*	667	134	470
Other		(266)	19	36
Cash flow from continuing operations		3,779	2,259	2,278
Cash flow from discontinued operations		42	47	25
Cash flow		3,821	2,306	2,303
Net change in other assets and liabilities		(22)	(63)	(74)
Net change in non-cash working capital from continuing operations	*(Note 20)*	(1,325)	578	2
Net change in non-cash working capital from discontinued operations		97	(47)	(2)
		2,571	2,774	2,229
INVESTING ACTIVITIES				
Business combination with Alberta Energy Company Ltd.	*(Note 3)*	(128)	–	–
Capital expenditures	*(Note 4)*	(4,940)	(1,955)	(1,466)
Proceeds on disposal of capital assets		566	47	193
Corporate (acquisitions) and dispositions	*(Note 6)*	93	84	(948)
Net change in investments and other		64	30	(122)
Net change in non-cash working capital from continuing operations	*(Note 20)*	293	88	42
Discontinued operations		(10)	9	(20)
		(4,062)	(1,697)	(2,321)
FINANCING ACTIVITIES				
Issuance of short-term debt		438	440	469
Repayment of short-term debt		–	(690)	(219)
Issuance of long-term debt		2,354	1,566	76
Repayment of long-term debt		(1,886)	(399)	(136)
Issuance of common shares	*(Note 17)*	139	48	86
Repurchase of common shares		–	(7)	(8)
Dividends on common shares	*(Note 20)*	(167)	(1,282)	(101)
Payments to preferred securities holders		(31)	(7)	(9)
Net change in non-cash working capital from continuing operations	*(Note 20)*	(5)	1	–
Discontinued operations		(13)	–	–
Other		(82)	–	–
		747	(330)	158
DEDUCT: FOREIGN EXCHANGE (GAIN) LOSS ON CASH AND CASH EQUIVALENTS HELD IN FOREIGN CURRENCY		7	(19)	1
(DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(751)	766	65
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		963	197	132
CASH AND CASH EQUIVALENTS, END OF YEAR		$ 212	$ 963	$ 197
CASH FLOW PER COMMON SHARE	*(Note 20)*			
Basic		$ 9.15	$ 9.02	$ 9.11
Diluted		$ 8.99	$ 8.81	$ 8.95
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
Interest paid		$ 416	$ 73	$ 84
Income taxes paid		$ 1,014	$ 34	$ 12

See accompanying Notes to Consolidated Financial Statements

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of EnCana Corporation and its subsidiaries, and are presented in accordance with Canadian generally accepted accounting principles.

Investments in jointly controlled companies, jointly controlled partnerships (collectively called "affiliates") and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

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

B) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements requires that Management make estimates and assumptions and use judgement regarding assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Specifically, amounts recorded for depreciation, depletion, amortization and future dismantlement and site restoration costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the Consolidated Financial Statements of future periods could be material.

C) Revenue Recognition

Revenues associated with the sales of the Company's natural gas, natural gas liquids ("NGLs") and crude oil owned by the Company are recognized when title passes from the Company to its customer. Crude oil and natural gas produced and sold by the Company below or above its working interest share in the related resource properties results in production underliftings or overliftings. Underliftings are recorded as inventory and overliftings are recorded as deferred revenue.

Revenues associated with the sale of transportation and natural gas storage services are recognized when the services are provided.

D) Foreign Currency Translation

In conjunction with the business combination described in Note 3, the Company reviewed its accounting practices for operations outside of Canada and determined that such operations are self-sustaining. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at year end exchange rates, while revenues and expenses are translated using average annual rates. Translation gains and losses relating to the self-sustaining foreign operations are included as a separate component of shareholders' equity.

Debt payable in U.S. dollars is translated into Canadian dollars at the year end exchange rate, with any resulting adjustment recorded in the Consolidated Statement of Earnings or as a foreign currency translation adjustment in the Consolidated Balance Sheet for self-sustaining operations (see Note 2).

E) Employee Benefit Plans

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

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

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

F) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, the Company records future income taxes for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates with the adjustment being recognized in earnings in the period that the change occurs.

G) Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings less the effect of Distributions on Preferred Securities, net of tax, by the weighted average number of common shares outstanding during the period. Basic cash flow per common share is computed by dividing cash flow by the weighted average number of common shares outstanding during the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price.

H) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with a maturity of three months or less when purchased.

I) Inventories

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

J) Capital Assets

Upstream

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

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves, before royalties. For purposes of this calculation, oil is converted to gas on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the disposal of properties are normally deducted from the full cost pool without recognition of gain or loss. Costs of major development projects and exploration on significant unproved properties, together with related land costs, are excluded, on a cost centre basis, from costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred.

A ceiling test is applied to ensure that capitalized costs do not exceed the sum of estimated undiscounted, unescalated future net revenues from proved reserves, plus unimpaired unproved property costs, less future development costs and related production, future dismantlement and site restoration, interest, administrative costs and applicable taxes. The ceiling test calculations utilize the Company's year end sales prices and costs.

Syncrude Capital assets associated with the Syncrude project are accumulated, at cost, in a separate cost centre. Substantially all of these costs are amortized using the unit-of-production method based on the estimated proved developed reserves applicable to the project.

Midstream

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

K) Capitalization of Costs

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

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

L) Amortization of Investments and Other Assets

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

M) Goodwill

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

N) Future Dismantlement and Site Restoration Costs

Estimated future dismantlement and site restoration costs of natural gas and crude oil assets are provided for using the unit-of-production method. Such costs for Midstream facilities are provided for over the estimated service lives of the assets. Provisions for future dismantlement and site restoration costs are included in depreciation, depletion and amortization expense in the Consolidated Statement of Earnings. Actual expenditures incurred are charged against the accumulated provision.

O) Stock-based Compensation

The Company does not record compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors.

Obligations for cash payments under the Company's share appreciation rights and deferred share units are accrued as compensation expense over the vesting period. Fluctuations in the price of the Company's common shares will change the accrued compensation expense and are recognized prospectively when they occur.

P) Derivative Financial Instruments

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

The Company formally documents the permitted use of derivative financial instruments and specifically ties their use to the maximization of the netback price of the Company's proprietary production and the optimization of specific assets and obligations. When applicable, the Company also documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategies for undertaking various hedge transactions. This process includes linking these derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also assesses, both at the hedges' inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company enters into hedges with respect to a portion of its oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. These transactions generally are swaps, collars or options and are entered into with major financial institutions or commodities trading institutions. Gains and losses from these derivative financial instruments are recognized in oil and gas revenues as the related sales occur.

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

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

The Company also purchases foreign exchange forward contracts to hedge anticipated sales to customers in the United States and the related accounts receivable. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Q) Reclassification

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

NOTE 2 CHANGES IN ACCOUNTING POLICIES AND PRACTICES

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. Specifically, the Company is now required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period end exchange rate with any resulting adjustment recorded in the Consolidated Statement of Earnings or as a foreign currency translation adjustment in the Consolidated Balance Sheet for self-sustaining entities. 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 in net earnings of $28 million for the year ended December 31, 2002 (2001 – $17 million decrease; 2000 – $18 million decrease). 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 and other liabilities of $92 million, as well as a reduction in investments and other assets and retained earnings of $59 million (2000 – $42 million).

In conjunction with the business combination described in Note 3, the Company reviewed its accounting practices for operations outside of Canada and determined that such operations are self-sustaining. The accounts of self-sustaining foreign operations are translated using the current rate method, whereby assets and liabilities are translated at period-end exchange rates, while revenues and expenses are translated using average rates for the period. Translation gains and losses relating to the operations 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, depletion and amortization, which were translated on the same basis as the related assets.

This change in practice was adopted prospectively beginning April 5, 2002, and resulted in an increase in net earnings of $2 million for the year ended December 31, 2002.

NOTE 3 BUSINESS COMBINATION WITH ALBERTA ENERGY COMPANY LTD.

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 option holders 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.

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 allocation to assets and liabilities acquired as of April 5, 2002 is shown below:

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 ("Share options")		167
Transaction costs		150
Total purchase price		8,714
Plus: Fair value of liabilities assumed		
Current liabilities		1,781
Long-term debt		4,843
Project financing debt		604
Preferred securities		458
Other non-current liabilities		193
Future income taxes		2,647
Total Purchase Price and Liabilities Assumed		$ 19,240
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
Goodwill Allocation:		
Onshore North America		$ 2,808
Midstream & Marketing		78
		2,886
Discontinued Operations		191
Total Goodwill Allocation		$ 3,077

NOTE 4 SEGMENTED INFORMATION

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

- Onshore North America includes the Company's North America onshore exploration for, and production of, natural gas, natural gas liquids and crude oil.
- Offshore & International combines the following two divisions:
  - ~ the Offshore & International Operations Division develops the reserves associated with offshore and international discoveries. The Division currently has production in Ecuador and the U.K. central North Sea and major developments in the East Coast of Canada, Gulf of Mexico and the U.K. central North Sea.
  - ~ the Offshore & New Ventures Exploration Division includes the Company's exploration activity in the Canadian East Coast, the North American frontier region, the Gulf of Mexico, the U.K. central North Sea, the Middle East, Africa, Australia and Latin America.
- Midstream & Marketing includes gas storage operations, natural gas liquids processing and power generation operations, as well as, marketing activity under which the Company purchases and takes delivery of product from others and delivers product to customers under transportation arrangements not utilized for the Company's own production.

The Company reports its segmented financial results showing revenue prior to all royalty payments, both cash and in-kind, consistent with Canadian disclosure practices for the oil and gas industry.

Operations that have been discontinued are disclosed in Note 5.

Results of Operations *(for the years ended December 31)*

	Onshore North America			Offshore & International			Midstream & Marketing		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues									
Gross revenue	$ 6,152	$ 3,569	$ 3,072	$ 701	$ 171	$ 154	$ 4,133	$ 1,462	$ 1,401
Royalties and production taxes	809	303	259	180	–	–	–	–	–
Revenues, net of royalties and production taxes	5,343	3,266	2,813	521	171	154	4,133	1,462	1,401
Expenses									
Transportation and selling	385	137	123	53	19	9	136	16	16
Operating	952	429	345	135	17	23	351	247	252
Purchased product	–	–	–	–	–	–	3,448	1,144	1,019
Depreciation, depletion and amortization	1,776	703	596	260	96	129	62	20	17
Segment Income	$ 2,230	$ 1,997	$ 1,749	$ 73	$ 39	$ (7)	$ 136	$ 35	$ 97

	Corporate			Consolidated		
	2002	2001	2000	2002	2001	2000
Revenues						
Gross revenue	$ 14	$ (5)	$ (2)	$ 11,000	$ 5,197	$ 4,625
Royalties and production taxes	–	–	–	989	303	259
Revenues, net of royalties and production taxes	14	(5)	(2)	10,011	4,894	4,366
Expenses						
Transportation and selling	–	–	–	574	172	148
Operating	–	–	–	1,438	693	620
Purchased product	–	–	–	3,448	1,144	1,019
Depreciation, depletion and amortization	55	33	30	2,153	852	772
Gain on corporate disposition	(51)	–	–	(51)	–	–
Segment Income	10	(38)	(32)	2,449	2,033	1,807
Administrative	187	83	68	187	83	68
Interest, net	419	45	69	419	45	69
Foreign exchange (gain) loss	(20)	20	37	(20)	20	37
	586	148	174	586	148	174
Net Earnings Before Income Tax	(576)	(186)	(206)	1,863	1,885	1,633
Income tax expense	618	631	633	618	631	633
Distributions on Subsidiary Preferred Securities, net of tax	20	–	–	20	–	–
Net Earnings from Continuing Operations	$ (1,214)	$ (817)	$ (839)	$ 1,225	$ 1,254	$ 1,000

Geographic and Product Information *(for the years ended December 31)*

ONSHORE NORTH AMERICA

	Produced Gas and NGLs					
	Canada			U.S. Rockies		
	2002	2001	2000	2002	2001	2000
Revenues						
Gross revenue	$ 3,451	$ 2,544	$ 1,837	$ 869	$ 118	$ 27
Royalties and production taxes	419	141	105	196	39	9
Revenues, net of royalties and production taxes	3,032	2,403	1,732	673	79	18
Expenses						
Transportation and selling	235	112	98	91	–	–
Operating	407	175	131	64	17	2
Operating Cash Flow	$ 2,390	$ 2,116	$ 1,503	$ 518	$ 62	$ 16

	Conventional Crude Oil			Syncrude			Total Onshore North America		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues									
Gross revenue	$ 1,463	$ 907	$ 1,208	$ 369	$ –	$ –	$ 6,152	$ 3,569	$ 3,072
Royalties and production taxes	190	123	145	4	–	–	809	303	259
Revenues, net of royalties and production taxes	1,273	784	1,063	365	–	–	5,343	3,266	2,813
Expenses									
Transportation and selling	55	25	25	4	–	–	385	137	123
Operating	317	237	212	164	–	–	952	429	345
Operating Cash Flow	$ 901	$ 522	$ 826	$ 197	$ –	$ –	$ 4,006	$ 2,700	$ 2,345

OFFSHORE & INTERNATIONAL	Ecuador			U.K. North Sea			Other			Total Offshore & International		
	2002	2001	2000	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues												
Gross revenue	$ 541	$ –	$ –	$ 160	$ 171	$ 154	$ –	$ –	$ –	$ 701	$ 171	$ 154
Royalties and production taxes	180	–	–	–	–	–	–	–	–	180	–	–
Revenues, net of royalties and production taxes	361	–	–	160	171	154	–	–	–	521	171	154
Expenses												
Transportation and selling	34	–	–	19	19	9	–	–	–	53	19	9
Operating	83	–	–	18	17	23	34	–	–	135	17	23
Operating Cash Flow	$ 244	$ –	$ –	$ 123	$ 135	$ 122	$ (34)	$ –	$ –	$ 333	$ 135	$ 122

MIDSTREAM & MARKETING	Midstream			Marketing			Total Midstream & Marketing		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues									
Gross revenue	$ 760	$ 260	$ 311	$ 3,373	$ 1,202	$ 1,090	$ 4,133	$ 1,462	$ 1,401
Expenses									
Transportation and selling	–	–	–	136	16	16	136	16	16
Operating	331	228	229	20	19	23	351	247	252
Purchased product	265	–	–	3,183	1,144	1,019	3,448	1,144	1,019
Operating Cash Flow	$ 164	$ 32	$ 82	$ 34	$ 23	$ 32	$ 198	$ 55	$ 114

Capital Expenditures

Years ended December 31	2002	2001	2000
Onshore North America	$ 3,662	$ 1,356	$ 1,071
Offshore & International	1,126	407	266
Midstream & Marketing	87	165	90
Corporate	65	27	39
Total	$ 4,940	$ 1,955	$ 1,466

Additions to Goodwill

The only additions to goodwill during the year were as a result of the business combination transaction described in Note 3.

Capital Assets and Total Assets

As at December 31	Capital Assets		Total Assets	
	2002	2001	2002	2001
Onshore North America	$ 18,994	$ 6,442	$ 22,977	$ 6,970
Offshore & International	3,710	1,154	4,023	1,247
Midstream & Marketing	874	458	2,348	849
Corporate	192	108	492	1,006
Assets of Discontinued Operations	–	–	1,482	728
Total	$ 23,770	$ 8,162	$ 31,322	$ 10,800

Export Sales

Sales of natural gas, crude oil and natural gas liquids produced or purchased in Canada made outside of Canada were $2,093 million (2001 – $1,216 million; 2000 – $1,063 million).

Major Customers

The Company does not rely on any one customer for 10 percent of its consolidated Revenues, Net of Royalties and Production Taxes.

All of the Company's crude oil produced in Ecuador is sold to a single marketing company. All payments are secured by letters of credit from a major financial institution.

NOTE 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 & Marketing segment. Accordingly, these operations have been accounted for as discontinued operations.

On July 9, 2002, the Company announced that it planned to sell its 70% equity investment in the Cold Lake Pipeline System and its 100% interest in the Express Pipeline System. Both crude oil pipeline systems were acquired in the business combination with Alberta Energy Company Ltd. 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 and the Cold Lake pipeline. The financial results for the year ended December 31, 2002, shown below, include tariff revenue of $54 million paid by the Company for services on Express. On November 19, 2002, the Company announced that it had entered into agreements to sell its discontinued pipelines operations for approximately $1.6 billion including the assumption of long-term debt (see Note 22).

As the wind-down of the merchant energy operation was substantially complete at December 31, 2002, and the midstream pipelines were sold subsequent to year end, all discontinued operations at December 31, 2002 have been classified as current on the Consolidated Balance Sheet.

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, 2001 and 2000. It does not include any financial information related to Midstream – Pipelines for those years as EnCana did not own the pipelines being discontinued at that time.

Consolidated Statement of Earnings

For the years ended December 31	Merchant Energy			Midstream – Pipelines			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Revenues	$ 1,454	$ 4,085*	$ 3,025	$ 212	$ –	$ –	$ 1,666	$ 4,085	$ 3,025
Expenses									
Operating	–	–	–	78	–	–	78	–	–
Purchased product	1,465	3,983*	2,961	–	–	–	1,465	3,983	2,961
Administrative	35	43	26	–	–	–	35	43	26
Interest, net	–	–	–	30	–	–	30	–	–
Foreign exchange (gain)	–	–	–	(3)	–	–	(3)	–	–
Depreciation, depletion and amortization	–	4	3	27	–	–	27	4	3
Loss on discontinuance	30	–	–	–	–	–	30	–	–
	1,530	4,030	2,990	132	–	–	1,662	4,030	2,990
Net (Loss) Earnings Before Income Tax	(76)	55	35	80	–	–	4	55	35
Income tax (recovery) expense	(27)	22	14	32	–	–	5	22	14
Net (Loss) Earnings from Discontinued Operations	$ (49)	$ 33	$ 21	$ 48	$ –	$ –	$ (1)	$ 33	$ 21

* 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 Revenues 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

As at December 31	Merchant Energy		Midstream – Pipelines		Total	
	2002	2001	2002	2001	2002	2001
Assets						
Cash and cash equivalents	$ –	$ –	$ 68	$ –	$ 68	$ –
Accounts receivable and accrued revenue	–	632	31	–	31	632
Inventories	–	70	1	–	1	70
	–	702	100	–	100	702
Capital assets, net	–	9	817	–	817	9
Investments and other assets	–	17	374	–	374	17
Goodwill	–	–	191	–	191	–
	–	728	1,482	–	1,482	728
Liabilities						
Accounts payable and accrued liabilities	5	584	40	–	45	584
Income tax payable	–	–	17	–	17	–
Current portion of long-term debt	–	–	23	–	23	–
	5	584	80	–	85	584
Long-term debt	–	–	576	–	576	–
Deferred credits and other liabilities	–	2	–	–	–	2
Future income taxes	–	–	164	–	164	–
	5	586	820	–	825	586
Net Assets of Discontinued Operations	$ (5)	$ 142	$ 662	$ –	$ 657	$ 142

NOTE 6 CORPORATE (ACQUISITIONS) AND DISPOSITIONS

Years ended December 31	2002	2001	2000
Acquisitions*			
Montana Power	$ –	$ –	$ (689)
Scott and Telford	–	–	(259)
Other	–	(72)	–
	–	(72)	(948)
Dispositions	93	156	–
	$ 93	$ 84	$ (948)

* Acquisitions include all corporate acquisitions other than the business combination described in Note 3.

In December 2002, the Company sold its investment in EnCana Suffield Gas Pipeline Inc. for total proceeds of $93 million, with a gain on disposal of $51 million.

During 2000, the Company purchased the petroleum and natural gas exploration and production and midstream and marketing divisions of The Montana Power Company. The acquisition was accounted for by the purchase method, with the results reflected in the Company's operations from November 1, 2000.

During 2000, the Company purchased interests in the Scott (13.5%) and Telford lands on block 15/22 (26%) surrounding the Scott/Telford producing unit. The acquisition was accounted for by the purchase method, with the results reflected in the Company's operations from January 7, 2000.

These acquisitions have been accounted for as follows:

	Montana Power	Scott and Telford
Net Assets Acquired		
Working capital	$ (66)	$ 4
Capital assets	790	283
Other assets	77	–
Future income taxes	(91)	(28)
Site restoration costs assumed	(21)	–
Cash Consideration Paid	$ 689	$ 259

NOTE 7 INTEREST, NET AND FOREIGN EXCHANGE (GAIN) LOSS

Interest, Net

Years ended December 31	2002	2001	2000
Interest Expense – Long-term Debt	$ 358	$ 80	$ 84
Early Retirement of Long-term Debt	54	–	–
Interest Expense – Other	18	–	–
Interest Income	(11)	(35)	(15)
	$ 419	$ 45	$ 69

The Company has entered into a series of one or more interest rate swaps, foreign exchange swaps and option transactions on certain of its long-term notes and debentures detailed below (see also Note 13). The net effect of these transactions reduced interest costs in 2002 by $28 million (2001 – $15 million; 2000 – $6 million).

	Principal Amount	Indenture Interest	Net Swap to	Effective Rate
5.50% due on March 17, 2003 $100 million	US$71 million	C$ Fixed	US$ Floating*	3 month LIBOR less 68 basis points
5.80% due June 2, 2008	US$71 million	C$ Fixed	US$ Fixed*	4.80%
$225 million	C$125 million	C$ Fixed	C$ Floating	3 month Bankers' Acceptance less 5 basis points
7.50% due August 25, 2006 $100 million	US$73 million	C$ Fixed	US$ Fixed*	4.14%
8.40% due December 15, 2004 $100 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 41 basis points
8.75% due November 9, 2005	US$73 million	C$ Fixed	US$ Fixed*	4.99%
$200 million	US$73 million	C$ Fixed	US$ Floating*	3 month LIBOR less 4 basis points

* These instruments have been subject to multiple swap transactions.

Foreign Exchange (Gain) Loss

Years ended December 31	2002	2001	2000
Foreign Exchange (Gain) Loss on Translation of U.S. Dollar Debt	$ (34)	$ 55	$ 36
Other Foreign Exchange (Gains) Losses	14	(35)	1
	$ (20)	$ 20	$ 37

NOTE 8 INCOME TAXES

Years ended December 31	2002	2001	2000
Provision for Income Taxes			
Current			
Canada	$ (30)	$ 504	$ 174
United States	(49)	(9)	(11)
Ecuador	27	–	–
United Kingdom	–	–	–
Other	3	2	–
	(49)	497	163
Future	667	134	470
	$ 618	$ 631	$ 633

The net future income tax liability is comprised of:

As at December 31	2002	2001
Future Tax Liabilities		
Capital assets in excess of tax values	$ 4,829	$ 1,903
Timing of partnership items	809	292
Future Tax Assets		
Net operating losses carried forward	(320)	(135)
Other	(106)	–
Net Future Income Tax Liability	$ 5,212	$ 2,060

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

Years ended December 31	2002	2001	2000
Net Earnings Before Income Taxes	$ 1,863	$ 1,885	$ 1,633
Canadian Statutory Rate	42.3%	42.8%	44.7%
Expected Income Taxes	788	807	730
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	232	113	104
Canadian resource allowance	(331)	(258)	(245)
Large corporations tax	35	16	16
Statutory rate differences	(57)	(19)	9
Effect of tax rate changes	(33)	(81)	–
Other	(16)	53	19
	$ 618	$ 631	$ 633
Effective Tax Rate	33.2%	33.5%	38.8%

The approximate amounts of tax pools available are as follows:

As at December 31	2002	2001
Canada	$ 7,364	$ 2,726
United States	3,435	966
Ecuador	1,312	–
United Kingdom	195	148
	$ 12,306	$ 3,840

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

NOTE 9 INVENTORIES

As at December 31	2002	2001
Product		
Onshore North America	$ 45	$ 3
Offshore & International	9	–
Midstream & Marketing	377	67
Parts, Supplies and Other	112	17
	$ 543	$ 87

NOTE 10 CAPITAL ASSETS

As at December 31	2002			2001		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Onshore North America						
Canada conventional	$ 21,107	$ (7,254)	$ 13,853	$ 11,790	$ (5,936)	$ 5,854
U.S. conventional	4,133	(406)	3,727	643	(55)	588
Syncrude	1,440	(26)	1,414	–	–	–
Total Onshore North America	26,680	(7,686)	18,994	12,433	(5,991)	6,442
Offshore & International						
Ecuador	1,658	(115)	1,543	–	–	–
United Kingdom	695	(208)	487	516	(136)	380
Other	2,019	(339)	1,680	1,018	(244)	774
Total Offshore & International	4,372	(662)	3,710	1,534	(380)	1,154
Midstream & Marketing	1,005	(131)	874	569	(111)	458
Corporate	302	(110)	192	202	(94)	108
	$ 32,359	$ (8,589)	$ 23,770	$ 14,738	$ (6,576)	$ 8,162

* Depreciation, depletion and amortization

Included in Midstream is $75 million (2001 – nil) related to cushion gas, required to operate the gas storage facilities, which is not subject to depletion.

Administrative costs are not capitalized as part of the capital expenditures in Onshore North America and Offshore & International.

At December 31, 2002, costs in respect of significant unproved properties and major development projects excluded from depletable costs were:

	2002	2001	2000
Onshore North America	$ 829	$ 110	$ 23
Offshore & International	1,110	624	450
	$ 1,939	$ 734	$ 473

The prices used in the ceiling test evaluation of the Company's conventional oil and natural gas reserves at December 31, 2002, were:

Onshore North America		
Canada		
Natural gas	($ per thousand cubic feet)	6.05
Crude oil	($ per barrel)	30.29
Natural gas liquids	($ per barrel)	34.76
U.S. Rockies		
Natural gas	(US$ per thousand cubic feet)	3.14
Crude oil	(US$ per barrel)	31.23
Natural gas liquids	(US$ per barrel)	26.52
Offshore & International		
Ecuador – crude oil	(US$ per barrel)	21.62
U.K. – natural gas	(US$ per thousand cubic feet)	3.06
U.K. – crude oil	(US$ per barrel)	25.66
U.K. – natural gas liquids	(US$ per barrel)	24.19

NOTE 11 INVESTMENTS AND OTHER ASSETS

As at December 31		2002	2001
Equity Investments	*(Note A)*	$ 98	$ 22
Value Added Tax Recoverable		89	–
Marketing Contracts		43	48
Deferred Financing Costs		44	38
Deferred Pension Costs		23	33
Other		80	96
		$ 377	$ 237

A) Included in Equity Investments is the following:

i. A 36% indirect equity investment in Oleoducto Trasandino, which owns a crude oil pipeline that ships crude oil from the producing areas of Argentina to refineries in Chile.

ii. A 31% indirect equity investment in Oleoducto de Crudos Pesados (OCP) Ltd., which is the owner of a crude oil pipeline, currently under construction in Ecuador, that will ship crude oil from the producing areas of Ecuador to a new export marine terminal.

Summary financial information for the Company's share of these equity investments, on a combined basis, is as follows:

Years ended December 31	2002	2001
Current Assets	$ 76	$ –
Non-current Assets	509	–
Current Liabilities	49	–
Non-recourse Debt	446	–
Non-current Liabilities	3	–
Revenues	$ 35	$ –
Net Earnings	18	–
Equity Earnings (included in Midstream Revenues)	$ 9	$ –

NOTE 12 SHORT-TERM DEBT

At December 31, 2002, one of the Company's subsidiaries had in place short-term debt of $438 million. The borrowing is under a non-revolving credit facility, which has an expiry date of May 2003 with a provision for an extension for a further six months at the option of the lender and upon the request from the subsidiary. This facility was repaid in full subsequent to year end and then cancelled.

NOTE 13 LONG-TERM DEBT

As at December 31		2002	2001
Canadian Dollar Denominated Debt			
Revolving credit and term loan borrowings	*(Note B)*	$ 1,388	$ 37
Unsecured notes and debentures	*(Note C)*	1,825	125
		3,213	162
U.S. Dollar Denominated Debt			
U.S. revolving credit and term loan borrowings	*(Note D)*	696	–
U.S. unsecured notes and debentures	*(Note E)*	3,608	2,208
		4,304	2,208
Increase in Value of Debt Acquired	*(Note F)*	90	–
Current Portion of Long-term Debt	*(Note G)*	(212)	(160)
		$ 7,395	$ 2,210

A) Overview

Revolving credit and term loans

At December 31, 2002, the Company had in place revolving credit and term loan facilities for $4.25 billion. One of the facilities, totalling $4 billion, consists of two tranches of $2 billion each. One tranche is fully revolving for a 364-day period with provision for extensions at the option of the lenders and upon notice from the Company. If not extended, this tranche converts to a non-revolving reducing loan for a term of one year. The second tranche is fully revolving for a period of three years from the date of the agreement, December 2002. The facility is unsecured and bears interest at either the lenders' rates for Canadian prime commercial loans, U.S. base rate loans, Bankers' Acceptances rates, or at LIBOR plus applicable margins. The other credit facility, in the amount of $250 million, was cancelled subsequent to year-end.

At December 31, 2002, the Company's subsidiaries had in place two unsecured credit facilities totalling $143 million. The facilities are unsecured and fully revolving for a 364-day period with a provision for extensions at the option of the lenders and upon notice from the respective subsidiary. If not extended, the facilities convert to non-revolving reducing loans for terms of 3 and 5 years, respectively. These facilities bear interest at either the lenders' rates for Canadian prime commercial loans, U.S. base rate loans, Bankers' Acceptances rates, or at LIBOR plus applicable margins.

One of the Company's partnerships has a credit agreement, consisting of a term loan facility, senior secured notes and a levelization account, relating to the construction of a cogeneration plant. The term loan bears interest at the prevailing prime lending rate plus 0.25%. The notes bear interest at the prevailing prime lending rate plus 1.25%. The partnership also has an option under the credit agreement to use an average Bankers' Acceptances rate plus a margin that will vary during the term. The levelization account accumulates interest at the yield rate of the most recent Government of Canada bond issue with a 20-year maturity as of January 20th each year. The term loan and senior notes are secured by the project facilities.

Revolving credit and term loan borrowings include Bankers' Acceptances and Commercial Paper of $1,376 million (2001 – nil) maturing at various dates with a weighted average interest rate of 3.04%. These amounts are fully supported and Management expects that they will continue to be supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

Standby fees paid in 2002 relating to revolving credit and term loan agreements were approximately $4 million (2001 – $1 million).

Unsecured notes and debentures

Unsecured notes and debentures include medium term notes and senior notes that are issued from time to time under trust indentures. The Company's current medium term note program was renewed in 2002 with $700 million unutilized at December 31, 2002. The notes may be denominated in Canadian dollars, or in foreign currencies.

The Company has in place a shelf prospectus for U.S. Unsecured Notes in the amount of US$2.0 billion under the Multijurisdictional Disclosure System. The shelf prospectus provides that debt securities in U.S. dollars or other foreign currencies may be issued from time to time in one or more series. Terms of the notes, including interest at either fixed or floating rates and expiry dates, are determined by reference to market conditions at the date of issue.

B) Revolving Credit and Term Loan Borrowings

	2002	2001
Bankers' Acceptances	$ 435	$ –
Commercial Paper	916	–
Cogeneration Facility, matures March 31, 2016	37	37
	$ 1,388	$ 37

C) Unsecured Notes and Debentures

	2002	2001
8.15% due July 31, 2003	$ 100	$ –
6.60% due June 30, 2004	50	–
7.00% due December 1, 2004	100	–
5.95% due October 1, 2007	200	–
5.30% due December 3, 2007	300	–
5.95% due June 2, 2008	100	–
5.80% due June 2, 2008	125	125
5.80% due June 19, 2008	100	–
6.10% due June 1, 2009	150	–
7.15% due December 17, 2009	150	–
8.50% due March 15, 2011	50	–
7.10% due October 11, 2011	200	–
7.30% due September 2, 2014	150	–
5.50%/6.20% due June 23, 2028	50	–
	$ 1,825	$ 125

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

	US$ Amount	2002	2001
Commercial Paper	$ 16	$ 25	$ –
LIBOR Loan	425	671	–
	$ 441	$ 696	$ –

E) U.S. Unsecured Notes and Debentures

	US$ Amount	2002	2001
Floating Rate			
5.50% due March 17, 2003	$ 71*	$ 112	113
8.40% due December 15, 2004	73*	116	117
8.75% due November 9, 2005	73*	115	117
Fixed Rate			
7.90% due January 24, 2002	–	–	80
8.10% due May 22, 2002	–	–	80
8.75% due November 9, 2005	73*	115	116
7.50% due August 25, 2006	73*	115	116
5.80% due June 2, 2008	71*	112	113
7.65% due September 15, 2010	200	316	–
6.30% due November 1, 2011	500	790	798
8.125% due September 15, 2030	300	474	–
7.20% due November 1, 2031	350	553	558
7.375% due November 1, 2031	500	790	–
	$ 2,284	$ 3,608	$ 2,208

* The Company has entered into a series of cross-currency and interest rate swap transactions that effectively convert these notes to U.S. dollars. The effective U.S. dollar principal is shown in the table.

F) Increase in Value of Debt Acquired

Certain of the notes and debentures of the Company were acquired in the business combination described in Note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount of the debt is being amortized over the remaining life of the outstanding debt acquired, approximately 24 years.

G) Current Portion of Long-term Debt

	2002	2001
7.90% Medium Term Note due January 24, 2002	$ –	$ 80
8.10% Debenture due May 22, 2002	–	80
5.50% Medium Term Note due March 17, 2003	112	–
8.15% Debenture due July 31, 2003	100	–
	$ 212	$ 160

H) Mandatory Five Year Debt Payments

	2003	2004	2005	2006	2007	Thereafter	**Total**
	$ 212	$ 266	$ 230	$ 115	$ 500	$ 6,194	**$ 7,517**

The amount due in 2003 excludes Bankers' Acceptances and Commercial Paper, which are fully supported by revolving credit and term loan facilities that have no repayment requirements within the next year.

NOTE 14 DEFERRED CREDITS AND OTHER LIABILITIES

As at December 31	**2002**	2001
Future Dismantlement and Site Restoration Costs	**$ 494**	$ 255
Other	**91**	70
	$ 585	$ 325

NOTE 15 PREFERRED SECURITIES OF SUBSIDIARY

	Rate *(%)*	Currency	Principal Amount	Maturity Date
Preferred Securities	8.50	Canadian	$200	September 30, 2048
Preferred Securities	9.50	U.S.	$150	September 30, 2048

The Preferred Securities of Subsidiary are unsecured junior subordinated debentures. Subject to certain conditions, the Company's subsidiary, Alberta Energy Company Ltd., has the right to defer payments of interest on the securities for up to 20 consecutive quarterly periods. The subsidiary may satisfy its obligation to pay deferred interest or the principal amount by delivering sufficient equity securities to the Trustee. The Preferred Securities of Subsidiary were acquired in the business combination described in Note 3 and were accounted for at their fair value at the date of acquisition. The difference between the fair value and the principal amount is being amortized over the remaining life of the Preferred Securities of Subsidiary.

The Company recognized $31 million ($20 million, net of tax) for distributions on the Preferred Securities of Subsidiary in 2002.

On January 1, 2003, the Company and its subsidiary were amalgamated, and as a result, these Preferred Securities became the direct obligation of EnCana Corporation and they will be included in shareholders' equity in future periods (see Note 22).

NOTE 16 PREFERRED SECURITIES

On March 23, 1999, the Company issued $126 million of Coupon Reset Subordinated Term Securities – Series A due March 23, 2034. Interest is payable semi-annually at a rate of 7% per annum for the first five years and is reset at the Five Year Government of Canada Yield plus 2% on each fifth anniversary of the date of issuance. The securities are redeemable by the Company, in whole or in part, at any time on or after March 23, 2004, at par plus accrued and unpaid interest. The Company has the right to defer, subject to certain conditions, interest for a period of up to five years. The Company may also satisfy its obligation to pay deferred interest, the redemption amount, or the principal amount by delivering sufficient common shares, preferred shares, or other non-redeemable preferred shares to the Trustee.

With respect to the Preferred Securities, the Company entered a series of option transactions that result in an effective floating interest rate equal to three-month Bankers' Acceptances rate plus 104 basis points on $126 million.

The Company recognized $5 million ($3 million, net of tax) for distributions on the Preferred Securities in 2002 compared with $7 million ($4 million, net of tax) in 2001 and $9 million ($5 million, net of tax) in 2000. These distributions, net of tax, have been recorded as a direct charge to retained earnings.

NOTE 17 SHARE CAPITAL

Authorized

The Company is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

As at December 31		2002		2001	
		Number	Amount	Number	Amount
Common Shares Outstanding, Beginning of Year		254.9	$ 196	254.8	$ 148
Shares Issued to AEC Shareholders	*(Note 3)*	218.5	8,397	–	–
Shares Issued under Option Plans		5.5	139	1.9	48
Shares Repurchased		–	–	(0.2)	–
Adjustments due to Canadian Pacific Limited Reorganization		–	–	(1.6)	–
Common Shares Outstanding, End of Year		478.9	$ 8,732	254.9	$ 196

Effective October 16, 2002, the Company received approval from the Toronto Stock Exchange for a Normal Course Issuer Bid. Under the bid, the Company may purchase for cancellation up to 23,843,565 of its Common Shares, representing five percent of the 476,871,300 Common Shares outstanding as at October 4, 2002. On October 22, 2002, the Company became entitled to make purchases under the bid for a period of up to one year.

During 2001, the Company implemented a small shareholder-selling program that enabled shareholders that owned 99 or fewer Common Shares of the Company as of October 5, 2001, to sell their shares without incurring any brokerage commission. The program expired on March 5, 2002.

In 2001 and 2000, 0.2 million and 0.3 million Common Shares were repurchased for $7 million and $8 million, respectively. The cost of the repurchases was substantially charged to Paid in Surplus. No Common Shares were repurchased in 2002.

Stock Options

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 ("CPL") 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") in a manner consistent with the provisions of the AEC stock option plan. Options granted under the AEC plan prior to April 21, 1999 expire after seven years and options granted after April 20, 1999 expire after five years. The business combination 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.

EnCana Plan

Pursuant to the terms of a stock option plan, options may be granted to certain key employees to purchase common shares of the Company. Options granted prior to February 27, 1997, are exercisable at half the number of options granted after two years and are fully exercisable after three years. The options expire 10 years after the date granted. Options granted on or after February 27, 1997, and prior to November 4, 1999, are exercisable after three years and expire five years after the date granted. Options granted on or after November 4, 1999, are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, are fully exercisable after three years and expire five years after the date granted. For stock options granted after February 27, 1997, and prior to November 4, 1999, the employees can surrender their options in exchange for, at the election of the Company, cash or a payment in common stock for the difference between the market price and exercise price. Option exercise prices approximate the market price for the common shares on the date the options are issued. In the event of a change in control of the Company, all outstanding options become immediately exercisable.

CPL Replacement Plan

As part of the CPL reorganization, as described in Note 20, CPL stock options were replaced with stock options granted by the Company in a manner that was consistent with the provisions of the CPL stock option plan. Under CPL's stock option plan, options were granted to certain key employees to purchase common shares of CPL at a price not less than the market value of the shares at the grant date. The options expire 10 years after the grant date and, as a result of the reorganization, are all exercisable.

Directors' Plan

Effective April 5, 2002, the Company amended the director stock option plan. Under the terms of the plan, new non-employee directors are given an initial grant of 15,000 options to purchase Common Shares of the Company. Thereafter, there is an annual grant of 7,500 options to each non-employee director. These options, which expire five years after the grant date, are 100 percent exercisable on the earlier of the next annual general meeting following the grant date and the first anniversary of the grant date.

The following tables summarize the information about options to purchase Common Shares:

As at December 31	2002		2001	
	Stock Options	Weighted Average Exercise Price *($)*	Stock Options	Weighted Average Exercise Price *($)*
Outstanding, Beginning of Year	10.5	32.31	6.9	22.61
Granted under EnCana Plan	12.1	48.13	4.5	48.08
Granted under CPL Replacement Plan	–	–	1.5	22.83
Granted under AEC Replacement Plan	13.1	32.01	–	–
Granted under Directors' Plan	0.1	48.04	0.1	39.60
Exercised	(5.5)	25.20	(1.9)	25.82
Forfeited	(0.7)	43.81	(0.6)	37.04
Outstanding, End of Year	29.6	39.74	10.5	32.31
Exercisable, End of Year	17.7	34.10	3.2	22.92

As at December 31, 2002	Outstanding Options			Exercisable Options	
Range of Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*	Number of Options Outstanding *(millions)*	Weighted Average Exercise Price *($)*
13.50 to 19.99	3.5	1.3	18.75	3.5	18.75
20.00 to 24.99	2.1	2.3	22.25	2.1	22.25
25.00 to 29.99	3.2	2.3	26.58	3.2	26.58
30.00 to 43.99	1.9	3.1	38.56	1.7	38.11
44.00 to 53.00	18.9	3.9	47.91	7.2	47.42
	29.6	3.0	39.74	17.7	34.10

At December 31, 2002, there were 12.8 million Common Shares reserved for issuance under stock option plans (2001 – 2.9 million).

The Company does not record compensation expense in the Consolidated Financial Statements for stock options granted to employees and directors. If the fair-value method had been used, the Company's Net Earnings and Net Earnings per Common Share would approximate the following pro forma amounts:

Years ended December 31 ($ millions, except per share amounts)	2002	2001
Compensation Costs	$ 80	$ 39
Net Earnings		
As reported	1,224	1,287
Pro forma	1,144	1,248
Net Earnings per Common Share		
Basic		
As reported	2.92	5.02
Pro forma	2.73	4.87
Diluted		
As reported	2.87	4.90
Pro forma	2.68	4.75

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:

Years ended December 31	2002	2001
Weighted Average Fair Value of Options Granted	$ 13.31	$ 13.53
Risk-free Interest Rate	4.29%	4.24%
Expected Lives *(years)*	3.00	3.00
Expected Volatility	0.35	0.35
Annual Dividend per Share	$ 0.40	$ 0.40

NOTE 18 COMPENSATION PLANS

Pensions

The Company sponsors both defined benefit and defined contribution plans providing pension and other retirement and post-employment benefits to substantially all of its employees. The Syncrude joint venture ("Syncrude") has post-retirement benefits plans for its employees. All of the information pertaining to Syncrude in this note represents the Company's proportionate interest.

The total expense for the defined contribution plans is as follows:

Years ended December 31	2002	2001	2000
EnCana Corporation	$ 14	$ 9	$ 6

Information about defined benefit post-retirement benefit plans in aggregate, is as follows:

	EnCana Corporation		Syncrude
As at December 31	2002	2001	2002
Accrued Benefit Obligation, Beginning of Year	$ 135	$ 115	$ –
Plan acquisition	87	4	122
Current service cost	6	3	4
Interest cost	14	8	6
Benefits paid	(10)	(7)	(3)
Actuarial loss	15	8	–
Contributions	–	–	–
Special termination benefits	3	–	–
Changes as a result of curtailment	1	–	–
Plan amendments	13	4	–
Accrued Benefit Obligation, End of Year	$ 264	$ 135	$ 129

	EnCana Corporation		Syncrude
As at December 31	2002	2001	2002
Fair Value of Plan Assets, Beginning of Year	$ 133	$ 144	$ –
Plan acquisition	83	3	75
Transfers to defined contribution plan	(9)	(9)	–
Actual return on plan assets	(15)	1	(5)
Employer contributions	1	1	3
Employees' contributions	–	–	–
Benefits paid	(8)	(7)	(3)
Fair Value of Plan Assets, End of Year	$ 185	$ 133	$ 70
Funded Status – Plan (Deficit) Surplus	$ (79)	$ (2)	$ (59)
Unamortized Net Actuarial Loss	80	30	45
Unamortized Past Service Cost	16	4	–
Net Transitional (Asset) Liability	(15)	(18)	–
Accrued Benefit Asset (Liability)	$ 2	$ 14	$ (14)

Included in the above accrued benefit obligation and fair value of plan assets at year-end for EnCana Corporation are unfunded benefit obligations of $54 million (2001 – $31 million) related to three of the Company's defined benefit pension plans and the other post retirement benefit plans.

The significant actuarial assumptions used to determine the periodic expense and accrued benefit obligations are as follows:

	EnCana Corporation		Syncrude
Years ended December 31	2002	2001	2002
Discount Rate	**6.5%**	6.5%	**6.5%**
Expected Long-term Rate of Return on Plan Assets	**7.0%**	7.0%	**9.0%**
Rate of Compensation Increase	**3.5%**	4.0%	**4.0%**

The periodic expense for EnCana Corporation employee benefits is as follows:

Years ended December 31	2002	2001	2000
Current Service Cost	**$ 5**	$ 3	$ 2
Interest Cost	**13**	8	7
Expected Return on Plan Assets	**(12)**	(10)	(10)
Amortization of Net Actuarial Gain	**2**	–	–
Amortization of Transitional Obligation	**(3)**	(3)	(2)
Amortization of Past Service Cost	**1**	1	–
Curtailment Loss	**2**	–	–
Special Termination Benefits	**3**	–	–
Expense for Defined Contribution Plan	**14**	9	6
Net Benefit Plan Expense	**$ 25**	$ 8	$ 3

The average remaining service period of the active employees covered by the pension plans is nine years. The average remaining service period of the active employees covered by the other retirement benefit plans is 12 years.

After the business combination transaction as described in Note 3, a number of employees were involuntarily terminated. Terminated members of the defined benefit pension plan, who were age 50 or above, could elect enhanced benefits under the registered pension plan. For pension accounting purposes, this resulted in special termination benefits being provided and a curtailment event that impacted some of the pension arrangements sponsored by the Company.

The periodic expense for Syncrude employee benefits is as follows:

Years ended December 31	2002	2001	2000
Current Service Cost	**$ 4**	$ –	$ –
Interest Cost	**6**	–	–
Expected Return on Plan Assets	**(5)**	–	–
Amortization of Net Actuarial Gain	**1**	–	–
Expense for Defined Contribution Plan	**–**	–	–
Net Benefit Plan Expense	**$ 6**	$ –	$ –

The average remaining service period of the active employees covered by the defined benefit plans is 13 years.

Share Appreciation Rights

The Company has in place a program whereby certain employees are granted Share Appreciation Rights ("SAR's") which entitle the employee to receive a cash payment equal to the excess of the market price of the Company's Common Shares at the time of exercise over the exercise price of the right. In conjunction with the business combination transaction described in Note 3, outstanding AEC SAR's were replaced by EnCana SAR's. SAR's granted expire after five years. The business combination resulted in these replacement SAR's, along with all SAR's previously issued by EnCana, becoming exercisable after the close of business on April 5, 2002.

The following tables summarize the information relating to SAR's:

As at December 31, 2002	Outstanding SAR's	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*		
Outstanding, beginning of year	–	–
Granted	600,000	38.35
Acquired April 5, in AEC acquisition	2,637,421	30.70
Exercised	(648,902)	27.67
Forfeited	(303,618)	39.08
Outstanding, end of year	2,284,901	35.56
Exercisable, end of year	2,284,901	35.56
U.S. Dollar Denominated *(US$)*		
Outstanding, beginning of year	–	–
Acquired April 5, in AEC acquisition	1,711,095	28.32
Exercised	(223,703)	26.33
Forfeited	(140,955)	29.88
Outstanding, end of year	1,346,437	28.52
Exercisable, end of year	1,346,437	28.52

As at December 31, 2002	SAR's Outstanding		
Range of Exercise Price *($)*	Number of SAR's	Weighted Average Remaining Contractual Life *(years)*	Weighted Average Exercise Price *($)*
Canadian Dollar Denominated *(C$)*			
10.00 to 19.99	24,643	0.03	15.63
20.00 to 29.99	966,319	2.04	26.74
30.00 to 39.99	622,080	4.09	38.26
40.00 to 49.99	657,512	3.19	46.38
50.00 to 60.00	14,347	3.32	51.37
	2,284,901	2.92	35.56
U.S. Dollar Denominated *(US$)*			
20.00 to 29.99	688,889	3.11	26.72
30.00 to 40.00	657,548	3.20	30.41
	1,346,437	3.15	28.52

During the year, the Company recorded compensation costs of $7 million related to the outstanding SAR's.

Deferred Share Units

The Company has in place a program whereby Directors and certain key employees are issued Deferred Share Units ("DSU's") which are equivalent in value to a Common Share of the Company. DSU's granted to Directors vest immediately. DSU's granted to Senior Executives in 2002 vest over a three year period.

The following table summarizes the information relating to the DSU's:

As at December 31, 2002	Outstanding DSU's	Average Share Price *($)*
Outstanding, Beginning of Year	–	–
Acquired April 5, in AEC acquisition	29,631	47.29
Granted, Directors	22,500	49.75
Granted, Senior Executives	260,000	49.75
Exercised	(2,964)	48.00
Outstanding, End of Year	309,167	48.69
Exercisable, End of Year	49,167	48.20

During the year, the Company recorded compensation costs of $6 million related to the outstanding DSU's.

NOTE 19 FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Unrecognized gains (losses) on risk management activities are as follows:

As at December 31		2002	2001
Commodity Price Risk	*(Note A)*		
Natural gas		$ 302	$ 145
Crude oil		(122)	12
Gas storage optimization		(43)	–
Natural gas liquids		(3)	–
Power		(3)	–
Foreign Currency Risk	*(Note B)*	(90)	(187)
Interest Rate Risk	*(Note C)*	62	9
		$ 103	$ (21)

A) Commodity Price Risk

Natural Gas

At December 31, 2002, the fair value of financial instruments that related to the corporate gas risk management activities was $51 million. The contracts were as follows:

	Notional Volumes *(MMcf/d)*	Term	Price		Unrecognized Gain/(Loss) *(Cdn$)*
Fixed AECO Price *(Cdn$)*	244	2003	5.89	C$/mcf	$ (37)
Fixed AECO Price *(US$)*	118	2003	3.54	US$/mmbtu	(29)
NYMEX Fixed Price	287	2003	4.10	US$/mmbtu	(78)
Alliance Pipeline Mitigation	42	2003	3.96	US$/mmbtu	(14)
Fixed NYMEX to AECO Basis	181	2003-2007	(0.49)	US$/mmbtu	22
Fixed NYMEX to Rockies Basis	167	2003-2007	(0.47)	US$/mmbtu	187
					$ 51

The unrecognized gain on the physical contracts is $219 million.

The fair value of the financial instruments that related to the gas marketing activities was an unrecognized gain of $9 million. These activities are part of the ongoing operations of the Company's proprietary production management and the financial transactions are directly related to physical sales. The corresponding physical deals have an unrecognized gain of $23 million.

Crude Oil

As at December 31, 2002, the Company's corporate oil risk management activities had an unrecognized loss of $120 million. The contracts were as follows:

	Notional Volumes *(bbl/d)*	Term	Average Price *(US$/bbl)*	Unrecognized Gain/(Loss) *(Cdn$)*
Fixed WTI NYMEX Price	85,000	2003	25.28	$ (81)
Fixed WTI NYMEX Price	62,500	2004	23.13	(10)
Collars on WTI NYMEX	40,000	2003	21.95–29.00	(16)
Collars on WTI NYMEX	62,500	2004	20.00–25.69	(13)
				$ (120)

As at December 31, 2002, the crude oil marketing activities had an unrecognized loss of $2 million on their financial contracts, which were offset by unrecognized gains on physical inventory.

Gas Storage Optimization

As part of the Company's gas storage optimization program, the Company has entered into financial instruments at various locations and terms over the next 13 months to manage the price volatility of the corresponding physical transactions and inventories.

As at December 31, 2002, the unrecognized loss on financial instruments was $40 million, which was as follows:

	Notional Volumes *(bcf)*	Price *(US$/mcf)*	Unrecognized Gain/(Loss) *(Cdn$)*
Purchases	102.4	4.49	$ 64
Sales	115.2	4.33	(104)
			$ (40)

The unrecognized loss on physical contracts was $3 million. The total unrecognized loss of $43 million was more than offset by unrealized gains on physical inventory in storage.

Natural Gas Liquids

Inventory of 315,000 barrels of natural gas liquids has been sold forward at an average price of US$0.47 per U.S. gallon. As at December 31, 2002, the unrecognized loss on these contracts was $1 million.

As at December 31, 2002, the Company had sold call options with strike prices ranging from US$0.36 per U.S. gallon to US$0.50 per U.S. gallon. It also entered into swap contracts that fixed prices at US$0.4075 per U.S. gallon. The total loss of these financial instruments at December 31, 2002 was $2 million, of which approximately $1 million has been recognized.

In addition, the Company had entered into physical contracts that sold forward approximately 562,000 barrels of natural gas liquids at fixed prices ranging from US$0.33 per U.S. gallon to US$0.625 per U.S. gallon and purchased approximately 154,000 barrels of natural gas liquids at fixed prices ranging from US$0.44 per U.S. gallon to US$0.54 per U.S. gallon. The total loss on these contracts at December 31, 2002 was $2 million, of which approximately $1 million has been recognized in the financial results.

Power

As part of the business combination with AEC, the Company acquired two electricity contracts, one expiring in 2003 and the other in 2005. These contracts were originally entered into as part of an electricity cost management strategy. At December 31, 2002, the unrecognized loss on these contracts was $3 million.

B) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Company's operating and financial results. The Company has significant operations outside of Canada, which are subject to these foreign exchange risks.

The following forward foreign currency exchange contracts were in place to hedge future commodity revenue streams as at December 31, 2002:

	Amount Hedged *(US$)*	Average Exchange Rate *(Cdn$/US$)*	Unrecognized Gain/(Loss) *(Cdn$)*
2003	$ 372	0.716	$ (72)
2004	88	0.715	(18)
Total	$ 460	0.716	$ (90)

C) Interest Rate Risk

The Company has entered into various derivative contracts to manage the Company's interest rate exposure on debt instruments. The impact of these transactions is described in Note 7.

The unrecognized gains on the outstanding financial instruments as at December 31, 2002 are:

Debt Instrument	Unrecognized Gain/(Loss) *(Cdn$)*
5.50% Medium Term Notes	$ 2
5.80% Medium Term Notes	11
7.50% Medium Term Notes	10
8.40% Medium Term Notes	13
8.75% Debenture	26
	$ 62

At December 31, 2002, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $26 million (2001 – $5 million).

D) Fair Value of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheet, other than long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments.

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

As at December 31	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	$ 212	$ 212	$ 963	$ 963
Accounts receivable	2,052	2,052	623	623
Financial Liabilities				
Accounts payable, income taxes payable	$ 2,404	$ 2,404	$ 1,480	$ 1,480
Long-term debt	7,607	8,031	2,370	2,237

E) Credit Risk

The Company is exposed to credit related losses in the event of default by counterparties to financial instruments. The Company does not expect any counterparties to these agreements to fail to meet their obligations because of credit practices in place that limit transactions to counterparties of investment grade credit quality. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Company has Board approved credit policies which govern the Company's credit portfolio.

All of the proceeds from the sale of the Company's crude oil production in Ecuador are received from one marketing company. Accounts receivable on these sales are supported by letters of credit issued by a major international financial institution. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

NOTE 20 SUPPLEMENTARY INFORMATION

Per Share Amounts

The following table summarizes the Common Shares used in calculating Net Earnings and Cash Flow per Common Share.

Years ended December 31	2002	2001	2000
Weighted Average Common Shares Outstanding – Basic	417.8	255.6	252.8
Effect of Stock Options and Other Dilutive Securities	7.3	6.2	4.4
Weighted Average Common Shares Outstanding – Diluted	425.1	261.8	257.2

The Net Earnings per Common Share calculations include the effect of the Distributions on Preferred Securities, net of tax, for the year of $3 million (2001 – $4 million; 2000 – $5 million).

Net Change in Non-Cash Working Capital from Continuing Operations

Years ended December 31	2002	2001	2000
Operating Activities			
Accounts receivable and accrued revenue	$ (386)	$ (12)	$ (372)
Inventories	(88)	29	(22)
Accounts payable and accrued liabilities	(5)	86	220
Income taxes payable	(846)	475	176
	$ (1,325)	$ 578	$ 2
Investing Activities			
Accounts payable and accrued liabilities	$ 293	$ 88	$ 42
Financing Activities			
Accounts payable and accrued liabilities	$ (5)	$ 1	$ –

Corporate Reorganization of Canadian Pacific Limited

On February 13, 2001, CPL announced a reorganization whereby its 85% interest in PanCanadian Petroleum Limited (predecessor to PanCanadian Energy Corporation) would be distributed to CPL common shareholders by a Plan of Arrangement. Following shareholder and court approvals, the Plan of Arrangement was implemented on October 1, 2001, and PanCanadian Petroleum Limited became a wholly owned subsidiary of the new public company, PanCanadian Energy Corporation. Effective January 1, 2002, these companies were amalgamated and continued under the name of PanCanadian Energy Corporation.

As part of the CPL reorganization, the Company paid a Special Dividend of $1,180 million ($4.60 per Common Share) on September 14, 2001. For the year ended December 31, 2001, the amounts shown as dividends on the Consolidated Statements of Retained Earnings and Cash Flows include both the Special Dividend and the regular quarterly dividend.

Related Party Transactions

In 2001, the Company paid $50 million relating to a previously contracted purchase price adjustment in respect of $200 million of capital losses acquired in 1997 from a subsidiary of CPL (the majority shareholder of the Company prior to the corporate reorganization as described previously). The purchase price adjustment, which was contingent on certain economic events, was recorded as a charge to retained earnings.

Prior to the previously described corporate reorganization of CPL, the Company purchased materials and utilized services from other companies with which it was affiliated. All such transactions were conducted on an arm's length basis and were not material in relation to the Company's overall activities.

NOTE 21 COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments over the next five years as follows:

	2003	2004	2005	2006	2007	Thereafter	**Total**
Pipeline Transportation	$ 461	$ 479	$ 410	$ 395	$ 387	$ 2,859	**$ 4,991**
Capital Commitments	791	317	62	38	6	61	**1,275**
Office Rental	54	52	51	51	44	237	**489**
Equipment Operating Leases	17	15	159	117	2	47	**357**
Other	40	1	56	51	29	352	**529**
Total	$ 1,363	$ 864	$ 738	$ 652	$ 468	$ 3,556	**$ 7,641**

Legal Proceedings

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

Future Dismantlement and Site Restoration Costs

The Company is responsible for the future dismantlement and site restoration related to its oil and gas properties and Midstream facilities at the end of their useful lives. The Company currently estimates the total amount of this future liability to be approximately $1,405 million, of which $494 million has been accrued based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Equipment Operating Leases

Between 1997 and 2001, the Company entered into lease arrangements for field equipment, natural gas storage equipment and aircraft. These leases were arranged through variable interest entities sponsored by various financial institutions. At the inception of the leases, the value of the equipment was $370 million. These variable interest entities are not consolidated in the Company's financial statements and the Company has accounted for these arrangements as operating leases in accordance with Canadian generally accepted accounting principles.

The leases are at normal commercial terms and expire between 2005 and 2008 with no renewal options. Future minimum lease payments related to these leases are included in the table above. The agreements for these leases contain various covenants including covenants regarding the Company's financial condition. Default under a lease, including violation of these covenants, could require the Company to purchase the leased equipment or aircraft for a specified amount, which approximates the lessor's original cost. As of December 31, 2002, the Company was in compliance with these covenants.

The Company has the option to purchase this leased equipment and aircraft in the year 2003 or to assist the variable interest entities in the sale of the assets at the end of the lease. The Company has provided a residual guarantee value for any deficiency if the equipment or aircraft are sold for less than the sale option amount. These amounts, if any, are not currently expected to have a material impact on the financial position or the results of operations of the Company.

The Financial Accounting Standards Board in the United States has issued FASB Interpretation 46 "Consolidation of Variable Interest Entities" effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that their primary beneficiary consolidate certain variable interest entities. As a result, the equipment operating leases will be consolidated under the new standard, as written.

NOTE 22 SUBSEQUENT EVENTS

Amalgamation with Alberta Energy Company Ltd.

On January 2, 2003, the Company announced that it had completed its vertical short-form amalgamation with its wholly owned subsidiary AEC effective January 1, 2003. EnCana Corporation is now the successor issuer in respect of AEC's previously issued debt securities, including the Preferred Securities, and will be responsible for all AEC's contractual obligations.

Sale of Interests in Cold Lake and Express Pipeline Systems

On January 2, 2003 and January 9, 2003 the Company announced that it had completed its previously announced sales of its interests in the Cold Lake and Express Pipeline Systems for estimated total proceeds of approximately $1.6 billion, including assumption of related long-term debt. Both sales are subject to closing and post-closing adjustments.

Sale of Interest in Syncrude Joint Venture

On February 3, 2003, the Company announced it had reached agreement with Canadian Oil Sands Limited to sell a 10 percent interest in the Syncrude Joint Venture for approximately $1.07 billion. The Company has also granted Canadian Oil Sands Limited an option, which expires December 31, 2003, to purchase its remaining 3.75% interest in Syncrude and an overriding royalty. If exercised, the option would generate approximately $417 million in additional proceeds.

NOTE 23 UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

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

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

Years ended December 31		2002	2001	2000
Net Earnings from Continuing Operations – Canadian GAAP		$ 1,225	$ 1,254	$ 1,000
Increase (Decrease) under U.S. GAAP				
Depreciation, depletion and amortization	*(Note A)*	19	5	8
Additional depletion	*(Note A)*	–	(145)	–
Interest expense, net	*(Note B)*	(32)	(4)	(5)
Distributions on Preferred Securities of Subsidiary	*(Note B)*	20	–	–
Change in fair value of financial instruments	*(Note C)*	(79)	141	(60)
Stock-based compensation	*(Note D)*	(5)	(15)	–
Employee future benefits	*(Note E)*	–	–	1
Income taxes	*(Note G)*	37	(6)	(52)
Net Earnings from Continuing Operations – U.S. GAAP		1,185	1,230	892
Net (Loss) Earnings from Discontinued Operations – U.S. GAAP		(1)	33	21
Net Earnings – U.S. GAAP		$ 1,184	$ 1,263	$ 913
Net Earnings per Common Share – U.S. GAAP				
Basic		$ 2.83	$ 4.94	$ 3.61
Diluted		$ 2.79	$ 4.82	$ 3.55

Consolidated Statement of Earnings – U.S. GAAP

Years ended December 31		2002	2001	2000
Revenues, Net of Royalties and Production Taxes		$ 10,011	$ 4,894	$ 4,366
Expenses				
Transportation and selling		574	172	148
Operating		1,438	693	620
Purchased product		3,448	1,144	1,019
Administrative	*(Notes D, E)*	192	98	67
Interest, net	*(Note B)*	451	49	74
Foreign exchange (gain) loss		(20)	20	37
Depreciation, depletion and amortization	*(Note A)*	2,134	992	764
Loss (gain) on derivatives	*(Note C)*	79	(108)	60
Loss (gain) on derivatives – adoption of SFAS 133	*(Note C)*	–	(33)	–
Gain on corporate disposition		(51)	–	–
Net Earnings Before the Undernoted		1,766	1,867	1,577
Income tax expense	*(Note G)*	581	637	685
Net Earnings from Continuing Operations – U.S. GAAP		1,185	1,230	892
Net (Loss) Earnings from Discontinued Operations – U.S. GAAP		(1)	33	21
Net Earnings – U.S. GAAP		$ 1,184	$ 1,263	$ 913
Net Earnings from Continuing Operations per Common Share – U.S. GAAP				
Basic		$ 2.84	$ 4.81	$ 3.53
Diluted		$ 2.79	$ 4.70	$ 3.47
Net Earnings per Common Share – U.S. GAAP				
Basic		$ 2.83	$ 4.94	$ 3.61
Diluted		$ 2.79	$ 4.82	$ 3.55

Condensed Consolidated Balance Sheet

As at December 31		2002		2001	
		As Reported	U.S. GAAP	As Reported	U.S. GAAP
Assets					
Current assets		$ 4,289	$ 4,289	$ 1,673	$ 1,674
Financial assets	*(Note C)*	–	286	–	217
Capital assets, net	*(Note A)*	23,770	23,589	8,162	7,962
Investments and other assets	*(Note B)*	377	388	237	241
Assets of discontinued operations		–	–	728	728
Goodwill		2,886	2,886	–	–
		$ 31,322	$ 31,438	$ 10,800	$ 10,822
Liabilities and Shareholders' Equity					
Current liabilities		$ 3,879	$ 3,879	$ 1,640	$ 1,643
Financial liabilities	*(Note C)*	–	412	–	257
Long-term debt	*(Note B)*	7,395	7,978	2,210	2,336
Deferred credits and other liabilities	*(Note B)*	585	592	325	312
Future income taxes	*(Note G)*	5,212	5,091	2,060	1,970
Liabilities of discontinued operations		–	–	586	586
Preferred securities of subsidiary	*(Note B)*	457	–	–	–
		17,528	17,952	6,821	7,104
Preferred securities	*(Note B)*	126	–	126	–
Share capital	*(Note D)*	8,732	8,752	196	211
Share options, net		133	133	–	–
Paid in surplus		61	61	27	27
Retained earnings		4,684	4,503	3,630	3,486
Foreign currency translation adjustment	*(Note F)*	58	–	–	–
Accumulated other comprehensive income	*(Note F)*	–	37	–	(6)
		13,794	13,486	3,979	3,718
		$ 31,322	$ 31,438	$ 10,800	$ 10,822

Statement of Other Comprehensive Income

Years ended December 31		2002	2001	2000
Net Earnings – U.S. GAAP		$ 1,184	$ 1,263	$ 913
Adoption of SFAS 133, net of tax	*(Notes C, H)*	–	(79)	–
Change in Fair Value of Financial Instruments	*(Note H)*	(11)	73	–
Foreign Currency Translation Adjustment	*(Note F)*	58	–	–
Other		(10)	–	–
Other Comprehensive Income		$ 1,221	$ 1,257	$ 913

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

Years ended December 31	2002	2001	2000
Cash From Operating Activities			
Net earnings from continuing operations	$ 1,185	$ 1,230	$ 892
Depreciation, depletion and amortization	2,134	992	764
Future income taxes	630	140	522
Other	(173)	(107)	95
Cash flow from continuing operations	3,776	2,255	2,273
Cash flow from discontinued operations	42	47	25
Cash flow	3,818	2,302	2,298
Net change in other assets and liabilities	(22)	(63)	(74)
Net change in non-cash working capital from continuing operations	(1,325)	578	2
Net change in non-cash working capital from discontinued operations	97	(47)	(2)
	$ 2,568	$ 2,770	$ 2,224
Cash Used in Investing Activities	$ (4,062)	$ (1,697)	$ (2,321)
Cash From Financing Activities	$ 750	$ (326)	$ 163

A) Full Cost Accounting

The full cost method of accounting for conventional oil and natural gas operations under Canadian and U.S. GAAP differ in the following respect. Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum of the present value, discounted at 10 percent, of the estimated unescalated future net operating revenue from proved reserves plus unimpaired unproved property costs less future development costs, related production, site restoration and applicable taxes. Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that future revenues are undiscounted and administrative and interest expenses are deducted from revenues.

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

B) Preferred Securities

Under U.S. GAAP, preferred securities are classified as long-term debt and any distributions paid on these securities are treated as interest expense. Issue costs are capitalized and amortized to earnings over the term of the security. Under Canadian GAAP, preferred securities are classified as equity and any distributions paid, net of applicable income taxes, are recorded as a direct charge to retained earnings.

C) Derivative Instruments and Hedging

Prior to 2001, U.S. GAAP required fair value recognition in the financial statements with respect to forward foreign currency exchange contracts associated with anticipated future transactions that do not constitute firm commitments. Gains or losses arising from changes in the market value were immediately reflected in earnings. Under Canadian GAAP, the Company's forward foreign exchange contracts qualify as hedges for accounting purposes. Payments or receipts on these contracts are recognized in earnings concurrently with the hedged transaction and the fair values of the outstanding contracts are not reflected in the Consolidated Financial Statements.

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

The adoption of SFAS 133 at January 1, 2001 resulted in recognition of derivative assets with a fair value of $858 million, derivative liabilities with a fair value of $942 million, a $117 million ($79 million, net of tax) charge to other comprehensive income and a $33 million ($23 million, net of tax) increase to net earnings under U.S. GAAP.

As at December 31, 2002, it is estimated that over the following 12 months, $4 million ($2 million, net of tax) will be reclassified into earnings from other comprehensive income.

D) Stock-based Compensation

The Company accounts for its stock-based compensation using the intrinsic value method. Under Canadian GAAP, no compensation costs have been recognized in the financial statements for share options granted to employees and directors. Under Financial Accounting Standards Board ("FASB") Interpretation No. 44 "Accounting for Certain Transactions involving Stock Compensation", compensation expense must be recorded if the intrinsic value of the stock options is not exactly the same immediately before and after an equity restructuring. For the effect of stock-based compensation on the Canadian GAAP financials, which would be the same adjustment under U.S. GAAP, see Note 17.

As part of the Corporate reorganization, as described in Note 20, an equity restructuring occurred which resulted in CPL stock options being replaced with stock options granted by PanCanadian as described in Note 17. This resulted in the replacement options having a different intrinsic value after the restructuring than prior to the restructuring. Canadian GAAP does not require revaluation of these options.

E) Employee Future Benefits

Prior to 2000, there was a difference between Canadian and U.S. GAAP in accounting for pension and other post-employment benefits.

Under U.S. GAAP, the discount rate used for computing the benefit obligation and the service and interest cost components of the net periodic pension expense is the rate at which the pension benefits could be currently settled. Prior to 2000, the Canadian GAAP discount rate was based on Management's best estimate of the future return on the plan assets.

Prior to 2000, the Company recognized the cost of providing other post-employment benefits as they were paid. U.S. GAAP requires these costs to be recognized on an accrual basis during the service period of the employees.

Effective January 1, 2000, the Company prospectively adopted the new Canadian accounting standard for Employee Future Benefits eliminating any significant differences between Canadian and U.S. GAAP in accounting for pension costs and other post-employment benefits.

F) Foreign Currency Translation Adjustments

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

G) Future Income Taxes

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

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

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

Years ended December 31	2002	2001	2000
Using Canadian GAAP			
Net earnings before income taxes	$ 1,863	$ 1,885	$ 1,633
Canadian Statutory Rate	42.3%	42.8%	44.7%
Expected Income Taxes	$ 788	$ 807	$ 730
Effect on Taxes Resulting from:			
Non-deductible Canadian crown payments	232	113	104
Canadian resource allowance	(331)	(258)	(245)
Large corporations tax	35	16	16
Statutory rate differences	(57)	(19)	9
Effect of tax rate reductions	(33)	(81)	–
Other	(16)	53	19
	618	631	633
U.S. GAAP Adjustments to Net Earnings Before Income Taxes	(97)	(18)	(56)
Expected Income Taxes	(41)	(8)	(25)
Depletion	–	3	4
FAS 109 Implementation Adjustments	–	–	74
Other	4	11	(1)
	(37)	6	52
Income Taxes – U.S. GAAP	$ 581	$ 637	$ 685
Effective Tax Rate	32.9%	34.1%	43.4%

The net deferred income tax liability is comprised of:

As at December 31	2002	2001
Future Tax Assets		
Capital assets in excess of tax values	$ 4,708	$ 1,813
Timing of partnership items	809	292
Future Tax Liabilities		
Net operating losses carried forward	(320)	(135)
Other	(106)	–
Net Future Income Tax Liability	$ 5,091	$ 1,970

H) Other Comprehensive Income

U.S. GAAP requires the disclosure, as other comprehensive income, of changes in equity during the period from transaction and other events from non-owner sources. Canadian GAAP does not require similar disclosure. Other comprehensive income arose from the transition adjustment resulting from the January 1, 2001 adoption of SFAS 133. At December 31, 2002, accumulated other comprehensive income, related to these items, was a loss of $11 million, net of tax.

I) Recent Accounting Pronouncements

During 2002, the following new or amended standards and guidelines were issued:

Asset Retirement Obligations

FASB issued SFAS No.143 "Accounting for Asset Retirement Obligations", effective for years beginning after June 15, 2002. The standard requires legal obligations associated with the retirement of long-lived tangible assets be recognized at fair value. The Canadian Institute of Chartered Accountants issued an exposure draft, "Asset Retirement Obligations", which would harmonize Canadian GAAP with SFAS No. 143 "Accounting for Asset Retirement Obligations". The Canadian standard will be effective for fiscal years beginning on or after January 1, 2004. The Company is evaluating the impact of these new standards.

Hedging Relationships

The CICA issued Accounting Guideline 13 "Hedging Relationships" which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003. The effect of adopting the guideline on the Company's Consolidated Financial Statements has not been determined at this time.

Consolidation of Variable Interest Entities

FASB issued FASB Interpretation 46 "Consolidation of Variable Interest Entities" effective for the first interim or annual reporting period beginning after June 14, 2003. The standard mandates that certain variable interest entities be consolidated by their primary beneficiary. At December 31, 2002, the Company has several operating leases that may be consolidated under the new standard. Refer to Note 21.

Stock-Based Compensation and Other Stock-Based Payments

In December 2002, the CICA issued an exposure draft for "Stock-Based Compensation and Other Stock-Based Payments". The new standard proposes to eliminate the option for an enterprise to disclose pro forma earnings and pro forma earnings per share as if the fair value based method of accounting had been applied. This would require the recognition of stock-based compensation expense for all stock-based compensation transactions.

Costs Associated with Exit or Disposal Activities

In June 2002, FASB issued SFAS 146 "Accounting for Costs Associated with Exit or Disposal Activities". The standard requires that liabilities for exit or disposal activity costs be recognized and measured at fair value when the liability is incurred. This standard is effective for disposal activities initiated after December 31, 2002.

The following unaudited disclosures on standardized measures of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities".

SUPPLEMENTARY OIL AND GAS INFORMATION

(unaudited)

The following unaudited supplementary oil and gas information is provided in accordance with the United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities".

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following disclosures on standardized measures of discounted cash flows and changes therein relating to proved oil and gas reserves are determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities".

In calculating the standardized measure of discounted future net cash flows, year end constant prices and cost assumptions were applied to the Company's annual future production from proved reserves to determine cash inflows. Future development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying the year end statutory rate to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows.

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

SUPPLEMENTARY OIL AND GAS INFORMATION

(unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (EXCLUDING SYNCRUDE)

Net Proved Reserves (Company Share After Royalties)

	Natural Gas *(billions of cubic feet)*				Crude Oil and Natural Gas Liquids *(millions of barrels)*											
					Canada			United States			Ecuador	United Kingdom			Aus-tralia	
	Canada	United States	United King-dom	**Total**	Oil	NGLs	**Total**	Oil	NGLs	**Total**	Oil	Oil	NGLs	**Total**	Oil	**Total**
2000																
Beginning of year	2,882	–	–	**2,882**	334.4	25.6	**360.0**	–	–	**–**	–	–	–	**–**	5.0	**365.0**
Revisions and improved recovery	209	–	6	**215**	8.3	1.0	**9.3**	–	–	**–**	–	5.2	1.3	**6.5**	–	**15.8**
Extensions and discoveries	446	–	–	**446**	19.8	2.1	**21.9**	–	–	**–**	–	–	–	**–**	–	**21.9**
Purchase of reserves in place	143	211	7	**361**	0.4	0.6	**1.0**	5.2	11.5	**16.7**	–	21.8	–	**21.8**	–	**39.5**
Sale of reserves in place	(3)	–	–	**(3)**	(8.8)	(0.1)	**(8.9)**	–	–	**–**	–	–	–	**–**	–	**(8.9)**
Sales	(327)	(3)	(3)	**(333)**	(31.2)	(4.1)	**(35.3)**	–	–	**–**	–	(4.3)	(0.3)	**(4.6)**	–	**(39.9)**
End of year	3,350	208	10	**3,568**	322.9	25.1	**348.0**	5.2	11.5	**16.7**	–	22.7	1.0	**23.7**	5.0	**393.4**
Developed	2,763	146	10	**2,919**	240.7	23.5	**264.2**	4.3	7.8	**12.1**	–	22.7	1.0	**23.7**	–	**300.0**
Undeveloped	587	62	–	**649**	82.2	1.6	**83.8**	0.9	3.7	**4.6**	–	–	–	**–**	5.0	**93.4**
Total	3,350	208	10	**3,568**	322.9	25.1	**348.0**	5.2	11.5	**16.7**	–	22.7	1.0	**23.7**	5.0	**393.4**
2001																
Beginning of year	3,350	208	10	**3,568**	322.9	25.1	**348.0**	5.2	11.5	**16.7**	–	22.7	1.0	**23.7**	5.0	**393.4**
Revisions and improved recovery	59	6	–	**65**	1.5	3.5	**5.0**	0.1	1.5	**1.6**	–	1.9	0.2	**2.1**	–	**8.7**
Extensions and discoveries	448	13	–	**461**	12.4	2.6	**15.0**	–	2.0	**2.0**	–	–	–	**–**	–	**17.0**
Purchase of reserves in place	1	25	–	**26**	–	–	**–**	–	–	**–**	–	–	–	**–**	–	**–**
Sale of reserves in place	(1)	–	–	**(1)**	(48.0)	–	**(48.0)**	–	–	**–**	–	–	–	**–**	(5.0)	**(53.0)**
Sales	(353)	(16)	(3)	**(372)**	(29.9)	(3.5)	**(33.4)**	(0.4)	(0.3)	**(0.7)**	–	(4.0)	(0.2)	**(4.2)**	–	**(38.3)**
End of year	3,504	236	7	**3,747**	258.9	27.7	**286.6**	4.9	14.7	**19.6**	–	20.6	1.0	**21.6**	–	**327.8**
Developed	2,908	172	7	**3,087**	219.0	26.3	**245.3**	4.8	10.1	**14.9**	–	20.6	1.0	**21.6**	–	**281.8**
Undeveloped	596	64	–	**660**	39.9	1.4	**41.3**	0.1	4.6	**4.7**	–	–	–	**–**	–	**46.0**
Total	3,504	236	7	**3,747**	258.9	27.7	**286.6**	4.9	14.7	**19.6**	–	20.6	1.0	**21.6**	–	**327.8**
2002																
Beginning of year	3,504	236	7	**3,747**	258.9	27.7	**286.6**	4.9	14.7	**19.6**	–	20.6	1.0	**21.6**	–	**327.8**
Purchase of AEC reserves in place	2,686	944	–	**3,630**	222.8	10.9	**233.7**	–	6.5	**6.5**	168.4	–	–	**–**	–	**408.6**
Revisions and improved recovery	(1,140)	731	7	**(402)**	(5.6)	(9.9)	**(15.5)**	16.5	(11.9)	**4.6**	(33.5)	(9.4)	0.3	**(9.1)**	–	**(53.5)**
Extensions and discoveries	726	319	10	**1,055**	92.5	4.4	**96.9**	2.8	0.5	**3.3**	31.1	88.0	1.2	**89.2**	–	**220.5**
Purchase of reserves in place	30	530	–	**560**	4.8	0.1	**4.9**	3.8	6.1	**9.9**	–	–	–	**–**	–	**14.8**
Sale of reserves in place	(129)	(73)	–	**(202)**	(17.0)	(1.2)	**(18.2)**	(0.7)	–	**(0.7)**	–	–	–	**–**	–	**(18.9)**
Sales	(604)	(114)	(4)	**(722)**	(41.4)	(5.1)	**(46.5)**	(0.1)	(2.2)	**(2.3)**	(10.2)	(3.8)	(0.3)	**(4.1)**	–	**(63.1)**
End of year	5,073	2,573	20	**7,666**	515.0	26.9	**541.9**	27.2	13.7	**40.9**	155.8	95.4	2.2	**97.6**	–	**836.2**
Developed	4,139	1,446	9	**5,594**	274.7	24.5	**299.2**	13.5	8.4	**21.9**	104.6	7.4	0.9	**8.3**	–	**434.0**
Undeveloped	934	1,127	11	**2,072**	240.3	2.4	**242.7**	13.7	5.3	**19.0**	51.2	88.0	1.3	**89.3**	–	**402.2**
Total	5,073	2,573	20	**7,666**	515.0	26.9	**541.9**	27.2	13.7	**40.9**	155.8	95.4	2.2	**97.6**	–	**836.2**

SUPPLEMENTARY OIL AND GAS INFORMATION

(unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (EXCLUDING SYNCRUDE)

Results of Operations

($ millions)	Canada			United States			Ecuador		
Years ended December 31	2002	2001	2000	2002	2001	2000	2002	2001	2000
Oil and gas revenues, net of royalties and production taxes, transportation and selling costs	$ 4,015	$ 3,050	$ 2,672	$ 582	$ 79	$ 18	$ 327	$ –	$ –
Operating costs	724	412	343	64	17	2	83	–	–
Depreciation, depletion and amortization	1,447	651	607	333	52	14	131	–	–
Operating income (loss)	1,844	1,987	1,722	185	10	2	113	–	–
Income taxes	682	635	532	70	4	–	41	–	–
Results of operations	$ 1,162	$ 1,352	$ 1,190	$ 115	$ 6	$ 2	$ 72	$ –	$ –

($ millions)	United Kingdom			Other			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Oil and gas revenues, net of royalties and production taxes, transportation and selling costs	$ 141	$ 152	$ 145	$ –	$ –	$ –	$ 5,065	$ 3,281	$ 2,835
Operating costs	18	17	23	34	–	–	923	446	368
Depreciation, depletion and amortization	65	68	104	32	28	–	2,008	799	725
Operating income (loss)	58	67	18	(66)	(28)	–	2,134	2,036	1,742
Income taxes	23	24	15	–	(11)	–	816	652	547
Results of operations	$ 35	$ 43	$ 3	$ (66)	$ (17)	$ –	$ 1,318	$ 1,384	$ 1,195

Capitalized Costs

($ millions)	Canada			United States			Ecuador		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Proved oil and gas properties	$ 20,233	$ 12,136	$ 11,248	$ 3,994	$ 756	$ 446	$ 1,446	$ –	$ –
Unproved oil and gas properties	1,758	324	178	917	185	170	212	–	–
Total capital cost	21,991	12,460	11,426	4,911	941	616	1,658	–	–
Accumulated DD&A	7,435	6,130	5,574	409	46	10	115	–	–
Net capitalized costs	$ 14,556	$ 6,330	$ 5,852	$ 4,502	$ 895	$ 606	$ 1,543	$ –	$ –

($ millions)	United Kingdom			Other			Total		
	2002	2001	2000	2002	2001	2000	2002	2001	2000
Proved oil and gas properties	$ 615	$ 446	$ 406	$ –	$ –	$ 26	$ 26,288	$ 13,338	$ 12,126
Unproved oil and gas properties	80	70	38	357	228	210	3,324	807	596
Total capital cost	695	516	444	357	228	236	29,612	14,145	12,722
Accumulated DD&A	208	136	75	155	146	160	8,322	6,458	5,819
Net capitalized costs	$ 487	$ 380	$ 369	$ 202	$ 82	$ 76	$ 21,290	$ 7,687	$ 6,903

SUPPLEMENTARY OIL AND GAS INFORMATION

(unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (EXCLUDING SYNCRUDE)

Costs Incurred

($ millions)	Canada			United States			Ecuador		
Years ended December 31	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Acquisitions									
– AEC unproved reserves	**$ 2,345**	$ –	$ –	**$ 691**	$ –	$ –	**$ 348**	$ –	$ –
– other unproved reserves	**19**	6	113	**314**	20	302	**–**	–	–
– AEC proved reserves	**5,486**	–	–	**1,580**	–	–	**1,065**	–	–
– other proved reserves	**123**	2	47	**711**	53	211	**–**	–	–
Total acquisitions	**7,973**	8	160	**3,296**	73	513	**1,413**	–	–
Exploration costs	**632**	471	449	**352**	199	61	**55**	–	–
Development	**1,401**	889	721	**439**	11	–	**210**	–	–
Total costs incurred	**$ 10,006**	$ 1,368	$ 1,330	**$ 4,087**	$ 283	$ 574	**$ 1,678**	$ –	$ –

($ millions)	United Kingdom			Other			Total		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Acquisitions									
– AEC unproved reserves	**$ –**	$ –	$ –	**$ –**	$ –	$ –	**$ 3,384**	$ –	$ –
– other unproved reserves	**–**	–	284	**–**	–	–	**333**	26	699
– AEC proved reserves	**–**	–	–	**–**	–	–	**8,131**	–	–
– other proved reserves	**–**	–	–	**–**	6	–	**834**	61	258
Total acquisitions	**–**	–	284	**–**	6	–	**12,682**	87	957
Exploration costs	**26**	38	9	**186**	64	41	**1,251**	772	560
Development	**104**	27	23	**–**	–	–	**2,154**	927	744
Total costs incurred	**$ 130**	$ 65	$ 316	**$ 186**	$ 70	$ 41	**$ 16,087**	$ 1,786	$ 2,261

Discounted Future Net Cash Flows Related to Proved Oil and Gas Reserves

($ millions)	Canada			United States			Ecuador		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Future cash flows	**$ 47,214**	$ 17,149	$ 38,544	**$ 13,481**	$ 1,346	$ 964	**$ 5,319**	$ –	$ –
Future production and development costs	**13,720**	4,889	6,640	**3,943**	454	316	**1,434**	–	–
Undiscounted pre-tax cash flows	**33,494**	12,260	31,904	**9,538**	892	648	**3,885**	–	–
Future income taxes	**10,035**	4,147	11,122	**2,376**	39	219	**923**	–	–
Future net cash flows	**23,459**	8,113	20,782	**7,162**	853	429	**2,962**	–	–
Less discount of net cash flows using a 10% rate	**9,506**	3,240	9,015	**3,764**	376	211	**975**	–	–
Discounted future net cash flows	**$ 13,953**	$ 4,873	$ 11,767	**$ 3,398**	$ 477	$ 218	**$ 1,987**	$ –	$ –

($ millions)	United Kingdom			Other			Total		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Future cash flows	**$ 4,051**	$ 660	$ 718	**$ –**	$ –	$ 185	**$ 70,065**	$ 19,155	$ 40,411
Future production and development costs	**1,948**	257	214	**–**	–	64	**21,045**	5,600	7,234
Undiscounted pre-tax cash flows	**2,103**	403	504	**–**	–	121	**49,020**	13,555	33,177
Future income taxes	**763**	85	152	**–**	–	35	**14,097**	4,271	11,528
Future net cash flows	**1,340**	318	352	**–**	–	86	**34,923**	9,284	21,649
Less discount of net cash flows using a 10% rate	**692**	96	132	**–**	–	13	**14,937**	3,712	9,371
Discounted future net cash flows	**$ 648**	$ 222	$ 220	**$ –**	$ –	$ 73	**$ 19,986**	$ 5,572	$ 12,278

SUPPLEMENTARY OIL AND GAS INFORMATION

(unaudited)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (EXCLUDING SYNCRUDE)

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

($ millions)	Canada			United States			Ecuador		
Years ended December 31	**2002**	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Balance, beginning of year	**$ 4,873**	$ 11,767	$ 5,874	**$ 477**	$ 218	$ –	**$ –**	$ –	$ –
Changes resulting from:									
Sales of oil and gas produced during the period	**(3,291)**	(2,638)	(2,329)	**(518)**	(62)	(16)	**(244)**	–	–
Discoveries and extensions net of related costs	**2,042**	776	1,912	**463**	58	–	**521**	–	–
Purchases of proved AEC reserves in place	**10,757**	–	–	**1,649**	–	–	**2,890**	–	–
Purchases of proved reserves in place	**147**	6	562	**968**	48	401	**–**	–	–
Sales of proved reserves in place	**(586)**	(373)	(105)	**(114)**	–	–	**–**	–	–
Net change in prices and production costs	**5,088**	(10,793)	7,272	**308**	172	–	**–**	–	–
Revisions to quantity estimates	**(2,124)**	143	919	**1,053**	19	–	**(561)**	–	–
Accretion of discount	**724**	1,795	863	**89**	32	–	**–**	–	–
Changes in future development costs	**154**	257	136	**85**	(110)	(58)	**–**	–	–
Other	**(102)**	31	56	**(80)**	–	–	**–**	–	–
Net change in income taxes	**(3,729)**	3,902	(3,393)	**(982)**	102	(109)	**(619)**	–	–
Balance, end of year	**$ 13,953**	$ 4,873	$ 11,767	**$ 3,398**	$ 477	$ 218	**$ 1,987**	$ –	$ –

($ millions)	United Kingdom			Other			Total		
	2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
Balance, beginning of year	**$ 222**	$ 220	$ –	**$ –**	$ 73	$ 72	**$ 5,572**	$ 12,278	$ 5,946
Changes resulting from:									
Sales of oil and gas produced during the period	**(123)**	(135)	(122)	**–**	–	–	**(4,176)**	(2,835)	(2,467)
Discoveries and extensions net of related costs	**938**	–	–	**–**	–	–	**3,964**	834	1,912
Purchases of proved AEC reserves in place	**–**	–	–	**–**	–	–	**15,296**	–	–
Purchases of proved reserves in place	**–**	–	394	**–**	–	–	**1,115**	54	1,357
Sales of proved reserves in place	**–**	–	–	**–**	(73)	–	**(700)**	(446)	(105)
Net change in prices and production costs	**(1)**	22	–	**–**	–	(3)	**5,395**	(10,599)	7,269
Revisions to quantity estimates	**(84)**	30	131	**–**	–	–	**(1,716)**	192	1,050
Accretion of discount	**22**	48	–	**–**	–	10	**835**	1,875	873
Changes in future development costs	**4**	(8)	(11)	**–**	–	(1)	**243**	139	66
Other	**(12)**	–	–	**–**	–	–	**(194)**	31	56
Net change in income taxes	**(318)**	45	(172)	**–**	–	(5)	**(5,648)**	4,049	(3,679)
Balance, end of year	**$ 648**	$ 222	$ 220	**$ –**	$ –	$ 73	**$ 19,986**	$ 5,572	$ 12,278

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited)

Pro forma
Consolidated Statement of Earnings

($ millions, except per share amounts)	EnCana Year Ended December 31, 2002	AEC 3 Months Ended March 31, 2002	Pro forma Adjustments Note 1	**EnCana Pro forma Consolidated**
Revenues, Net of Royalties and Production Taxes				
Upstream	$ 5,864	$ 844	$ (141)	**$ 6,567**
Midstream & Marketing	4,133	358	141	**4,632**
Other	14	–	–	**14**
	10,011	1,202	–	**11,213**
Expenses				
Transportation and selling	574	103	–	**677**
Operating	1,438	202	–	**1,640**
Purchased product	3,448	406	–	**3,854**
Administrative	187	24	–	**211**
Interest, net	419	61	9	**489**
Foreign exchange (gain)	(20)	(1)	–	**(21)**
Depreciation, depletion and amortization	2,153	302	45	**2,500**
Gain on corporate disposition	(51)	–	–	**(51)**
Net Earnings Before the Undernoted	1,863	105	(54)	**1,914**
Income tax expense (recovery)	618	39	(23)	**634**
Distributions on Subsidiary Preferred Securities, net of tax	20	16	(5)	**31**
Net Earnings from Continuing Operations	1,225	50	(26)	**1,249**
Net Earnings from Discontinued Operations	(1)	6	–	**5**
Net Earnings	1,224	56	(26)	**1,254**
Distributions on preferred securities, net of tax	3	–	–	**3**
Net Earnings Attributable to Common Shareholders	$ 1,221	$ 56	$ (26)	**$ 1,251**
Net Earnings from Continuing Operations per Common Share				
Basic				**$ 2.63**
Diluted				**$ 2.58**
Net Earnings per Common Share				
Basic				**$ 2.64**
Diluted				**$ 2.59**

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited)

Pro forma Consolidated Statement of Cash Flow

($ millions, except per share amounts)	EnCana Year Ended December 31, 2002	AEC 3 Months Ended March 31, 2002	Pro forma Adjustments Note 1	**EnCana Pro forma Consolidated**
Operating Activities				
Net earnings from continuing operations	$ 1,225	$ 50	$ (26)	**$ 1,249**
Depreciation, depletion and amortization	2,153	302	45	**2,500**
Future income taxes	667	13	(19)	**661**
Other	(266)	9	–	**(257)**
Cash Flow from Continuing Operations	3,779	374	–	**4,153**
Cash Flow from Discontinued Operations	42	16	–	**58**
Cash Flow	$ 3,821	$ 390	$ –	**$ 4,211**
Cash Flow from Continuing Operations per Common Share				
Basic				**$ 8.77**
Diluted				**$ 8.59**
Cash Flow per Common Share				
Basic				**$ 8.89**
Diluted				**$ 8.71**

NOTES TO PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

(unaudited) December 31, 2002

NOTE 1 BASIS OF PRESENTATION

The unaudited Pro forma Consolidated Statement of Earnings and Consolidated Statement of Cash Flow have been prepared for information purposes using information contained in the following:

(a) EnCana's audited Consolidated Financial Statements for the year ended December 31, 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 December 31, 2002 audited Consolidated Financial Statements of EnCana and assume that the transaction occurred on January 1, 2002.

Pro forma adjustments made in the unaudited Pro forma Consolidated Statement of Earnings and unaudited Pro forma Consolidated Statement of Cash Flow 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.

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited) For the year ended December 31, 2002

Financial Statistics

(C$ millions, except per share amounts)	Pro forma	2002		
	Year	Q4	Q3	Q2
Earnings, excluding foreign exchange				
translation of U.S. dollar debt (after tax)*	$ 1,227	$ 419	$ 349	$ 295
Per share – Diluted	2.53	0.86	0.72	0.63
Net Earnings from Continuing Operations	1,249	416	184	494
Per share – Basic	2.63	0.87	0.38	1.07
– Diluted	2.58	0.86	0.38	1.05
Net Earnings	1,254	429	204	458
Per share – Basic	2.64	0.90	0.43	0.99
– Diluted	2.59	0.88	0.42	0.97
Cash Flow from Continuing Operations	4,153	1,449	1,027	916
Per share – Basic	8.77	3.03	2.15	1.99
– Diluted	8.59	2.99	2.13	1.95
Cash Flow	4,211	1,472	1,022	938
Per share – Basic	8.89	3.08	2.14	2.03
– Diluted	8.71	3.03	2.12	2.00

Shares	Pro forma	2002		
	Year	Q4	Q3	Q2
Common shares outstanding *(millions)*				
Average	473.8	477.9	476.8	461.1
Average Diluted	483.6	485.2	482.2	470.0
Price range *($ per share)*				
TSX – C$				
High	50.25	49.75	48.25	50.25
Low	37.60	41.75	38.05	43.62
Close	48.78	48.78	48.00	46.70
NYSE – US$				
High	32.20	32.10	31.35	32.20
Low	23.54	26.45	24.08	28.50
Close	31.10	31.10	30.10	30.60
Share volume traded *(millions)*	442.5	122.3	105.5	113.2
Share value traded *($ millions weekly average)*	385.6	418.3	366.3	412.6

Ratios	
Debt to Capitalization	36%
Return on Capital Employed (2002 – Pro forma)	7.6%
Return on Common Equity (2002 – Pro forma)	9.2%

* The Company is required to translate long-term debt denominated in U.S. dollars into Canadian dollars at the period-end exchange rate with any resulting adjustments recorded in the Consolidated Statement of Earnings.

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited) For the year ended December 31, 2002

Financial Statistics (continued)

Net Capital Investment *(C$ millions)*	**Pro forma 2002**
Upstream	
Onshore North America	
Conventional – Canada	$ 2,259
Conventional – U.S.	630
Syncrude	255
Property Acquisitions	1,188
Dispositions	(599)
Net Onshore North America	3,733
Offshore & International	
Ecuador	334
United Kingdom	130
Gulf of Mexico	250
East Coast	223
Other	280
Property Acquisitions	39
Dispositions	(3)
Net Offshore & International	1,253
Midstream & Marketing	
Capital Expenditures	94
Dispositions	–
Net Midstream & Marketing	94
Corporate	70
Corporate Disposition	(93)
Total Net Capital Investment	$ 5,057

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Pro forma Operating Statistics

Sales Volumes	2002					2001				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Produced Gas *(MMcf/d)*										
Canada	2,248	2,375	2,129	2,144	2,348	2,088	2,169	2,153	2,014	2,012
United States	500	654	550	428	365	279	331	281	275	230
United Kingdom	10	8	9	8	11	9	9	10	8	8
	2,758	3,037	2,688	2,580	2,724	2,376	2,509	2,444	2,297	2,250
Oil and Natural Gas Liquids *(bbls/d)*										
Onshore North America										
Conventional Light and Medium Oil	66,333	62,369	65,345	66,807	70,914	72,812	71,819	74,280	72,795	72,340
Conventional Heavy Oil	78,029	86,019	80,797	76,233	68,846	62,881	63,255	66,085	59,777	62,368
Natural Gas Liquids										
Canada	17,399	19,121	16,225	16,796	17,448	15,650	16,586	14,935	15,507	15,563
United States	7,961	11,558	6,702	7,115	6,427	4,734	5,079	5,490	4,408	3,939
Total Onshore North America										
Conventional	169,722	179,067	169,069	166,951	163,635	156,077	156,739	160,790	152,487	154,210
Syncrude	31,556	34,261	36,039	24,295	31,548	30,687	32,347	28,938	29,162	32,319
Total Onshore North America	201,278	213,328	205,108	191,246	195,183	186,764	189,086	189,728	181,649	186,529
Offshore & International										
Ecuador & Argentina	51,081	49,934	55,579	59,864	38,774	51,899	51,055	51,472	53,498	51,582
United Kingdom	10,528	7,786	9,538	11,966	12,889	11,362	10,839	12,669	10,914	11,012
Total Offshore & International	61,609	57,720	65,117	71,830	51,663	63,261	61,894	64,141	64,412	62,594
Total *(BOE/d)*	722,554	777,215	718,225	693,104	700,846	646,025	669,147	661,202	628,894	624,123

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Operating Statistics

Per-unit Results	2002		
	Q4	Q3	Q2
Produced Gas – Canada *($/Mcf)**			
Price, net of transportation and selling**	5.09	3.53	4.11
Royalties	0.77	0.39	0.65
Operating expenses	0.59	0.58	0.54
Netback including hedge	3.73	2.56	2.92
Hedge	(0.08)	0.29	(0.12)
Netback excluding hedge	3.81	2.27	3.04
Produced Gas – United States *(C$/Mcf)**			
Price, net of transportation and selling**	5.16	3.73	3.62
Royalties	1.42	0.99	0.98
Operating expenses	0.28	0.34	0.38
Netback including hedge	3.46	2.40	2.26
Hedge	0.42	0.57	0.06
Netback excluding hedge	3.04	1.83	2.20
Conventional Light and Medium Oil *($/bbl)*			
Price, net of transportation and selling**	35.10	35.12	33.76
Royalties	4.81	4.56	4.36
Operating expenses	7.16	6.58	7.25
Netback including hedge	23.13	23.98	22.15
Hedge	(1.26)	(0.89)	(1.59)
Netback excluding hedge	24.39	24.87	23.74
Conventional Heavy Oil *($/bbl)*			
Price, net of transportation and selling**	24.63	28.55	26.09
Royalties	3.43	3.67	3.09
Operating expenses	5.64	6.71	5.87
Netback including hedge	15.56	18.17	17.13
Hedge	(1.18)	(0.89)	(0.76)
Netback excluding hedge	16.74	19.06	17.89
Total Conventional Oil *($/bbl)*			
Price, net of transportation and selling**	29.04	31.49	29.67
Royalties	4.01	4.07	3.68
Operating expenses	6.28	6.66	6.51
Netback including hedge	18.75	20.76	19.48
Hedge	(1.22)	(0.89)	(1.15)
Netback excluding hedge	19.97	21.65	20.63
Natural Gas Liquids *($/bbl)*			
Price, net of transportation and selling	36.15	31.18	29.92
Royalties	5.95	4.62	4.69
Netback	30.20	26.56	25.23
Syncrude *($/bbl)*			
Price, net of transportation and selling	42.29	42.54	40.09
Gross overriding royalty and other revenue	0.11	0.17	0.16
Royalties	0.43	0.43	0.42
Operating expenses	16.31	13.38	30.47
Netback including hedge	25.66	28.90	9.36
Hedge	(0.94)	(1.19)	(0.42)
Netback excluding hedge	26.60	30.09	9.78
Ecuador Oil *($/bbl)*			
Price, net of transportation and selling	35.38	33.59	31.63
Royalties	12.29	12.51	10.76
Operating expenses	6.04	4.60	5.70
Netback including hedge	17.05	16.48	15.17
Hedge	–	–	(0.04)
Netback excluding hedge	17.05	16.48	15.21
United Kingdom Oil *($/bbl)*			
Price, net of transportation and selling	37.99	39.30	37.78
Operating expenses	11.10	5.71	3.12
Netback	26.89	33.59	34.66

* Excludes the effect of $168 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.

** Operating netbacks for each product include the margin impact of marketing activities related to the purchase and sale of third-party volumes of the similar product.

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

2002 Pro forma Wells Drilled – Exploration

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty Interest
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross
Canada	484	436	84	72	49	39	617	547	190
United States	16	15	–	–	–	–	16	15	–
Total Onshore North America	500	451	84	72	49	39	633	562	190
Australia	–	–	–	–	1	–	1	–	–
Bahrain	–	–	–	–	1	1	1	1	–
Canada	1	–	–	–	1	1	2	1	–
Ecuador	–	–	7	5	–	–	7	5	–
Qatar	–	–	–	–	2	1	2	1	–
United Kingdom	–	–	7	3	2	1	9	4	–
United States	–	–	2	1	3	1	5	2	–
Total Offshore & International	1	–	16	9	10	5	27	14	–
Total	501	451	100	81	59	44	660	576	190
Success Rate (%)							91%	92%	

2002 Pro forma Wells Drilled – Development

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty Interest
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross
Canada	1,798	1,690	489	405	35	27	2,322	2,122	690
United States	323	276	3	3	1	1	327	280	–
Total Onshore North America	2,121	1,966	492	408	36	28	2,649	2,402	690
Canada	–	–	–	–	–	–	–	–	–
Ecuador	–	–	44	37	5	4	49	41	–
United Kingdom	–	–	2	–	–	–	2	–	–
United States	–	–	–	–	–	–	–	–	–
Total Offshore & International	–	–	46	37	5	4	51	41	–
Total	2,121	1,966	538	445	41	32	2,700	2,443	690
Success Rate (%)							98%	99%	
TOTAL WELLS	2,622	2,417	638	526	100	76	3,360	3,019	880
Success Rate (%)							97%	97%	

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Summary of Working Interest Land Holdings

As at December 31, 2002 (thousands of acres)		Developed		Undeveloped		Total	
		Gross	Net	Gross	Net	Gross	Net
Alberta	– Fee	2,537	2,402	2,795	2,771	5,332	5,173
	– Crown	3,762	3,103	8,113	6,871	11,875	9,974
	– Freehold	201	60	543	277	744	337
		6,500	5,565	11,451	9,919	17,951	15,484
British Columbia	– Crown	565	443	4,031	3,256	4,596	3,699
Saskatchewan	– Fee	12	10	481	467	493	477
	– Crown	331	208	1,345	1,112	1,676	1,320
	– Freehold	68	34	282	195	350	229
		411	252	2,108	1,774	2,519	2,026
Manitoba	– Fee	–	1	271	266	271	267
	– Crown	–	–	55	55	55	55
	– Freehold	–	–	23	23	23	23
		–	1	349	344	349	345
Northwest Territories	– Crown	–	–	406	236	406	236
United States	– Federal Lands	334	257	1,304	1,025	1,638	1,282
	– Freehold	370	217	914	452	1,284	669
	– Fee	10	9	17	17	27	26
		714	483	2,235	1,494	2,949	1,977
Total Onshore North America		8,190	6,744	20,580	17,023	28,770	23,767
Beaufort	– Crown	–	–	126	4	126	4
Newfoundland & Labrador	– Crown	–	–	4,333	2,791	4,333	2,791
Northwest Territories	– Crown	–	–	630	202	630	202
Nova Scotia	– Crown	–	–	4,908	3,066	4,908	3,066
Nunavut	– Crown	–	–	817	26	817	26
United States	– Federal Lands	–	–	5,128	1,974	5,128	1,974
Australia		–	–	19,159	6,750	19,159	6,750
Bahrain		–	–	97	48	97	48
Brazil		–	–	1,932	1,488	1,932	1,488
Chad		–	–	108,536	54,268	108,536	54,268
Ecuador		108	30	985	766	1,093	796
Ghana		–	–	3,679	1,471	3,679	1,471
Greenland		–	–	985	985	985	985
Qatar		–	–	2,758	1,103	2,758	1,103
United Kingdom – Offshore		29	4	1,317	414	1,346	418
Yemen		–	–	2,519	1,236	2,519	1,236
Other		–	–	346	17	346	17
Total Offshore & International		137	34	158,255	76,609	158,392	76,643
Total		8,327	6,778	178,835	93,632	187,162	100,410

Notes:

(1) This table excludes approximately 3.8 million gross acres under lease or sublease, reserving to EnCana royalties or other interests.

(2) Fee lands are those in which EnCana owns mineral rights and in which it returns a working interest.

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

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

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

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Pro forma Reserves by Division (excluding Syncrude) – Before Royalties

(Constant Price)

Natural Gas *(Bcf)*	Onshore North America					Offshore & International				
	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total
2002										
PCE End of year 2001	3,079	811	3,890	1,120	5,010	7	–	7	42	49
AEC End of year 2001	3,368	1,152	4,520	2,049	6,569	–	–	–	36	36
Pro forma End of year 2001	6,447	1,963	8,410	3,169	11,579	7	–	7	78	85
Revisions and improved recovery	(356)	93	(263)	(665)	(928)	6	12	18	417	435
Extensions and discoveries	689	658	1,347	483	1,830	–	10	10	24	34
Purchase of reserves in place	449	240	689	341	1,030	–	–	–	–	–
Sale of reserves in place	(133)	(105)	(238)	(389)	(627)	–	–	–	–	–
Sales	(1,003)	–	(1,003)	–	(1,003)	(4)	–	(4)	–	(4)
End of year	6,093	2,849	8,942	2,939	11,881	9	22	31	519	550
2001 PanCanadian										
Beginning of year	2,879	793	3,672	1,132	4,804	9	–	9	42	51
Revisions and improved recovery	193	(123)	70	(194)	(124)	1	–	1	–	1
Extensions and discoveries	380	113	493	92	585	–	–	–	–	–
Purchase of reserves in place	9	28	37	90	127	–	–	–	–	–
Sale of reserves in place	(1)	–	(1)	–	(1)	–	–	–	–	–
Sales	(381)	–	(381)	–	(381)	(3)	–	(3)	–	(3)
End of year	3,079	811	3,890	1,120	5,010	7	–	7	42	49
2001 Alberta Energy Company										
Beginning of year	2,722	1,162	3,884	1,912	5,796	23	25	48	66	114
Revisions and improved recovery	287	(242)	45	(174)	(129)	–	–	–	–	–
Extensions and discoveries	696	201	897	175	1,072	–	–	–	–	–
Purchase of reserves in place	177	116	293	214	507	–	–	–	–	–
Sale of reserves in place	(31)	(85)	(116)	(78)	(194)	(22)	(25)	(47)	(30)	(77)
Sales	(483)	–	(483)	–	(483)	(1)	–	(1)	–	(1)
End of year	3,368	1,152	4,520	2,049	6,569	–	–	–	36	36

Conventional Crude Oil and Natural Gas Liquids *(MMbbls)*	Onshore North America					Offshore & International				
	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total
2002										
PCE End of year 2001	277.0	63.4	340.4	129.9	470.3	21.6	–	21.6	162.8	184.4
AEC End of year 2001	142.3	117.4	259.7	155.2	414.9	72.6	161.1	233.7	82.0	315.7
Pro forma End of year 2001	419.3	180.8	600.1	285.1	885.2	94.2	161.1	255.3	244.8	500.1
Revisions and improved recovery	(55.4)	69.0	13.6	163.9	177.5	18.1	(69.7)	(51.6)	(109.5)	(161.1)
Extensions and discoveries	45.8	75.1	120.9	120.3	241.2	3.0	130.2	133.2	45.9	179.1
Purchase of reserves in place	13.5	4.4	17.9	17.5	35.4	–	–	–	–	–
Sale of reserves in place	(10.6)	(11.2)	(21.8)	(13.1)	(34.9)	–	–	–	–	–
Sales	(61.9)	–	(61.9)	–	(61.9)	(22.7)	–	(22.7)	–	(22.7)
End of year	350.7	318.1	668.8	573.7	1,242.5	92.6	221.6	314.2	181.2	495.4
2001 PanCanadian										
Beginning of year	297.7	102.6	400.3	197.2	597.5	23.7	5.0	28.7	38.0	66.7
Revisions and improved recovery	5.2	2.9	8.1	1.7	9.8	2.1	–	2.1	(1.3)	0.8
Extensions and discoveries	17.9	2.7	20.6	2.0	22.6	–	–	–	132.3	132.3
Purchase of reserves in place	0.4	–	0.4	–	0.4	–	–	–	–	–
Sale of reserves in place	(6.6)	(44.8)	(51.4)	(71.0)	(122.4)	–	(5.0)	(5.0)	(6.2)	(11.2)
Sales	(37.6)	–	(37.6)	–	(37.6)	(4.2)	–	(4.2)	–	(4.2)
End of year	277.0	63.4	340.4	129.9	470.3	21.6	–	21.6	162.8	184.4
2001 Alberta Energy Company										
Beginning of year	95.2	137.2	232.4	140.7	373.1	56.6	177.0	233.6	53.5	287.1
Revisions and improved recovery	52.1	(58.5)	(6.4)	(3.3)	(9.7)	20.0	(38.8)	(18.8)	(14.7)	(33.5)
Extensions and discoveries	14.6	38.6	53.2	17.3	70.5	15.0	23.0	38.0	43.2	81.2
Purchase of reserves in place	0.3	0.2	0.5	0.6	1.1	–	–	–	–	–
Sale of reserves in place	(0.6)	(0.1)	(0.7)	(0.1)	(0.8)	(0.1)	(0.1)	(0.2)	–	(0.2)
Sales	(19.3)	–	(19.3)	–	(19.3)	(18.9)	–	(18.9)	–	(18.9)
End of year	142.3	117.4	259.7	155.2	414.9	72.6	161.1	233.7	82.0	315.7

Total Gas				
Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**
3,086	811	3,897	1,162	**5,059**
3,368	1,152	4,520	2,085	**6,605**
6,454	1,963	8,417	3,247	**11,664**
(350)	105	(245)	(248)	**(493)**
689	668	1,357	507	**1,864**
449	240	689	341	**1,030**
(133)	(105)	(238)	(389)	**(627)**
(1,007)	–	(1,007)	–	**(1,007)**
6,102	2,871	8,973	3,458	**12,431**
2,888	793	3,681	1,174	**4,855**
194	(123)	71	(194)	**(123)**
380	113	493	92	**585**
9	28	37	90	**127**
(1)	–	(1)	–	**(1)**
(384)	–	(384)	–	**(384)**
3,086	811	3,897	1,162	**5,059**
2,745	1,187	3,932	1,978	**5,910**
287	(242)	45	(174)	**(129)**
696	201	897	175	**1,072**
177	116	293	214	**507**
(53)	(110)	(163)	(108)	**(271)**
(484)	–	(484)	–	**(484)**
3,368	1,152	4,520	2,085	**6,605**

Total Liquids					Total MMBOE				
Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**	Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**
298.6	63.4	362.0	292.7	**654.7**	813.0	198.5	1,011.5	486.4	**1,497.9**
214.9	278.5	493.4	237.2	**730.6**	776.2	470.6	1,246.8	584.6	**1,831.4**
513.5	341.9	855.4	529.9	**1,385.3**	1,589.2	669.1	2,258.3	1,071.0	**3,329.3**
(37.3)	(0.7)	(38.0)	54.4	**16.4**	(95.8)	16.6	(79.2)	13.2	**(66.0)**
48.8	205.3	254.1	166.2	**420.3**	163.7	316.8	480.5	250.9	**731.4**
13.5	4.4	17.9	17.5	**35.4**	88.4	44.5	132.9	74.2	**207.1**
(10.6)	(11.2)	(21.8)	(13.1)	**(34.9)**	(32.7)	(28.7)	(61.4)	(78.0)	**(139.4)**
(84.6)	–	(84.6)	–	**(84.6)**	(252.4)	–	(252.4)	–	**(252.4)**
443.3	539.7	983.0	754.9	**1,737.9**	1,460.4	1,018.3	2,478.7	1,331.3	**3,810.0**
321.4	107.6	429.0	235.2	**664.2**	802.8	239.8	1,042.6	431.0	**1,473.6**
7.3	2.9	10.2	0.4	**10.6**	39.6	(17.7)	21.9	(28.6)	**(6.7)**
17.9	2.7	20.6	134.3	**154.9**	81.3	21.5	102.8	146.2	**249.0**
0.4	–	0.4	–	**0.4**	2.0	4.7	6.7	15.0	**21.7**
(6.6)	(49.8)	(56.4)	(77.2)	**(133.6)**	(6.7)	(49.8)	(56.5)	(77.2)	**(133.7)**
(41.8)	–	(41.8)	–	**(41.8)**	(106.0)	–	(106.0)	–	**(106.0)**
298.6	63.4	362.0	292.7	**654.7**	813.0	198.5	1,011.5	486.4	**1,497.9**
151.8	314.2	466.0	194.2	**660.2**	609.2	512.0	1,121.2	523.9	**1,645.1**
72.1	(97.3)	(25.2)	(18.0)	**(43.2)**	120.3	(137.7)	(17.4)	(47.0)	**(64.4)**
29.6	61.6	91.2	60.5	**151.7**	145.5	95.3	240.8	89.5	**330.3**
0.3	0.2	0.5	0.6	**1.1**	29.7	19.5	49.2	36.3	**85.5**
(0.7)	(0.2)	(0.9)	(0.1)	**(1.0)**	(9.6)	(18.5)	(28.1)	(18.1)	**(46.2)**
(38.2)	–	(38.2)	–	**(38.2)**	(118.9)	–	(118.9)	–	**(118.9)**
214.9	278.5	493.4	237.2	**730.6**	776.2	470.6	1,246.8	584.6	**1,831.4**

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Pro forma Reserves by Division (excluding Syncrude) – After Royalties – U.S.

(Constant Price)

Natural Gas *(Bcf)*	Onshore North America					Offshore & International				
	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total
2002										
PCE End of year 2001	2,952	788	3,740	1,011	4,751	7	–	7	42	49
AEC End of year 2001	2,721	909	3,630	1,602	5,232	–	–	–	35	35
Pro forma End of year 2001	5,673	1,697	7,370	2,613	9,983	7	–	7	77	84
Revisions and improved recovery	(462)	43	(419)	(538)	(957)	6	11	17	408	425
Extensions and discoveries	602	558	1,160	410	1,570	–	10	10	23	33
Purchase of reserves in place	362	198	560	279	839	–	–	–	–	–
Sale of reserves in place	(114)	(88)	(202)	(324)	(526)	–	–	–	–	–
Sales	(833)	–	(833)	–	(833)	(4)	–	(4)	–	(4)
End of year	5,228	2,408	7,636	2,440	10,076	9	21	30	508	538
2001 PanCanadian										
Beginning of year	2,782	776	3,558	1,006	4,564	10	–	10	42	52
Revisions and improved recovery	180	(115)	65	(125)	(60)	–	–	–	–	–
Extensions and discoveries	354	107	461	67	528	–	–	–	–	–
Purchase of reserves in place	6	20	26	63	89	–	–	–	–	–
Sale of reserves in place	(1)	–	(1)	–	(1)	–	–	–	–	–
Sales	(369)	–	(369)	–	(369)	(3)	–	(3)	–	(3)
End of year	2,952	788	3,740	1,011	4,751	7	–	7	42	49
2001 Alberta Energy Company										
Beginning of year	2,179	893	3,072	1,247	4,319	20	22	42	62	104
Revisions and improved recovery	234	(171)	63	103	166	–	–	–	–	–
Extensions and discoveries	565	158	723	131	854	–	–	–	–	–
Purchase of reserves in place	147	97	244	181	425	–	–	–	–	–
Sale of reserves in place	(26)	(68)	(94)	(60)	(154)	(19)	(22)	(41)	(27)	(68)
Sales	(378)	–	(378)	–	(378)	(1)	–	(1)	–	(1)
End of year	2,721	909	3,630	1,602	5,232	–	–	–	35	35

Conventional Crude Oil and Natural Gas Liquids *(MMbbls)*	Onshore North America					Offshore & International				
	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total	Proved Producing	Proved Non-Producing	Total Proved	Probable	Total
2002										
PCE End of year 2001	253.2	53.0	306.2	109.9	416.1	21.6	–	21.6	162.8	184.4
AEC End of year 2001	128.4	111.8	240.2	136.4	376.6	51.6	116.8	168.4	60.5	228.9
Pro forma End of year 2001	381.6	164.8	546.4	246.3	792.7	73.2	116.8	190.0	223.3	413.3
Revisions and improved recovery	(60.6)	45.8	(14.8)	130.9	116.1	9.9	(48.6)	(38.7)	(97.9)	(136.6)
Extensions and discoveries	40.5	64.5	105.0	101.6	206.6	2.4	120.3	122.7	36.5	159.2
Purchase of reserves in place	11.4	3.4	14.8	14.2	29.0	–	–	–	–	–
Sale of reserves in place	(9.4)	(9.5)	(18.9)	(10.8)	(29.7)	–	–	–	–	–
Sales	(53.6)	–	(53.6)	–	(53.6)	(16.7)	–	(16.7)	–	(16.7)
End of year	309.9	269.0	578.9	482.2	1,061.1	68.8	188.5	257.3	161.9	419.2
2001 PanCanadian										
Beginning of year	271.3	93.4	364.7	177.2	541.9	23.7	5.0	28.7	38.0	66.7
Revisions and improved recovery	4.3	2.3	6.6	(3.2)	3.4	2.1	–	2.1	(1.3)	0.8
Extensions and discoveries	14.8	2.2	17.0	1.7	18.7	–	–	–	132.3	132.3
Purchase of reserves in place	–	–	–	–	–	–	–	–	–	–
Sale of reserves in place	(3.1)	(44.9)	(48.0)	(65.8)	(113.8)	–	(5.0)	(5.0)	(6.2)	(11.2)
Sales	(34.1)	–	(34.1)	–	(34.1)	(4.2)	–	(4.2)	–	(4.2)
End of year	253.2	53.0	306.2	109.9	416.1	21.6	–	21.6	162.8	184.4
2001 Alberta Energy Company										
Beginning of year	80.0	113.3	193.3	114.6	307.9	40.5	131.3	171.8	39.5	211.3
Revisions and improved recovery	52.1	(38.1)	14.0	6.5	20.5	14.5	(31.6)	(17.1)	(6.4)	(23.5)
Extensions and discoveries	12.9	36.6	49.5	14.9	64.4	10.4	17.1	27.5	27.4	54.9
Purchase of reserves in place	0.3	0.2	0.5	0.5	1.0	–	–	–	–	–
Sale of reserves in place	(0.5)	(0.2)	(0.7)	(0.1)	(0.8)	(0.1)	–	(0.1)	–	(0.1)
Sales	(16.4)	–	(16.4)	–	(16.4)	(13.7)	–	(13.7)	–	(13.7)
End of year	128.4	111.8	240.2	136.4	376.6	51.6	116.8	168.4	60.5	228.9

Total Gas				
Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**
2,959	788	3,747	1,053	**4,800**
2,721	909	3,630	1,637	**5,267**
5,680	1,697	7,377	2,690	**10,067**
(456)	54	(402)	(130)	**(532)**
602	568	1,170	433	**1,603**
362	198	560	279	**839**
(114)	(88)	(202)	(324)	**(526)**
(837)	–	(837)	–	**(837)**
5,237	2,429	7,666	2,948	**10,614**
2,792	776	3,568	1,048	**4,616**
180	(115)	65	(125)	**(60)**
354	107	461	67	**528**
6	20	26	63	**89**
(1)	–	(1)	–	**(1)**
(372)	–	(372)	–	**(372)**
2,959	788	3,747	1,053	**4,800**
2,199	915	3,114	1,309	**4,423**
234	(171)	63	103	**166**
565	158	723	131	**854**
147	97	244	181	**425**
(45)	(90)	(135)	(87)	**(222)**
(379)	–	(379)	–	**(379)**
2,721	909	3,630	1,637	**5,267**

Total Liquids					Total MMBOE				
Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**	Proved Producing	Proved Non-Producing	Total Proved	Probable	**Total**
274.8	53.0	327.8	272.7	**600.5**	768.0	184.2	952.2	448.2	**1,400.4**
180.0	228.6	408.6	196.9	**605.5**	633.4	380.3	1,013.7	469.5	**1,483.2**
454.8	281.6	736.4	469.6	**1,206.0**	1,401.4	564.5	1,965.9	917.7	**2,883.6**
(50.7)	(2.8)	(53.5)	33.0	**(20.5)**	(126.7)	6.4	(120.3)	11.3	**(109.0)**
42.9	184.8	227.7	138.1	**365.8**	143.2	279.5	422.7	210.4	**633.1**
11.4	3.4	14.8	14.2	**29.0**	71.7	36.4	108.1	60.9	**169.0**
(9.4)	(9.5)	(18.9)	(10.8)	**(29.7)**	(28.4)	(24.3)	(52.7)	(64.6)	**(117.3)**
(70.3)	–	(70.3)	–	**(70.3)**	(209.8)	–	(209.8)	–	**(209.8)**
378.7	457.5	836.2	644.1	**1,480.3**	1,251.4	862.5	2,113.9	1,135.7	**3,249.6**
295.0	98.4	393.4	215.2	**608.6**	760.1	227.9	988.0	389.8	**1,377.8**
6.4	2.3	8.7	(4.5)	**4.2**	36.7	(17.1)	19.6	(25.3)	**(5.7)**
14.8	2.2	17.0	134.0	**151.0**	73.8	20.0	93.8	145.2	**239.0**
–	–	–	–	**–**	1.0	3.3	4.3	10.5	**14.8**
(3.1)	(49.9)	(53.0)	(72.0)	**(125.0)**	(3.2)	(49.9)	(53.1)	(72.0)	**(125.1)**
(38.3)	–	(38.3)	–	**(38.3)**	(100.4)	–	(100.4)	–	**(100.4)**
274.8	53.0	327.8	272.7	**600.5**	768.0	184.2	952.2	448.2	**1,400.4**
120.5	244.6	365.1	154.1	**519.2**	487.0	397.3	884.3	372.1	**1,256.4**
66.6	(69.7)	(3.1)	0.1	**(3.0)**	105.3	(98.3)	7.0	17.4	**24.4**
23.3	53.7	77.0	42.3	**119.3**	117.5	80.1	197.6	64.1	**261.7**
0.3	0.2	0.5	0.5	**1.0**	24.8	16.5	41.3	30.6	**71.9**
(0.6)	(0.2)	(0.8)	(0.1)	**(0.9)**	(8.0)	(15.3)	(23.3)	(14.7)	**(38.0)**
(30.1)	–	(30.1)	–	**(30.1)**	(93.2)	–	(93.2)	–	**(93.2)**
180.0	228.6	408.6	196.9	**605.5**	633.4	380.3	1,013.7	469.5	**1,483.2**

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited) For the year ended December 31, 2002

The Consolidated Financial Statements of the Company are prepared in Canadian dollars. The financial information presented below shows the U.S. GAAP financial information and has been translated into U.S. dollars for the convenience of the readers of the Annual Report. The financial information presented below has been translated into U.S. dollars at a rate of $1 Canadian equals $0.633 U.S., the rate of exchange on December 31, 2002. This translation should not be construed as a representation that the Canadian dollar amounts shown in the Consolidated Financial Statements could be converted into U.S. dollars at the rate of $1 Canadian equals $0.633 U.S. or at any other rate.

Consolidated Statement of Earnings prepared in accordance with U.S. GAAP

Year ended December 31 (US$ millions, except per share amounts)	2002
Revenues, Net of Royalties and Production Taxes	$ 6,337
Expenses	
Transportation and selling	363
Operating	910
Purchased product	2,183
Administrative	122
Interest, net	285
Foreign exchange (gain)	(13)
Depreciation, depletion and amortization	1,351
Loss on derivatives	50
Earnings Before the Undernoted	1,086
Gain on corporate disposition	(32)
Income taxes	368
Net Earnings from Continuing Operations	750
Net (Loss) from Discontinued Operations	(1)
Net Earnings	$ 749
Net Earnings per Common Share – Diluted	$ 1.76

Condensed Consolidated Balance Sheet prepared in accordance with U.S. GAAP

As at December 31 (US$ millions)	2002
Assets	
Current assets	$ 2,715
Financial assets	181
Capital assets	14,932
Investments and other assets	245
Goodwill	1,827
	$ 19,900
Liabilities and Shareholders' Equity	
Current liabilities	$ 2,455
Financial liabilities	262
Long-term debt	4,761
Deferred credits and other liabilities	374
Future income taxes	3,222
Preferred securities of subsidiary	289
	11,363
Shareholders' Equity	8,537
	$ 19,900

SUPPLEMENTAL FINANCIAL INFORMATION

(unaudited) For the year ended December 31, 2002

Condensed Consolidated Statement of Cash Flows prepared in accordance with U.S. GAAP

Year ended December 31 (US$ millions)	2002
Cash From Operating Activities	
Net earnings from continuing operations	$ 750
Depreciation, depletion and amortization	1,351
Future income taxes	399
Other	(110)
Cash flow from continuing operations	2,390
Cash flow from discontinued operations	27
Cash flow	2,417
Net change in other assets and liabilities	(14)
Net change in non-cash working capital from continuing operations	(839)
Net change in non-cash working capital from discontinued operations	61
	$ 1,625
Cash Used in Investing Activities	$ (2,571)
Cash From Financing Activities	$ 475

SUPPLEMENTAL OIL AND GAS OPERATING STATISTICS

(unaudited) For the year ended December 31, 2002

Pro forma – Sales (After Royalties)

Year ended December 31	2002
Produced Gas *(MMcf/d)*	
Canada	1,918
United States	364
United Kingdom	10
Total	2,292
Oil and Natural Gas Liquids *(bbls/d)*	
Onshore North America	
Conventional oil	125,267
Natural gas liquids	
Canada	14,836
United States	6,608
Total Onshore North America conventional	146,711
Syncrude	31,355
Total Onshore North America	178,066
Offshore & International	
Ecuador	34,607
United Kingdom	10,528
Total Offshore & International	45,135
Total	223,201

CORPORATE INFORMATION

CORPORATE OFFICERS

Gwyn Morgan
President & Chief Executive Officer

Randall K. Eresman
Senior Executive Vice-President & Chief Operating Officer
President, Onshore North America Division

David J. Boone
Executive Vice-President
President, Offshore & International Operations Division

Brian C. Ferguson
Executive Vice-President, Corporate Development

Gerald J. Macey
Executive Vice-President
President, Offshore & New Ventures Exploration Division

R. W. (Bill) Oliver
Executive Vice-President
President, Midstream & Marketing Division

Gerard J. Protti
Executive Vice-President, Corporate Relations

Drude Rimell
Executive Vice-President, Corporate Services

John D. Watson
Executive Vice-President & Chief Financial Officer

Kerry D. Dyte
General Counsel & Corporate Secretary

Thomas G. Hinton
Treasurer

Ronald H. Westcott
Comptroller

BOARD OF DIRECTORS

Michael N. Chernoff [2,6]
West Vancouver, British Columbia

Patrick D. Daniel [1,5]
Calgary, Alberta

Ian W. Delaney [3,5]
Toronto, Ontario

William R. Fatt [1,2]
Toronto, Ontario

Michael A. Grandin [3,5,6]
Calgary, Alberta

Barry W. Harrison [1,4]
Calgary, Alberta

Richard F. Haskayne, O.C. [3,4]
Calgary, Alberta

John C. Lamacraft [1,3,6]
Toronto, Ontario

Dale A. Lucas [1,5]
Calgary, Alberta

Ken F. McCready [2,5]
Calgary, Alberta

Gwyn Morgan [2a,5a]
Calgary, Alberta

Valerie A. A. Nielsen [2,3]
Calgary, Alberta

David P. O'Brien [7]
Calgary, Alberta

Dennis A. Sharp [2,4]
Calgary, Alberta

T. Don Stacy [1,4,6]
Houston, Texas

James M. Stanford [3,6]
Calgary, Alberta

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

ENCANA HEAD OFFICE

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

TRANSFER AGENTS & REGISTRAR

Common Shares
CIBC Mellon Trust Company
Calgary, Montreal, Toronto

Mellon Investor Services LLC
New York

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

MAILING ADDRESS:

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Adelaide Street Postal Station
Toronto, Ontario, Canada M5C 2W9
Internet Addresses:
inquiries@cibcmellon.com (email)
www.cibcmellon.com (web site)

TRUSTEE & REGISTRARS

CIBC Mellon Trust Company
8.15% Debentures
Calgary, Vancouver, Winnipeg, Toronto, Montreal, Halifax
Canadian Medium Term Notes
7.00% Preferred Securities
Calgary, Toronto

Computershare Trust Company of Canada
8.50% Preferred Securities
Calgary, Toronto

The Bank of New York
9.500% Preferred Securities
7.650% Senior Notes
8.125% Senior Notes
7.375% Senior Notes
New York

The Bank of Nova Scotia Trust Company of New York
6.30% Senior Notes
7.20% Senior Notes
New York

AUDITORS

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

INDEPENDENT ENGINEERING CONSULTANTS

Onshore North America
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Offshore & International
Ryder Scott Company
Houston, Texas

STOCK EXCHANGES

Common Shares (ECA)
Toronto Stock Exchange
New York Stock Exchange

7.00% Preferred Securities
Toronto Stock Exchange (ECA.DB)

8.50% Preferred Securities
Toronto Stock Exchange (ECA.PR.A)

9.50% Preferred Securities
New York Stock Exchange (ECAPRA)

PRINCIPAL SUBSIDIARIES & PARTNERSHIPS[1]

	Percent Owned[2]
EnCana West Ltd.	*100*
Alenco Inc.	*100*
EnCana Oil & Gas (USA) Inc.	*100*
EnCana Energy Holdings Inc.	*100*
EnCana Oil & Gas Partnership	*100*
EnCana Midstream & Marketing[3]	*100*
Marquest Limited Partnership	*100*

(1) Entities whose total assets exceed 10 percent of total consolidated assets of EnCana Corporation or whose revenues exceed 10 percent of the total consolidated revenues of the Corporation for the year ended December 31, 2002.
(2) Includes indirect ownership.
(3) Formerly EnCana Resources.

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

Annual Meeting
Shareholders of EnCana Corporation are encouraged to attend the Annual and Special Meeting being held on Wednesday, April 23, 2003 at 3:00 p.m., local time, at the Hyatt Regency Calgary, 700 Centre Street S.E., Calgary, Alberta. Those unable to do so are asked to sign and return the form of proxy mailed with this Annual Report.

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

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

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

- *Current stock prices*
- *Annual and Interim Reports*
- *Information Circulars*
- *News Releases*
- *Investor presentations*
- *Dividend information*
- *Shareholder support information*

Website: *www.encana.com*

Additional information, including copies of the 2002 EnCana Corporation Annual Report, may be obtained from:

EnCana Corporation
Investor Relations, Corporate Development
1800, 855 – 2nd Street S.W.
P.O. Box 2850
Calgary, Alberta, Canada T2P 2S5
Phone: (403) 645-2000
Visit our Website: www.encana.com

Investor relations' inquiries should be directed to:

Sheila McIntosh
Senior Vice-President, Investor Relations
Email: sheila.mcintosh@encana.com
(403) 645-2194

Greg Kist
Manager, Investor Relations
Email: greg.kist@encana.com
(403) 645-4737

Financial and business media inquiries should be directed to:

Alan Boras
Manager, Media Relations
Email: alan.boras@encana.com
(403) 645-4747

General media inquiries should be directed to:

Dick Wilson
Vice-President, Public Affairs
Email: dick.wilson@encana.com
(403) 645-4777

Abbreviations

bbls	*barrels*
Bcf	*billion cubic feet*
Bcfe	*billion cubic feet equivalent*
BOE	*barrel of oil equivalent*
Btu	*British thermal unit*
GJ	*gigajoule*
km	*kilometre(s)*
kW	*kilowatt*
kWh	*kilowatt hour*
m	*metre(s)*
Mbbls	*thousand barrels*
Mcf	*thousand cubic feet*
Mcfe	*thousand cubic feet equivalent*
MM	*million*
MMbbls	*million barrels*
MMBOE	*million barrels of oil equivalent*
MMBtu	*million British thermal units*
MMcf	*million cubic feet*
MMcfe	*million cubic feet equivalent*
NGLs	*natural gas liquids*
Tcf	*trillion cubic feet*
Tcfe	*trillion cubic feet equivalent*

EnCana
The name EnCana is derived from the words Energy and Canada. The Oxford Dictionary defines "en," the first syllable of EnCana, as a prefix used in "forming verbs from nouns, in the sense 'put into or on'; from nouns or adjectives, in the sense 'bring into the condition of'." In other words, the prefix "en" can be taken to mean "to put into action". EnCana's 2002 annual report emphasizes the "En" aspect of EnCana as a means of illustrating how the Company is putting its words into action.

EnCana Logo
EnCana's strong wordmark reflects a company that is established and sophisticated. The arc is a horizon symbolizing the future potential of the Company. The glint reflects the energy and enthusiasm of EnCana employees. The colours of blue and green honour the history as PanCanadian and AEC. The blue represents water, sky and offshore operations. The green represents onshore operations and the Earth, suggesting growth and reinforcing EnCana's commitment to the environment.

ENCANA™

In the interest of providing EnCana Corporation ("EnCana" or the "Company") shareholders and potential investors with information regarding the Company, certain statements throughout this Annual Report 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", "forecast", "target" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Report include, but are not limited to, statements with respect to: the Company's operating costs and reserves replacement costs for 2003 and beyond; oil and gas prices for 2003; reserves and resource potential for various geographic regions; increases in the Company's crude oil, natural gas liquids and natural gas production for 2003 and beyond; increases in sales of gas and oil in 2003 and beyond; increases in oil extraction rates; the Company's reserves levels; the impact of the Company's risk management program; the Company's capital investment levels and the capital investment levels of the Company's divisions; the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Company; the development of new natural gas storage facilities and increases in the Company's gas storage capacity, injection and withdrawal rates; the targeted minimum growth rate per share for 2003 and beyond; targeted return rates on oil and natural gas exploration and exploitation; the Company's ability to grow production through acquisitions; the results and timing of exploration success; reductions in CO_2 emissions resulting from the Company's CO_2 miscible flood project; the Company's contributions to charitable, environmental, educational and non-governmental organizations; the execution of share purchases under the Company's Normal Course Issuer Bid program; the volatility of world energy prices including crude oil prices; the anticipated timing for the assessment of goodwill impairment and the charging of any impairment to income; the anticipated timing and results of discontinuing the Houston-based merchant energy operation; the proposed use of proceeds from the disposition of the Express and Cold Lake pipeline interests; the timing for completing the OCP pipeline, the expected capacity of the OCP pipeline and the Company's expected final investment in the OCP pipeline; the cost of future dismantlement and site restoration; anticipated geographic regions targeted for production growth, the number of wells and potential wells which may be drilled and potential wellsites available for drilling; the anticipated effect of changes in commodity prices and the U.S./Canadian dollar exchange rate; the impact of legal claims on the financial position and results of operations of the Company; the Company's oilsands strategy and the expected closing date of the sale of a portion of the Company's interest in the Syncrude project; the results of inquiries by U.S. governmental agencies; the Company's ability to extend its debt on an ongoing basis; and future operating results and various components thereof.

SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION

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 Annual Report 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 and resource potential, 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; the risk of international war, hostilities, civil insurrection and instability affecting countries in which the Company operates and international terrorist threats, 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 U.S. 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 exist in the quantities predicted or estimated, and 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 Annual Report, which are made 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 Annual Report are expressly qualified by this cautionary statement.

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