Canadian Natural

annual report 2002

general information

COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "Canadian Natural" or the "Company".

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

bbl	barrel
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcfe	billion cubic feet equivalent
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Cdn	Canadian
CDOR	Canadian Deposit Overnight Rate
E&P	Exploration and production
FPSO	Floating, Production, Storage and Offtake Vessel
Horizon Project	Horizon Oil Sands Project
LIBOR	London Interbank Offered Rate
mbbls	thousand barrels
mbbls/d	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/d	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mcfe/d	thousand cubic feet equivalent per day
mmbbls	million barrels
mmbbls/d	million barrels per day
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Rio Alto	Rio Alto Exploration Ltd.
SCO	Synthetic light crude oil
SO_2	Sulphur dioxide
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States of America
US$	United States dollars
WTI	West Texas Intermediate

FORWARD-LOOKING STATEMENTS

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated in the forward-looking statements.

VOLUME REPORTING

All production, sales and reserve statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion ratio approximates relative heating values.

COMMON SHARE DIVIDEND

In January 2001, the Board of Directors approved payment of a regular quarterly dividend of $0.10 per common share commencing April 2001, which was subsequently increased to $0.125 per common share effective April 2002 and $0.15 per common share effective April 2003. These dividends will be payable in January, April, July and October of each year.

NOTICE OF ANNUAL MEETING

The annual meeting of shareholders will be held at 3:00 p.m. on Thursday, May 8, 2003, in the Ballroom of the Metropolitan Centre, Calgary, Alberta. All shareholders are invited to attend.

METRIC CONVERSION CHART

To convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

our mission statement

"To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity."

the premium value,
defined growth
independent

asset overview

Natural Gas

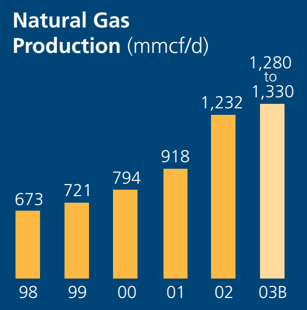
- **Averaged 1,232 mmcf/d in 2002, 98% into the North American market.**
- **Over 3.0 tcf of proved reserves in four Canadian core regions.**
- **Large undeveloped land base in the relatively undeveloped, natural gas prone regions of Northeast British Columbia and Northwest Alberta.**

2002 DEVELOPMENT

- Maximized value of Ladyfern Slave Point pool with additional drilling and facility construction.
- Increased natural gas production before Rio Alto by 14%, while reducing drilling activity to 162 wells from 476 wells.
- Acquired Rio Alto, adding 376 mmcf/d incremental production during the last half of 2002. The assets also added a new core region in Northwest Alberta.

2003 & BEYOND

- Commence development of Northwest Alberta region, with a measured approach to maximize our knowledge base for expanded future activities.
- Drill 500-600 natural gas wells annually.
- 5% year over year growth in production targeted after 2003.



North American Liquids

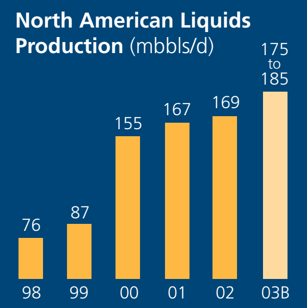
- **Averaged 169 mbbls/d in 2002.**
- **Over 650 mmbbls of proved reserves.**
- **Diverse portfolio of light, primary heavy, thermal heavy, Pelican Lake oil and natural gas liquids.**

2002 DEVELOPMENT

- Drilled 256 oil wells.
- Obtained regulatory approval for high-pressure cyclic steaming at Primrose.
- Initiated an enhanced oil recovery ("EOR") pilot project at Pelican Lake.

2003 & BEYOND

- Drill 48 high-pressure cyclic steam wells at Primrose, adding production in 2004.
- Test alternative EOR processes and optimize the oil recovery at Pelican Lake
- Drill 265 primary heavy oil wells out of 1,000+ inventory.
- Resource potential from inventoried projects totals in excess of 3 billion barrels.



Horizon Oil Sands Project

- **World Class opportunity for oil sands mining.**
- **Six billion barrels of reserves (unbooked).**
- **Supports 232 mbbls/d of light sweet crude oil production for over 40 years, with no declines.**
- **Three phase development plan.**

2002 DEVELOPMENT

- Applied for regulatory approval to construct, operate and reclaim the project.
- Completed majority of Design Basis Memorandum (Phase II of engineering).
- Acquired access to numerous technologies and commenced pre-bid supplier evaluations.

2003 & BEYOND

- Obtain regulatory approvals in 2003 and evaluate form/requirement of partners.
- Commence construction in 2004, first oil in 2008. Phase III completion in 2012.
- Commence Engineering Design Study.
- Continue to work with the Canadian Federal Government to clarify long-term economic consequences of Kyoto implementation.

PLANNED PROJECT TIMELINE

Regulatory Approval	2003
Board of Director Approval	2004
Construction Commences	2004
Phase I Completion	110 mbbls/d 2008
Phase II Completion	155 mbbls/d 2010
Phase III Completion	232 mbbls/d 2012

International – North Sea

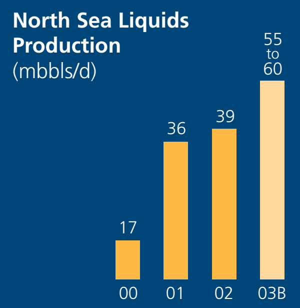
- **Averaged 39 mbbls/d in 2002.**
- **Proved oil reserves of 200 mmbbls and natural gas reserves of over 70 bcf.**
- **Exploitation focused core region.**

2002 DEVELOPMENT

- Acquired additional ownership and operatorship of four producing platforms in Northern North Sea.
- Drilled five oil wells.

2003 & BEYOND

- Improve platform performance in 2003 through expanded maintenance programs.
- Implement waterflood optimization, infill drilling and evaluate drilling satellite pools.
- Drill 18 wells.



International – Offshore West Africa

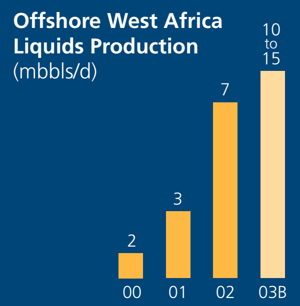
- **Operate offshore in two countries, Côte d'Ivoire and Angola.**
- **Averaged 7 mbbls/d in 2002.**
- **Proved oil reserves of approximately 100 mmbbls and natural gas reserves of 90 bcf.**

2002 DEVELOPMENT

- Commenced production and implemented a waterflood at East Espoir.
- Delineated Baobab discovery, defining approximately 200 mmbbls of recoverable oil.
- Obtained 50% working interest and operatorship of Block 16 in Angola, a significant high risk/high potential asset.

2003 & BEYOND

- Complete repressurized upper zone at East Espoir and drill one satellite pool.
- Commence development of Baobab for first oil in 2005.
- Drill one of two exploration prospects in Block 16, Angola.



# of strategic importance

Governance

We take governance issues very seriously and view our internal controls, cost control and management reporting to be among the best in the industry. We continue to take additional steps to further enhance our corporate governance.

Today more than ever before, corporations must conduct their affairs in a manner that demonstrates openness and instills confidence in their shareholders and stakeholders. It is with these intentions that we at Canadian Natural have developed a plan for ongoing improvements to our Corporate Governance.

The Board of Directors, as part of its overall stewardship of the Company, is taking proactive steps to ensure Canadian Natural complies with the regulatory requirements of the United States Sarbanes-Oxley Act of 2002 as mandated by the Securities and Exchange Commission, the proposed new listing standards of the New York Stock Exchange and the existing Corporate Governance Guidelines of the Toronto Stock Exchange. As well, Canadian Natural continues to meet all requirements of the various other regulatory authorities to which it is subject.

The Company has established a Nominating and Corporate Governance Committee to oversee and assist our progress and compliance with the new requirements.

The committees of the Board of Directors are chaired by independent and unrelated directors and are comprised of the:

- Nominating and Corporate Governance Committee;
- Audit Committee;
- Compensation Committee;
- Reserves Committee; and
- Safety, Health and Environmental Committee.

The members, roles and responsibilities of the Board of Directors are fully discussed in the Company's Information Proxy Circular.

Our financial disclosures are reputed as some of the best in the industry as we have greatly increased the transparency of disclosures. We have a clean operation, clean balance sheet and strong internal and management controls.

Rio Alto Acquisition

The Rio Alto acquisition represents a significant addition to an already strong natural gas asset portfolio. The Northwest Alberta core region is in an area of the Western Canadian Sedimentary Basin that is relatively undeveloped and contains significant natural gas reserves in numerous zones.

The new Northwest Alberta core region provides significant upside potential to Canadian Natural. We now have an additional region with a large, high quality landbase and an extensive underutilized infrastructure. Additionally, because we operate virtually all of our assets and are the majority owner, we can take a measured approach in our development. In the northern portion we see geological attributes similar to our existing North Alberta core region. Over time, we expect to extract up to 1 tcf of new natural gas reserves in this area. In the southern portion, the technically complex Cardium formation could provide up to 0.8 tcf in new natural gas reserves. Our strategy here is to take our time, unlock the geology and reduce costs.

The timing of the acquisition was also significant. While we could not predict the sharp increases in natural gas pricing over the last quarter of 2002, we were aware that natural gas is becoming a scarce resource. The opportunity to buy the Rio Alto assets came at a time of weaker natural gas prices due to high storage levels. We took advantage and immediately started to reap the benefits.

Heavy Oil Market Opportunities

We have one of the strongest heavy oil portfolios in western Canada. We show discipline in our development approach to ensure sustainable returns. The recycle ratios on heavy oil are among the best compared to other commodities in a normal price environment.

Canadian Natural has over 3 billion barrels of additional heavy oil development potential. We take a very measured approach in the development of these reserves in order to ensure that we do not flood our traditional markets with product, thereby reducing our netbacks and economic returns. The opportunity, therefore is to develop new, alternative markets for our heavy oil. We currently see opportunities to expand existing markets through the addition of coking capacity to existing refineries. We also see opportunities to work with pipeline operators to facilitate access to tanker facilities and create a worldwide market for our heavy oil. These capabilities will take time to bring to fruition, but we see this as a major catalyst to significant future growth opportunities.

Horizon Oil Sands Project

This world class project will require significant capital expenditures prior to first production. Our financing approach will consider cash flow expectations, business and equity partnership opportunities and various debt financing alternatives.

We remain conservative in our approach to costing the Horizon Project. We have built in the same costs as the previous oil sands project's final costs and on that basis expect that Phase I will require $4.9 billion in capital. Phase II and III expansions will be financed through Phase I cash flows. We expect no equity issuances to complete this project. Rather, we will examine all other options including the opportunities to forward-hedge commodity prices to reduce cash flow risk coupled with the utilization of business partners to reduce our own capital expenditure profile and various debt financing alternatives. We will also examine ownership partner opportunities as necessary. Our basic premise is to maximize ownership and control, while ensuring that we are prudently managing our economic exposures and financial strength. During the heavy construction periods of 2006 and 2007, we will inventory other major project developments and expend funds only for base E&P production growth and the Horizon Project.

International Strategies

Internationally our two production bases will provide different types of development opportunities. Together they represent opportunities to increase international production to 100,000 bbls/d by the end of 2005.

The United Kingdom sector of the North Sea represents the bulk of our current international production and we see this region as an excellent exploitation base. We will continue to consolidate our presence in the area and work to drive down unit operating costs, increase field recovery factors and drill satellite pools. This work adds value both through the generation of new economic reserves and through the further deferral of future abandonment costs. Offshore West Africa is characterized as an exploration and exploitation base and its upside potential nicely complements the reliability of the North Sea exploitation base. In Côte d'Ivoire the initial redevelopment of the Espoir field has led to an exploration discovery at Baobab, with additional exploration prospects in the future. We see up to 10 years of exploration and development activity on our existing land base, with production well beyond that. Offshore Angola represents a high risk/high potential exploration opportunity in one of the most prolific light oil basins in the world.

Canadian Natural is one of the largest independent crude oil and natural gas producers in the world. We achieved this status through continued application of our value creation objectives and defined growth strategy. We have a low-cost, diversified combination of assets in North America, the North Sea and Offshore West Africa, which enables us to generate significant value, even in challenging economic environments. Our balanced mix of natural gas, light oil and heavy oil production combined with a major oil sands mining project represents one of the strongest and most diverse asset portfolios of any energy producer in the world.

financial and operating highlights

	2002	2001[1]	2000[1]
FINANCIAL ($ millions, except per share data)			
Revenue	**$ 4,083.2**	$ 3,588.8	$ 3,260.6
Cash flow from operations attributable to common shareholders[2]	**$ 2,254.0**	$ 1,920.0	$ 1,883.6
Per common share – basic	**$ 17.63**	$ 15.83	$ 16.14
– diluted	**$ 16.99**	$ 15.23	$ 15.64
Net earnings attributable to common shareholders[3]	**$ 569.8**	$ 642.6	$ 767.1
Per common share – basic	**$ 4.46**	$ 5.30	$ 6.57
– diluted	**$ 4.31**	$ 5.17	$ 6.39
Business combinations	**$ 2,393.2**	$ –	$ 1,687.3
Capital expenditures, net of dispositions	**$ 1,676.2**	$ 1,884.5	$ 1,136.0
Long-term debt	**$ 4,074.0**	$ 2,669.2	$ 2,454.5
Shareholders' equity	**$ 4,868.1**	$ 3,807.0	$ 3,203.1

(1) Restated for change in accounting policy and to conform to current year presentation.
(2) After dividend on preferred securities.
(3) After dividend and revaluation of preferred securities.

	2002	2001[1]	2000[1]
OPERATING			
Daily Production Before Royalties			
Crude oil and NGLs (mbbls/d)			
North America	**169**	167	155
North Sea	**39**	36	17
Offshore West Africa	**7**	3	2
	215	206	174
Natural gas (mmcf/d)			
North America	**1,204**	906	793
North Sea	**27**	12	1
Offshore West Africa	**1**	–	–
	1,232	918	794
Barrel of oil equivalent (mboe/d)	**421**	359	306
Average Prices Before Royalties			
Crude oil and NGLs ($/bbl)			
North America	**$ 27.04**	$ 21.00	$ 28.15
North Sea	**$ 39.79**	$ 38.66	$ 44.61
Offshore West Africa	**$ 40.10**	$ 33.57	$ 45.77
Company average	**$ 29.76**	$ 24.31	$ 29.99
Natural gas ($/mcf)			
North America	**$ 3.78**	$ 5.19	$ 4.53
North Sea	**$ 2.75**	$ 2.51	$ 3.66
Offshore West Africa	**$ 4.82**	–	–
Company average	**$ 3.76**	$ 5.16	$ 4.53
Drilling Activity (net wells, excluding stratigraphic test/service wells)			
North America	**444**	736	774
North Sea	**5**	2	1
Offshore West Africa	**4**	1	–
	453	739	775
Core Undeveloped Land Holdings (thousands of net acres)			
North America	**10,213**	6,272	6,276
North Sea	**410**	236	211
Offshore West Africa	**943**	1,258	1,528

Reserves Before Royalties	2002	2001	2000
Crude oil and NGLs (mmbbls)			
Proved			
North America	**665**	644	642
North Sea	**200**	85	102
Offshore West Africa	**96**	61	37
	961	790	781
Probable			
North America	**77**	95	88
North Sea	**73**	23	33
Offshore West Africa	**70**	51	9
	220	169	130
Total	**1,181**	959	911
Natural gas (bcf)			
Proved			
North America	**3,048**	2,566	2,360
North Sea	**71**	94	91
Offshore West Africa	**90**	69	66
	3,209	2,729	2,517
Probable			
North America	**402**	349	402
North Sea	**18**	24	23
Offshore West Africa	**31**	27	19
	451	400	444
Total	**3,660**	3,129	2,961
Barrels of oil equivalent (mmboe)			
Proved	**1,496**	1,245	1,201
Probable	**295**	236	204
Total	**1,791**	1,481	1,405

Our strategy is defined and effective. It has enabled us to grow from under 1,000 boe per day in 1988 to over 450,000 boe per day in 2003.

ESSENTIAL ELEMENTS OF OUR STRATEGY

ALLOCATE CAPITAL TO MAXIMIZE RETURNS

We put ourselves in a position to build value for the long term while still taking advantage of short-term market aberrations. For example in 2002, we increased heavy oil drilling to take advantage of low differentials. We proactively look for such opportunities on a weekly basis and are nimble enough to deliver.

DEFINED GROWTH, VALUE-ENHANCEMENT PLAN FOR EACH OF OUR PRODUCTS AND BASINS

We carry a large inventory of projects, which allows us to continually high-grade our capital allocation.

MAINTAIN BALANCE IN FOUR WAYS

We are balanced in our product mix, with just under 50% of our production being natural gas, and the remainder being a mix of light, Pelican Lake, primary heavy and thermal heavy oil. We are balanced in our project time horizons and have near-, mid-, and long-term projects proceeding simultaneously. We balance our exploitation focus with targeted exploration and property acquisitions. Finally, from a financial perspective, we maintain a strong balance sheet and balance our sources of financing and debt maturity profile.

OPPORTUNISTIC MAJOR ACQUISITIONS

Each and every one of our major acquisitions was opportunistic and in each case they have taken us to a stronger and higher level as a company.

CONTROL COSTS THROUGH AREA KNOWLEDGE AND DOMINATION OF CORE FOCUS REGIONS

In this business, the low-cost operator will ultimately prevail. We control our costs through maintaining core focus regions, by understanding, controlling and dominating the land base and infrastructure. This allows us to get our production on stream quickly and cost effectively.

Left to right: William Clapperton, Tim McKay, Réal Cusson, Allan Markin, Martin Cole, Steve Laut, Allen Knight.

letter to shareholders

Last year was another strong performance by Canadian Natural in all facets of our operations. We are proud to have built the Premium Value, Defined Growth Independent.

Our strategy is very effective in facilitating our objective to maximize value creation on a per share basis and ensure that we meet our return on capital requirements. The essence of the strategy is to optimize capital allocations to build value in the near, mid and long terms. In order to achieve this, we believe that a strong, balanced asset portfolio and a flexible approach to project development are critical. We have both of these attributes. We have a significant portfolio of opportunities in each of our commodities and core regions and we now operate and control virtually all of our assets around the world.

We target 10% annualized growth in each of our per-share, value creation metrics, and have more than delivered on this objective during 2002 and over the past ten years:

	2002 Annual Growth	10-year Compound Growth
Cash flow per share	11%	36%
Net asset value per share	12%	28%
Production per share	11%	24%
Reserves per share	10%	25%

Production volumes in 2002 were 17% higher than 2001 and proved reserves increased by 20%. These improvements, along with strong commodity, pricing allowed the Company to generate record cash flow from operations of $2.3 billion compared with $1.9 billion in 2001.

Other specific accomplishments during 2002 align with our strategies as follows:

OPPORTUNISTIC MAJOR ACQUISITION

- The acquisition of Rio Alto in July increased North American natural gas production by 376 mmcf/d during the last half of 2002 and provided a new core region with high potential in Northwest Alberta. It is expected that Canadian Natural can add between 1.3 and 1.8 tcf in new natural gas reserves from this region over the next seven years.

CORE REGION CONTROL AND DOMINATION

- The acquisition of additional ownership interests and transition to operator of four producing platforms in the North Sea enables Canadian Natural to pursue a more aggressive exploitation program.
- Entered into a Production Sharing Agreement, CI-400, in offshore Côte d'Ivoire extending landholdings along the promising Espoir/Baobab trend.

CAPITAL ALLOCATION TO MAXIMIZE RETURNS

- Shifted capital during the year toward increased oil drilling activity to take advantage of lower than expected heavy oil price differentials.

EXPLOITATION FOCUS

- Brought the Ladyfern field on stream as expected and fully exploited this exceptional asset.
- Commenced first production from the Espoir field located offshore Côte d'Ivoire.
- Commenced the Pelican Lake enhanced oil recovery study. This project has the potential to significantly increase recoverable reserves.

BUILD VALUE-ENHANCEMENT PLAN FOR EACH CORE REGION

- Declared commerciality on the Baobab field, located offshore Côte d'Ivoire, with first production expected in 2005. This field contains an estimated 200 million barrels of recoverable reserves and is owned 61% by Canadian Natural.
- Filed regulatory applications for the 6 billion barrel Horizon Oil Sands Project. Government approval is expected in late 2003.
- Obtained regulatory approval for the Primrose in-situ oil development plan, providing the ability to significantly grow thermal oil volumes over the next few years.
- Entered into a Production Sharing Agreement on Block 16 located offshore Angola. This block provides high risk/high potential exploration upside in one of the world's most prolific light oil basins.
- Continued to add undeveloped land in natural gas prone areas to maintain natural gas well inventory.

FINANCIAL STRENGTH AND BALANCE

- Issued US $1.1 billion in additional 10- and 30-year notes, serving to both diversify debt holdings and terming out over 50% of debt maturities beyond the Horizon Oil Sands Project construction years.

As we look toward the future, the Company has maintained the integrity of its roots with several core competencies and competitive advantages, including:

- An employee culture that expects value creation from every investment and expenditure decision;
- A high quality and deep management team;
- An asset base capable of generating significant free cash flow; and
- Being a low cost producer.

Of the major independent E&Ps, Canadian Natural exits 2002 as the second-most levered by investment exposure to North American natural gas markets. Despite severe declines at the Ladyfern field, which commenced in the fall 2002, we expect to maintain 2002 exit production levels throughout 2003. We have a significant land base and prospect

Left to right: Brian Illing, Douglas Proll, Réal Doucet,
John Langille, Mary-Jo Case, Lyle Stevens, Cameron Kramer.

inventory in Northeast British Columbia and Northwest Alberta, two of the most prospective regions of the Western Canadian Sedimentary Basin.

The strategic acquisition of Rio Alto brought with it the Northwest Alberta region, which contains both extensive multi-zone Cretaceous plays in the northern portion and a significant Cardium zone play in the southern portion. Canadian Natural shareholders are the beneficiaries of the work initiated by Rio Alto, including an extensive seismic database and a high quality land base containing numerous potential hydrocarbon traps close to an infrastructure designed to handle volumes well in excess of those currently being produced. Our approach to extracting superior returns from this acquisition is very much a measured one. We are taking a disciplined approach to development to ensure that we can bring on new natural gas at a low cost and with lower risk. Our 2003 results to date are promising, meaning that we will ramp up our development of this core region in 2004.

We also remain the second largest producer of heavy oil in Canada and have extensive capabilities for future development. Our conventional heavy oil inventory will provide over 1,000 drilling locations and hundreds of recompletions over the next few years. Having recently attained Alberta Government approvals for conversion to high-pressure steam capability, the Primrose thermal oil development plan is proceeding with the drilling of new high-pressure well pads in 2003, adding production in 2004. Over time and as market conditions warrant, we will eventually bring on up to 100,000 barrels per day of heavy oil production at this field.

During 2002 we filed our regulatory submissions for the Horizon Oil Sands Project and completed much of the second phase engineering requirements. This world-class project will produce 232,000 bbls/d of light, sweet synthetic crude oil, with no production declines for over 40 years, right next door to the largest market in the world. We expect Government approvals in 2003 with construction commencing in 2004 and first production in 2008.

The majority of our producing international assets are located in the United Kingdom sector of the North Sea. We believe that this region exhibits business characteristics similar to western Canada of the early 1990's and that the exploitation focus of this mature basin fits directly with our core strengths. Over time we hope to acquire interests in properties around new hubs or our existing hubs.

Our other international assets are located in offshore Côte d'Ivoire and offshore Angola. In Côte d'Ivoire we dominate the land base and infrastructure surrounding our leases. We have one project on stream (Espoir) and are ramping up production, a second project (Baobab) under development and have significant land holdings for future exploration upside. In Angola we have a very exciting exploration block containing at least two significant prospects, one of which we will drill in late 2003.

The ability to generate superior cash flow remains the foundation of our success. Our confidence in cash flow generation capability has resulted in our Board of Directors declaring a 20% increase in our dividend to $0.60 per common share per annum.

Based upon our budgeted 2003 oil pricing of US $24.00 WTI per barrel and natural gas pricing of US $4.00 NYMEX per mmbtu, Canadian Natural continues to generate significant free cash flow, which will enable us to spend over $800 million in 2003 on future oriented growth projects while still reducing long-term indebtedness. Today's commodity pricing is well in excess of our budgeted price forecast for each of our products, resulting in potential 2003 cash flows well in excess of our $2.3 billion capital budget. We will use a minimum of 50% of this excess free cash flow to repay outstanding indebtedness, and up to 25% will be allocated to each of our share buy-back program and additional capital spending in the latter half of the year. To date we have acquired over 450,000 shares under our buy-back program.

Finally, we have also made adjustments to Board and Management Governance. The addition of two new independent directors and the formation of new independent committees of the Board further strengthen the stewardship of the Company.

We are well positioned to deliver continued growth and robust returns into 2003 and beyond. We expect current year production to grow by about 10% over 2002 levels, with the majority of that growth coming from conventional oil drilling in North America, the North Sea and Offshore West Africa. In North America we will also substantially increase our natural gas drilling program by more than 260%. In so doing, we will complete our set-up drilling program in our new Northwest Alberta natural gas region in order to establish the groundwork for an aggressive 2004 drilling program. We will also commence drilling of new high-pressure wells at our Primrose in-situ play, which will yield incremental production in 2004.

We have a very strong, low-risk asset base and we look forward to being one of the few oil and natural gas producers that can provide both visible growth and value creation for our shareholders.

Allan P. Markin
Chairman
March 18, 2003

John G. Langille
President

our team

World class performance requires a world class team. This team is *very* effective at working together for the creation of shareholder value.

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review of operations

In 2002, we continued to follow our defined operating strategy. We reallocated capital to take advantage of favourable heavy oil differentials and increased our heavy oil drilling program. We completed an opportunistic acquisition of Rio Alto and we increased our control in our core regions. We operate close to 100% of our North American and Offshore West African assets and 80% of our North Sea operations. We have an improved balance in our current production and in our asset inventory portfolio.

review of operations

PRODUCTION AND SALES

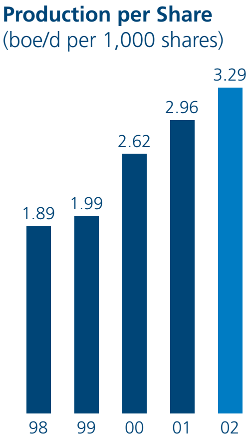
The Company's natural gas sales rose significantly in 2002, averaging 1,232 mmcf/d, a 34% increase over 2001 sales. Two major events impacting natural gas production were:

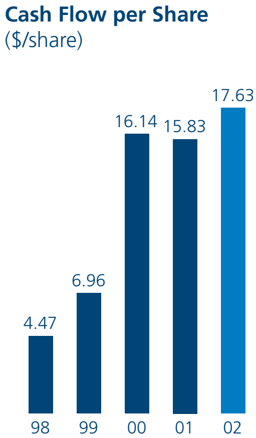
- the completion of the Ladyfern pool development, where production averaged 168 mmcf/d in 2002 compared with 40 mmcf/d in 2001;
- the Rio Alto acquisition on July 1, 2002, which provided an additional 376 mmcf/d of production during the last half of the year and 190 mmcf/d to the Company's yearly average.

Crude oil and natural gas liquids production averaged 215,335 bbls/d, up 4% from 2001 levels. North American liquids production increased 2% from 2001 due to increased NGLs production associated with the Rio Alto acquisition, modest increases in heavy oil production and synergistic light and heavy oil acquisitions. Production of primary and thermal heavy oil volumes increased by 1,198 bbls/d over 2001 volumes despite Canadian Natural proactively curtailing 15,000 bbls/d of heavy oil production in the first quarter when price differentials were higher than normal. A price recovery occurred late in the first quarter, enabling the Company to resume heavy oil production and implement development projects during the last nine months of the year.

Modest increases in production were realized in the North Sea where average production increased by 2,624 bbls/d from 2001 levels through the continued exploitation of the existing pools and through the mid-year acquisition of additional working interests in the Northern North Sea. The commissioning of the Espoir field in Côte d'Ivoire fueled Offshore West African oil production growth of 3,388 bbls/d, despite termination of production at the Kiame field in Angola.

Canadian Natural's activities in 2002 have resulted in natural gas becoming a more significant portion of the Company's producing asset mix at the expense of the heavier crude blends.





	2002		2001	
	Production mboe/d	**Mix** %	Production mboe/d	Mix %
Natural gas	**206**	**49**	153	42
North America light oil and NGLs	**42**	**10**	35	10
Pelican Lake oil (1)	**29**	**7**	35	10
Primary heavy oil	**59**	**14**	57	16
Thermal heavy oil	**39**	**9**	40	11
North Sea light oil	**39**	**9**	36	10
Offshore West Africa light oil	**7**	**2**	3	1
Total	**421**		359	

(1) Pelican Lake oil is 14 – 17° API oil, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

SEISMIC

With Canadian Natural's emphasis on internally generated prospects, both 2-D and 3-D seismic are key to exploration success. In Canada, Canadian Natural invested $39.6 million during 2002 to acquire new seismic data and to purchase and reprocess existing data. In total, the Company shot 2,698 kilometres of conventional seismic and 307 square kilometres of 3-D data. In addition, more than 6,340 kilometres of conventional seismic and 361 square kilometres of 3-D data were purchased. This excludes the 57,820 kilometres of conventional seismic and 14,565 square kilometres of 3-D seismic acquired through the Rio Alto transaction. Internationally, Canadian Natural uses seismic extensively to determine the viability of its exploration prospects. Since commencing operations outside Canada, the Company has been actively involved in proprietary seismic programs covering over 1,228 square kilometres of 3-D seismic and 8,150 kilometres of conventional seismic. Additionally, over 53,500 kilometres of conventional data and 7,000 square kilometres of 3-D seismic were purchased.

review of operations

UNDEVELOPED LAND

Canadian Natural owns one of the largest undeveloped land inventories in western Canada. During 2002, the Company's undeveloped net acreage reached 10.2 million net acres, growing by 61% over the 6.3 million net acres in 2001. Approximately 2.9 million net acres was acquired through the acquisition of Rio Alto, which also created a new core region within Northwest Alberta. Other acreage was primarily added to the Company's core regions of Northeast British Columbia and North Alberta. The substantial land base provides the necessary assets for future exploration and exploitation of oil and natural gas reserves.

CORE CANADIAN LANDHOLDINGS
(thousands of acres)

	2002			2001		
	Gross	**Net**	**Average Interest %**	Gross	Net	Average Interest %
Developed	**5,013**	**3,832**	**76**	4,403	3,578	81
Undeveloped	**12,241**	**10,213**	**83**	7,228	6,272	87
Total	**17,254**	**14,045**	**81**	11,631	9,850	85

DRILLING ACTIVITY

Canadian Natural drilled 900 wells in 2002 compared with 1,092 wells in 2001. The 2002 drilling program resulted in 162 natural gas wells, 264 oil wells, 27 dry and abandoned wells, 441 stratigraphic test wells and 6 service wells. The 39% reduction in drilling activity (excluding stratigraphic test/service wells) from the prior year was comprised of a 66% reduction in natural gas well drilling and a 14% increase in oil well drilling.

The Company's natural gas drilling occurred across 4 of its 5 core regions: Northeast British Columbia, Northwest Alberta, North Alberta and South Alberta. Of the 162 natural gas wells that were drilled, 29 were high density wells targeting shallow natural gas plays. The overall decrease in natural gas drilling reflects Canadian Natural's decision to defer current natural gas drilling and build location inventory to offset anticipated Ladyfern production declines.

In North America, Canadian Natural drilled 16 light oil wells, 86 horizontal wells at its Pelican Lake property, 1 thermal heavy oil well and 153 primary heavy oil wells. Internationally, in the North Sea the Company drilled 5 oil wells and 1 water injection well. In Côte d'Ivoire, Canadian Natural drilled 3 oil wells, 1 water injection well and 1 dry and abandoned wells. Excluding stratigraphic test wells and service wells, Canadian Natural achieved an overall success rate of 94% and maintained an average working interest of 85%, preserving the practice of operating with high ownership.

DRILLING ACTIVITY
(number of wells)

	2002		2001	
	Gross	**Net**	Gross	Net
Natural gas	**183**	**162**	576	476
Oil	**316**	**264**	270	231
Dry and abandoned	**32**	**27**	36	32
Subtotal	**531**	**453**	882	739
Stratigraphic test/service wells	**456**	**447**	356	353
Total	**987**	**900**	1,238	1,092
Success rate, excluding stratigraphic test/service wells		**94%**		96%

CORE REGION FOCUS

	Net Undeveloped Land (thousands of acres)		Drilling Activity (net wells)	
	2002	2001	**2002**	2001
Northeast British Columbia	**1,513**	1,032	**48**	81
Northwest Alberta	**1,821**	521	**13**	11
North Alberta	**5,935**	3,797	**475**	408
South Alberta	**666**	654	**55**	326
Southeast Saskatchewan	**161**	151	**5**	4
Horizon Oil Sands Project	**117**	117	**293**	257
North Sea	**410**	237	**6**	3
Offshore West Africa	**943**	1,094	**5**	2

RESERVES AND RESERVE REPLACEMENTS

Canadian Natural retains independent petroleum engineering consultants, Sproule Associates Limited ("Sproule"), to evaluate the Company's proved and probable oil and natural gas reserves and prepare the Evaluation Report on the Company's total reserves. For the year ended December 31, 2002, the independent evaluator's report incorporated 89% of the Company's reserve value, with the Company internally evaluating the remaining 11%. The Board of Directors of the Company has an independent Reserves Committee, which has met with Sproule and carried out independent due diligence procedures with Sproule as to the Company's reserves.

During 2002 Canadian Natural replaced 301% of its production and increased reserves per common share by 10%. Natural gas reserve additions totaled 218% of production. Crude oil and NGL replacement ratios were 380%, reflecting an expanded heavy oil drilling program in Canada, property acquisitions in the North Sea and drilling success in Côte d'Ivoire.

The Company's strategy of exploitation coupled with exploration and opportunistic acquisitions continues to be successful and has resulted in an increase in reserves per common share during every year of Canadian Natural's existence.

In its evaluation, Sproule has booked 33% of the Company's proved boes as proved undeveloped ("PUDs") which is consistent with prior year levels.

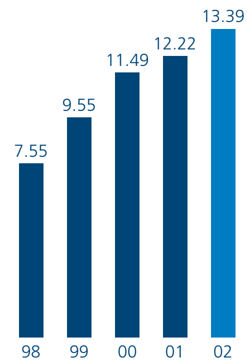
Sproule has assigned PUDs to 45% of Canadian Natural's proved crude oil and NGL reserves. In North America, the ratio of PUDs remained at 40%. The majority of the Company's crude oil and NGL PUDs are associated with:

- the Primrose thermal project, where tertiary recovery performance has been established and the pool has been well delineated to justify future expansions;
- the Espoir field in Côte d'Ivoire, where the ongoing pool drilling and waterflood development have established proved reserves that will require further development;
- the future development of the Baobab pool in Côte d'Ivoire where two exploration wells have established the proven potential in the reservoir; and
- the North Sea, where proved future development exists through infill drilling and waterflood optimization.

Sproule has assigned PUDs to 12% of the Company's proved natural gas reserves, of which a portion is associated with secondary natural gas horizons to be produced following primary zone depletion, as well as solution gas conservation from the oil projects identified above.

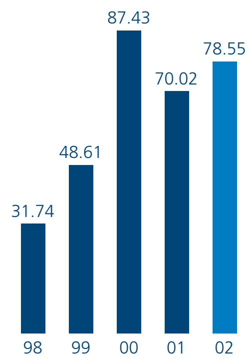
No reserves have been assigned to the Horizon Oil Sands Project by the Company or Sproule. Canadian Natural's internal estimate of recoverable bitumen is 6 billion barrels. Canadian Natural owns 100% of these estimated reserves with production scheduled to commence in 2008.

Reserves per Share (1)
(boe/share)



(1) Based upon total reserves, excludes reserves associated with the Horizon Project.

Net Asset Value per Share (2)
($/share)



(2) Based upon pre-tax net present value of reserves discounted at 10%, including 50% of probable reserve value, undeveloped land valued at $75/acre, less long-term debt. Excludes abandonment costs.

RESERVES BEFORE ROYALTIES (1)

	December 31, 2002				
	Proved Developed	**Proved Undeveloped**	**Proved Total**	**Probable**	**Total**
Crude oil & NGLs (mmbbls)					
North America	**396**	**269**	**665**	**77**	**742**
North Sea	**104**	**96**	**200**	**73**	**273**
Offshore West Africa	**33**	**63**	**96**	**70**	**166**
	533	**428**	**961**	**220**	**1,181**
Natural gas (bcf)					
North America	**2,721**	**327**	**3,048**	**402**	**3,450**
North Sea	**56**	**15**	**71**	**18**	**89**
Offshore West Africa	**33**	**57**	**90**	**31**	**121**
	2,810	**399**	**3,209**	**451**	**3,660**
Total reserves (mmboe)	**1,001**	**495**	**1,496**	**295**	**1,791**
Present value of reserves ($ millions)(2)(3)					
10% discount	**$ 10,967**	**$ 1,811**	**$ 12,778**	**$ 1,038**	**$ 13,816**
15% discount	**$ 9,461**	**$ 1,266**	**$ 10,727**	**$ 780**	**$ 11,507**

	December 31, 2001				
	Proved Developed	Proved Undeveloped	Proved Total	Probable	Total
Crude oil & NGLs (mmbbls)					
North America	382	262	644	95	739
North Sea	54	31	85	23	108
Offshore West Africa	21	40	61	51	112
	457	333	790	169	959
Natural gas (bcf)					
North America	2,288	278	2,566	349	2,915
North Sea	19	75	94	24	118
Offshore West Africa	17	52	69	27	96
	2,324	405	2,729	400	3,129
Total reserves (mmboe)	845	400	1,245	236	1,481
Present value of reserves ($ millions)(2)(3)					
10% discount	$ 7,850	$ 1,699	$ 9,549	$ 847	$ 10,396
15% discount	$ 6,679	$ 1,177	$ 7,856	$ 642	$ 8,498

(1) 89% of the total December 31, 2002 reserves were independently evaluated by Sproule.
(2) Excludes provisions for abandonment costs and income taxes.
(3) Value of the probable reserves is reduced by 50% to account for risk.

RESERVES RECONCILIATION

	North America	North Sea	Offshore West Africa	Total
Crude Oil and NGLs (mmbbls)				
Proved Reserves				
Reserves, December 31, 2000	642	102	37	781
Extensions & discoveries	14	–	38	52
Property purchases	16	–	8	24
Property disposals	(1)	–	–	(1)
Production	(61)	(13)	(1)	(75)
Revisions of prior estimates	34	(4)	(21)	9
Reserves, December 31, 2001	644	85	61	790
Extensions & discoveries	**31**	**1**	**18**	**50**
Property purchases	**51**	**112**	**–**	**163**
Property disposals	**(1)**	**(18)**	**–**	**(19)**
Production	**(62)**	**(14)**	**(3)**	**(79)**
Revisions of prior estimates	**2**	**34**	**20**	**56**
Proved Reserves, December 31, 2002	**665**	**200**	**96**	**961**
Probable Reserves				
Reserves, December 31, 2000	88	33	9	130
Extensions & discoveries	(1)	(1)	–	(2)
Property purchases	1	–	19	20
Property disposals	–	–	–	–
Revisions of prior estimates	7	(9)	23	21
Reserves, December 31, 2001	95	23	51	169
Extensions & discoveries	**–**	**(1)**	**(14)**	**(15)**
Property purchases	**10**	**24**	**–**	**34**
Property disposals	**–**	**(4)**	**–**	**(4)**
Revisions of prior estimates	**(28)**	**31**	**33**	**36**
Probable Reserves, December 31, 2002	**77**	**73**	**70**	**220**
Total Reserves, December 31, 2002	**742**	**273**	**166**	**1,181**
Natural Gas (bcf)				
Proved Reserves				
Reserves, December 31, 2000	2,360	91	66	2,517
Extensions & discoveries	470	1	–	471
Property purchases	167	–	24	191
Property disposals	(25)	–	–	(25)
Production	(331)	(4)	–	(335)
Revisions of prior estimates	(75)	6	(21)	(90)
Reserves, December 31, 2001	2,566	94	69	2,729
Extensions & discoveries	**132**	**–**	**5**	**137**
Property purchases	**872**	**18**	**–**	**890**
Property disposals	**(4)**	**(56)**	**–**	**(60)**
Production	**(439)**	**(10)**	**(1)**	**(450)**
Revisions of prior estimates	**(79)**	**25**	**17**	**(37)**
Proved Reserves, December 31, 2002	**3,048**	**71**	**90**	**3,209**
Probable Reserves				
Reserves, December 31, 2000	402	23	19	444
Extensions & discoveries	9	(1)	–	8
Property purchases	23	–	11	34
Property disposals	(6)	–	–	(6)
Revisions of prior estimates	(79)	2	(3)	(80)
Reserves, December 31, 2001	349	24	27	400
Extensions & discoveries	**8**	**–**	**(17)**	**(9)**
Property purchases	**82**	**6**	**–**	**88**
Property disposals	**–**	**(6)**	**–**	**(6)**
Revisions of prior estimates	**(37)**	**(6)**	**21**	**(22)**
Probable Reserves, December 31, 2002	**402**	**18**	**31**	**451**
Total Reserves, December 31, 2002	**3,450**	**89**	**121**	**3,660**

review of operations

RESERVES CLASSIFICATION BY PRODUCT (%)

(boe basis at December 31, 2002)	Proved Developed	Proved Undeveloped	Proved Total	Probable	Total
Light Oil and NGLs					
North America	8	–	8	8	8
North Sea	7	6	13	25	15
Offshore West Africa	2	4	6	23	9
Total	17	10	27	56	32
Heavy Oil					
North America – primary	7	1	8	17	10
North America – thermal	9	16	25	–	21
Total	16	17	33	17	31
Pelican Lake Oil					
North America	3	1	4	1	3
Total Crude Oil and NGLs					
North America	27	18	45	26	42
North Sea	7	6	13	25	15
Offshore West Africa	2	4	6	23	9
Total	36	28	64	74	66
Natural Gas					
North America	30	4	34	23	32
North Sea	1	–	1	1	1
Offshore West Africa	–	1	1	2	1
Total	31	5	36	26	34
Total boe	67	33	100	100	100

FINDING AND ON-STREAM COSTS

	2002	2001	2000	Three Year Total
Capital Expenditures ($ millions)				
Business combinations	$ 2,393.2	$ –	$ 1,687.3	$ 4,080.5
Net property acquisitions	440.2	519.2	150.2	1,109.6
Land acquisition and retention	113.5	100.5	79.7	293.7
Seismic evaluations	63.4	94.6	40.5	198.5
Well drilling, completion and equipping	625.6	635.3	508.9	1,769.8
Pipeline and production facilities	292.2	395.0	335.7	1,022.9
Total Net Reserve Replacement Expenditures	$ 3,928.1	$ 1,744.6	$ 2,802.3	$ 8,475.0
Cost of Net Reserves Replacement After Reserves Revisions ($/boe)				
Proved only	$ 9.70	$ 9.91	$ 7.09	$ 8.68
Proved and probable	$ 8.47	$ 8.43	$ 6.20	$ 7.55

RESERVES EVALUATION PRICING MODELS

Crude Oil and NGLs December 31, 2002	Company Average Price (Cdn $/bbl)	WTI at Cushing, Oklahoma (US $/bbl)	Hardisty Heavy 12° API (Cdn $/bbl)	North Sea Brent (US $/bbl)
Reserves Evaluation Pricing Model (1)				
2003	**30.59**	**25.99**	**25.92**	**24.49**
2004	**27.91**	**23.60**	**23.78**	**22.08**
2005	**25.18**	**21.63**	**21.16**	**20.09**
2006	**25.48**	**21.96**	**21.83**	**20.39**
2007	**26.22**	**22.29**	**22.89**	**20.70**
December 31, 2001				
Reserves Evaluation Pricing Model (2)				
2002	18.36	19.90	14.41	18.40
2003	20.85	20.64	18.44	19.11
2004	23.44	21.12	21.58	19.29
2005	23.75	21.44	22.13	19.58
2006	24.01	21.76	22.62	19.87

Natural Gas December 31, 2002	Company Average Price (Cdn $/mcf)	Henry Hub, Louisiana (US $/mmbtu)	Alberta AECO (Cdn $/mcf)	British Columbia Plantgate (Cdn $/mcf)
Reserves Evaluation Pricing Model (1)				
2003	**5.73**	**4.39**	**5.89**	**5.94**
2004	**5.22**	**4.05**	**5.38**	**5.43**
2005	**4.62**	**3.61**	**4.77**	**4.82**
2006	**4.31**	**3.40**	**4.45**	**4.48**
2007	**4.46**	**3.45**	**4.61**	**4.66**
December 31, 2001				
Reserves Evaluation Pricing Model (2)				
2002	3.80	2.89	3.80	3.75
2003	4.33	3.24	4.35	4.30
2004	4.32	3.25	4.36	4.26
2005	4.33	3.25	4.36	4.26
2006	4.42	3.29	4.44	4.34

(1) Sproule January 1, 2003 pricing model adjusted for quality and transportation.
(2) Sproule January 1, 2002 pricing model adjusted for quality and transportation.

review of operations

MARKETING

NATURAL GAS

In 2002, average North American natural gas prices as measured by the NYMEX decreased by 26% from the previous year to US $3.25 per mmbtu. Similarly, pricing in Alberta dropped by 35% to $4.07 per mmbtu.

During the first quarter of 2002, warm weather reduced heating loads from the residential and commercial sectors and when combined with the sluggish economy, caused the overall demand for natural gas to be weak. With readily available supplies and strong storage positions, the quarterly average prices were US $2.40 per mmbtu on the NYMEX and $3.35 per mmbtu in Alberta. The North American exploration and development companies responded to the lower projected cash flows by substantially cutting back their drilling programs.

The Alberta price differential to the NYMEX widened to US $1.17 per mmbtu, causing an abnormally low Alberta price during the third quarter as export capacity was curtailed due to the combined maintenance programs on two major pipelines.

The fourth quarter of 2002 saw cooler temperatures in eastern markets partially offset by warmer than normal weather prevailing on the west coast. The high storage levels were drawn down very quickly and when combined with the weak drilling activity, resulted in prices strengthening to US $3.99 per mmbtu on the NYMEX and $5.25 per mmbtu in Alberta.

Canadian Natural increased its total sales by 34% in 2002 to 1,232 mmcf/d and realized an overall wellhead price of $3.76 per mcf, down 27% from last year. Canadian Natural continues to control its portfolio with direct sales in 2002 representing 86% of the total with the remaining 14% split among the major supply aggregators. Seventy-three percent of sales were indexed at prevailing market prices at geographically diversified delivery points.

Canadian Natural expects 2003 to provide a strong natural gas pricing environment. Although drilling activity has already picked up dramatically in the first quarter of 2003, the overall industry production is expected to decline a further 1.6% this year after a drop of 4.2% in 2002. The overall storage positions at the end of March 2003 are likely to be at their lowest levels in more than five years. Confirming the tight supply situation, prices have already spiked above US $20.00 per mmbtu in eastern markets and above $16.00 per mmbtu in Alberta. While the March NYMEX settled at US $9.13 per mmbtu the Alberta March index settled at $10.13 per mmbtu.

Canadian Natural's production is forecast to average approximately 1.3 bcf/d in 2003 and current pricing strip would yield a record average wellhead price exceeding $7.00 per mcf compared with Canadian Natural's 2003 budgeted price of $5.20 per mcf.

CRUDE OIL AND NGLS

The average crude oil price in 2002 was up 1% from the previous year with the North American benchmark WTI at US $26.11 per barrel and the North Sea benchmark Brent, at US $25.01 per barrel.

The continued weakness in the American economy resulted in relatively weak pricing in the first quarter with an average price of US $21.67 per barrel for WTI and US $21.14 per barrel for Brent, before increasing 21% in the second quarter to US $26.26 per barrel for WTI and US $25.03 per barrel for Brent. Tracking the overall economy, crude oil demand strengthened steadily throughout the year in response to the geopolitical challenges presented by the Middle East, North Korea and the Venezuelan situations. A stressed worldwide supply environment yielded fourth quarter prices averaging US $28.17 per barrel with spot prices spiking at US $33.65 per barrel.

The differential for Canadian heavy crude oil grades was 39% lower in 2002, with an average differential for benchmark Lloydminster Blend to WTI of US $6.50 per barrel. This, combined with a weaker Canadian dollar, resulted in a 30% stronger price for Canadian heavy crude oil.

Canadian Natural's realized oil and natural gas liquids price in 2002 was $29.76 per barrel, up 22% from last year, while production was up 4% at 215 mbbls/d. The portfolio mix of oil and natural gas liquids in 2002 was 50% for light and Pelican Lake grades, 4% for natural gas liquids and 46% for heavy grades.

Canadian Natural expects pricing levels to be strong in the early part of 2003 as supplies remain challenged, with many geopolitical uncertainties and the realistic potential for serious temporary disruptions. Although productive capacity can continue to grow, many logistical issues remain to be resolved, resulting in estimated short-term incremental supply availability of approximately 1.25 mmbbls/d. Pipelines are needed in Russia and tankers are required in the Middle East to significantly increase beyond that level.

For 2003, under the current pricing outlook, our production forecast of approximately 250 mbbls/d would yield an average $30.00 per barrel against a WTI of US $28.25 per barrel.

MIDSTREAM

Canadian Natural's midstream assets consist of three crude oil pipeline systems and an 84 megawatt cogeneration plant at Primrose where the Company has a 50% working interest. Approximately 82% of Canadian Natural's heavy oil production was transported to the international mainline liquids pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline.

In 2002, the Company installed condensate injection and heat exchange facilities on the ECHO pipeline, maximizing pipeline utilization and reducing operating costs by 15%. Improved operating practices on the Pelican Lake Pipeline system resulted in a 23% reduction in operating costs.

Canadian Natural plans to continue to maximize value from its pipeline systems in 2003, by increasing the ECHO Pipeline capacity to 72 mbbls/d from 58 mbbls/d. The Company also plans to analyze the merits of additional terminaling facilities at Hardisty, Alberta, that would further enhance heavy oil blending economics.

ENVIRONMENT, HEALTH & SAFETY, AND COMMUNITY

Canadian Natural believes that ethical, socially responsible operations and environmental stewardship are integral to long-term success. We comply with or exceed all regulatory standards and guidelines and operate within our licenses and regulatory approvals. Our accomplishments in 2002 provide an excellent foundation for continuous improvement in environment, health and safety and community performance.

REDUCING THE ENVIRONMENTAL FOOTPRINT

Environmental protection is a fundamental value to us; therefore, we are proactive in reducing the Company's environmental footprint and work together with community and industry groups for a better, sustainable energy industry.

ACHIEVEMENTS

- Canadian Natural continues to invest major resources in flaring and venting reduction programs. At the Primrose operations flaring has been reduced by 50%, and by the end of 2003, flaring reductions will accumulate to 95% of 2001 values. The conserved natural gas from this and similar conservation projects is used as fuel for steam generation. During the past three years, over 100 successful casing natural gas conservation projects have been implemented. In 2002, more than 35% of the solution gas from the Company's primary heavy oil wells was conserved as compared to only 5% in 1999.
  At Pelican Lake, more than 96% of the solution gas is conserved today, compared to 55% in 2000.
- Since 1995, we have reduced greenhouse gas ("GHG") emissions by more than 4 million tonnes. Despite the dramatic growth of our operations, including energy intensive areas such as thermal heavy oil, Canadian Natural's GHG emissions are 21.6% lower than 1997 baseline values. Furthermore, we plan to reduce emissions by an additional 2.8 million tonnes over the next three years and expect ongoing reductions in emissions per unit.
- The Federal Government released Canada's Climate Change Plan in the fall of 2002 with a goal of implementing it by 2005 to meet the first Kyoto Protocol reporting period. The Company continues to participate with various industry associations and governments to ensure that Canada's GHG implementation policy related to the Kyoto Protocol is workable.
- As part of major project planning, Canadian Natural proactively incorporates environmental goals. For example, the Primrose heavy oil expansion project plan included a goal to reduce dependence on fresh groundwater and instead use mostly brackish water by 2007. For the Horizon Oil Sands Project, the design has incorporated numerous environmental mitigation measures such as using improved sulphur recovery technologies that will recover 99.2% of the SO_2 versus the regulatory requirement of 98.8%.
- As one of the largest independent oil and natural gas producers, Canadian Natural realizes the importance of its role in working with other stakeholders in addressing industry wide issues. The Company is involved in numerous working groups such as the Lakeland Industry and Community Association, in oil sands industry groups such as the Cumulative Environmental Management Association and the Regional Issues Working Group.
- International operations support the International Chamber of Commerce Charter on Sustainable Development. Canadian Natural has identified four areas of focus for international operations:
  1. Use water-based, environmentally friendly drilling muds whenever possible;
  2. Develop and implement a management strategy related to GHG emission reductions;
  3. Exercise care with respect to all waste produced through effective waste management plans; and
  4. Minimize produced water volumes onshore and offshore and strive to better regulatory requirements.

ENSURING A HEALTHY AND SAFE WORKPLACE

Canadian Natural conducts operations in a way that protects the health and safety of employees, contractors, the public and the environment.

ACHIEVEMENTS

- Based upon industry best practices, Canadian Natural is implementing new systems around the globe to better monitor and steward health and safety programs.
- Over the last few years, efforts to heighten safety awareness have met with excellent results and positive feedback from regulators. The Company's 2002 statistics show a 31% decrease in total recordable injuries for employees and a 35% decrease for contractors from 2001 levels.
- Increased internal safety and compliance audits, with action plans and rigorous timelines for completion, are conducted regularly at all of Canadian Natural's sites. All new production facilities acquired in 2002 were similarly audited to ensure safe and healthy working environments.

ESTABLISHING AND MAINTAINING PRODUCTIVE RELATIONSHIPS WITH COMMUNITIES

Canadian Natural works co-operatively with the communities where business is conducted, interacting with stakeholder groups and individuals, government agencies and industry committees.

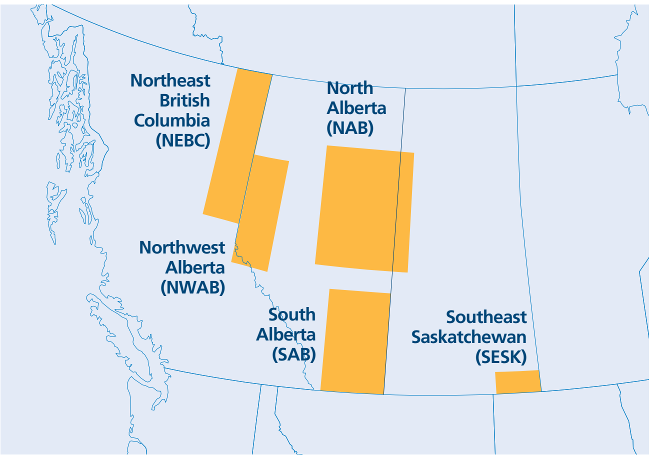
ACHIEVEMENTS

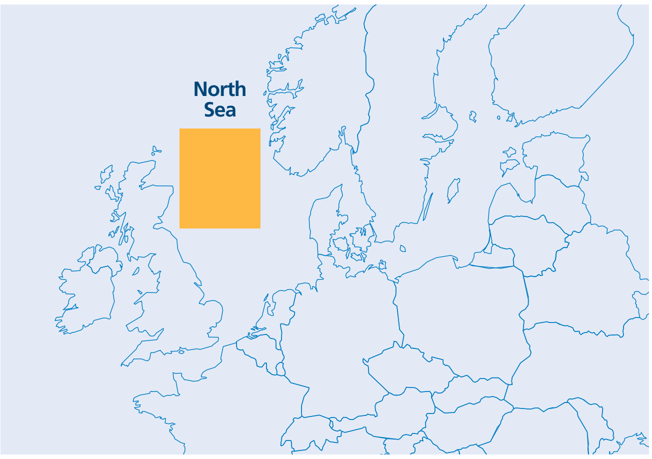
- Local landmen and community relations staff have proactively worked with neighbours near its operations in order to identify potential impacts and to take practical steps to address local concerns.
- For larger projects such as the Horizon Project, the Company utilized long-term consultation programs that focus on identifying potential issues and worked with stakeholders to ensure successful implementation of mitigation measures.
- In 2002, the Company developed a working agreement with the Bigstone First Nation in Alberta. Canadian Natural was also one of the signatories to the Athabasca Tribal Council/All Parties Core Agreement that ensures long-term mutually beneficial relationships between five First Nations, the oil sands industry and the three levels of government.
- Canadian Natural launched the Company's Building Futures Training and Education Program, providing scholarships to 31 students in 2002 and supporting other educational initiatives such as the Petroleum Employment Training program.
- Canadian Natural's policies promote local employment and business opportunities, enabling local communities to participate in economic benefits.
- The Company continues to contribute to the quality of life in communities where it operates. In Canada, hundreds of community initiatives are supported through Canadian Natural's donations and gifts in kind. In Angola, where civil war has ended after 27 years, the Company has committed funds over the next four years to finance health and education projects.

review of assets

We manage our asset base by adhering to a defined growth strategy. Our philosophy is to dominate production, infrastructure and undeveloped land within our core regions. This creates a growth platform based on exploitation, exploration, and strategic acquisitions while enabling a low-cost structure.

review of assets





Canadian Natural focuses on five core regions in western Canada and has international operations that are concentrated in offshore environments in the UK sector of the North Sea as well as Côte d'Ivoire and Angola in Offshore West Africa. Canadian Natural believes that keeping a strong prospect inventory in each of its products and basins is essential to provide the flexibility to develop assets in a manner that achieves superior returns. The Company's development and exploration project inventory and its product diversity creates near-, mid- and long-term growth opportunities.

The Company controls its development activities and costs by maintaining operatorship and maximizing working interests. Low operating costs are achieved through owning and operating the infrastructure, maximizing facility utilization and having a large land base that supplies additional development opportunities. Capital is minimized due to the scale of the Company's operations, through optimal project scheduling and by controlling the pace of development.

Internationally, Canadian Natural employs the identical philosophy developed for western Canada. Specifically, the goal is to operate, maximize working interests and control the development of the Company's projects. The Company develops assets in new areas at a modest pace until sufficient expertise and competence is gained to allow it to maximize the profitability of that area.

Natural Gas – Core Region Summary

	NEBC	NWAB	NAB	SAB	Other
Average production (mmcf/d)					
2001	317	51	357	162	31
2002	**451**	**171**	**420**	**146**	**44**
Natural gas facilities, operated	71	24	102	27	–

North American Crude Oil and NGLs – Core Region Summary

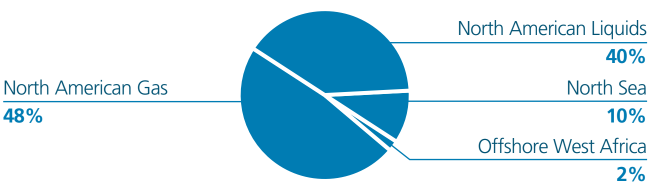
	NEBC	NWAB	NAB	SAB	SESK	Other
Average production (mbbls/d)						
2001	9	1	141	7	7	2
2002	**7**	**7**	**136**	**9**	**9**	**1**
Crude oil facilities, operated	8	7	23	32	35	–

International Crude Oil – Core Region Summary

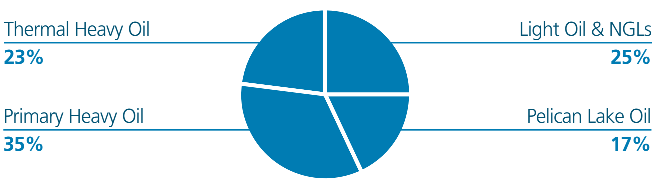
	Offshore West Africa	North Sea
Average production (mbbls/d)		
2001	3	36
2002	**7**	**39**
Platforms/FPSOs, operated	1	5

The Company's 2002 average product and basin allocations are:

Corporate BOE Production



North American Oil Production



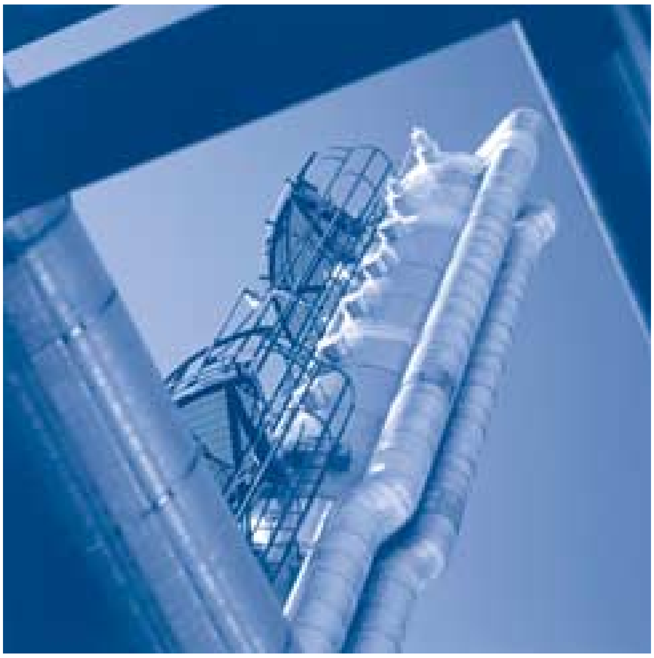
Natural Gas

Canadian Natural continued to grow natural gas production in 2002 and the expansion of the Company's prospect inventory strengthened its strategic plan of annually increasing natural gas production in North America.

The Company's current natural gas production is concentrated over four of its North American core regions: Northeast British Columbia, Northwest Alberta, North Alberta and South Alberta.

Canadian Natural is the largest natural gas producer in British Columbia, and this core region represents 37% of the Company's natural gas production. The Company's experience in the province, its large undeveloped land base and existing infrastructure affords a significant competitive advantage in the highly prospective region of Northeast British Columbia. Canadian Natural has production, infrastructure and undeveloped lands in three distinct areas. Most northerly is the Helmet area, where the Company targets the low risk, regionally extensive, natural gas charged Jean Marie carbonate formation with horizontal wells. Natural gas is produced in the Fort St. John area from an array of carbonate and sandstone reservoirs. Most southerly is the Foothills area where the Company targets deeper Mississippian and Triassic age reservoirs in this highly deformed structural area.

In 2002, Canadian Natural completed the development of the Ladyfern Slave Point pool in the Fort St. John area. The Company drilled seven wells into the pool in 2002, augmenting the eight wells drilled in 2001. Canadian Natural's production from this prolific pool peaked at more than 200 mmcf/d in June and declined sharply to 113 mmcf/d by December. After only 18 months on production, the Company's total production from the pool had reached 76 bcf at year end. This highlights the economic and productive potential of the Slave Point pools in Northeast British Columbia. Ultimately, Canadian Natural predicts that total cash flow from Ladyfern will exceed $300 million as compared to the $195 million of capital invested. The Company also discovered two new Slave Point pools in 2002, a significant pool at Buick Creek and a small, isolated pool near Ladyfern. Production from the Buick Creek pool has stabilized at 50 mmcf/d; however, the small pool at Ladyfern had ceased production by year end due to water influx. Canadian Natural continues to hold significant, undeveloped acreage on the prospective Slave Point trend, providing a competitive advantage, both in the event of a discovery by the Company or by a competitor. Any additional Slave Point discoveries are expected to be 10 to 30 bcf in size.



Canadian Natural created a significant new core region in Northwest Alberta through the acquisition of Rio Alto. This region contains exceptional exploration and exploitation opportunities as well as substantial available capacity within an extensive, owned and operated infrastructure. Canadian Natural produces liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 3,000 to 15,000 feet. The northern portion of this core region provides extensive multi-zone Cretaceous opportunities similar to the geology of the Company's North Alberta core region. The southern portion provides a significant opportunity in the regionally extensive Cretaceous Cardium zone. The Cardium is a complex, tight, natural gas reservoir where high productivity can be achieved due to greater matrix porosity or natural fracturing. Canadian Natural has chosen to pursue a modest 2003 development plan in this area so that comprehensive geological, geophysical and engineering studies can be completed.

Natural gas in the North Alberta and South Alberta core regions is produced from shallow, low risk multi-zone prospects. The Company continues to develop new prospects in these regions and modest production growth is still being achieved. The Rio Alto acquisition added 143 mmcf/d of synergistic production in the North Alberta core region and an additional 1.3 million acres of undeveloped land. The gathering of solution gas associated with the Company's oil production in this region also provides another source of enhanced natural gas sales.

Canadian Natural is the second largest independent producer of natural gas in Canada. The Company has effectively doubled natural gas production volumes over the last five years and targets 5% average annual growth rates after 2003.

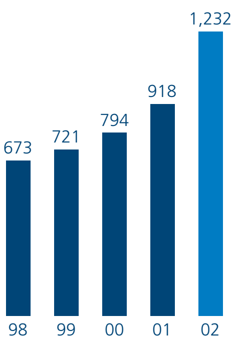
2002 ACHIEVEMENTS

- Production averaged 1,232 mmcf/d, a 34% increase over 2001 production, and accounted for 49% of the Company's total boe production;
- 98% of the Company's natural gas production was from western Canada and was sold into the North American market;
- Development of the prolific Slave Point pool at Ladyfern was completed, increasing field production to average 168 mmcf/d compared with 40 mmcf/d in 2001;
- The mid-year acquisition of Rio Alto provided a 190 mmcf/d increase in 2002 average production and created a major new core region with significant future growth opportunities;
- Drilled 162 successful wells representing 36% of the Company's oil and natural gas well drilling activity. This is a 66% decrease from 2001 reflecting the Company's decision to defer natural gas drilling to 2003-04 to offset anticipated Ladyfern production declines;
- 290 wells were recompleted to access secondary producing horizons;
- $40 million was spent on synergistic acquisitions within core regions (excluding Rio Alto); and
- Discovered two new Slave Point pools.

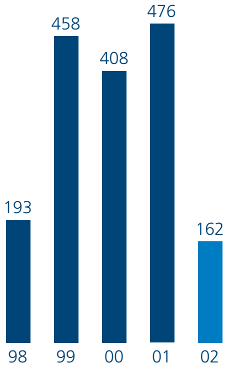
2003 PLANS

- Drill approximately 600 wells;
- Recomplete approximately 300 wells;
- Continue detailed geophysical, geological and engineering studies of the Cardium formation in Northwest Alberta;
- Continue evaluation of the Slave Point trend, drilling up to six wells; and
- Allocate $691 million in capital spending to exploration and development opportunities.

Annual Production
(mmcf/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



review of assets

Strategic, opportunistic acquisition – Rio Alto

WHAT DID CANADIAN NATURAL BUY?

	Total	Northwest Alberta	North Alberta
Undeveloped land, (thousands of acres)	2,900	1,600	1,300
Proved reserves acquired (bcfe)	980	650	330
Production – July 2002 (mmcf/d)	400	257	143
(mbbls/d)	11	10	1
Seismic acquired 2-D (km)	57,820	–	–
Seismic acquired 3-D (km^2)	14,565	–	–
Facilities	46	16	30

WHAT IS THE STRATEGIC FIT? WHY BUY THE ASSETS?

Rio Alto operated in two core regions: the North Alberta region, which augmented Canadian Natural's own North Alberta region, and Northwest Alberta. Canadian Natural had long identified the upside of the Northwest Alberta core region; however, as a late entrant it would be difficult to follow the Company's principle of dominating the land base and the support infrastructure. Rio Alto provided both a high quality land base and an underutilized infrastructure from which to grow. The acquired land base has significant development potential since Rio Alto had extensive seismic coverage over much of the region prior to purchasing lands. Future exploration and development projects will take advantage of the large undeveloped land base, the high quality seismic database and the underutilized facilities, thereby reducing development costs.

WHAT IS THE UPSIDE IN EACH OF THE CORE REGIONS?

NORTH ALBERTA

The assets in this region fit very well within Canadian Natural's existing North Alberta core region and provide excellent cost reduction opportunities as well as continued development and exploration potential. This core region remains exploitation focused and should provide a stable production profile into the future.

NORTHWEST ALBERTA (NORTHERN PORTION)

The Cretaceous geological targets are very similar to those of the Company's North Alberta region and therefore are very familiar to Canadian Natural. The Company expects that this area will provide the most upside from the acquisition. Over the next few years this area will grow to become a prime exploration and development area for Canadian Natural.

NORTHWEST ALBERTA (SOUTHERN PORTION)

The highly complex Cardium formation is the primary target in this area. The Cardium represents an extensive, underdeveloped play paralleling the Rocky Mountains. The Company will be undertaking detailed geological and engineering studies in 2003 to enhance success in this challenging area.

The following table quantifies the potential upside of the Northwest Alberta region:

	Northern Portion	Southern Portion
Potential drilling locations	550-725	200-300
Reserves upside (bcfe)	800-1,000	500-760

RIO ALTO WAS A GOOD OPERATOR, WHY DOES CANADIAN NATURAL BELIEVE IT CAN BE MORE SUCCESSFUL?

Canadian Natural takes pride in being one of the low cost producers in every basin in which it operates. Inherent in this ability is taking the time to understand the geology, the costs and the challenges of an area. Canadian Natural wants to take full advantage of the seismic, drilling and production results provided by Rio Alto and plans to fully analyze the data prior to embarking on large development programs. The Company's size and inventory of other prospects enables it to be patient in this regard. Canadian Natural believes that returns on capital will be enhanced by spending additional time to understand the area complexities and plan for effective execution. The Company has built a skilled team, composed of both Rio Alto and Canadian Natural employees, bringing the expertise of both organizations together to capitalize on the strengths and knowledge of each.

Light Oil and NGLs – North America

During 2002, Canadian Natural exceeded its goal of maintaining North American light oil production near 2001 levels by increasing production by 14%. This production growth was achieved through waterflood optimization, modest drilling programs, production optimization and strategic acquisitions within core regions. Natural gas liquids production also increased by 48% in 2002, primarily due to the acquisition of Rio Alto.

Light oil and NGLs are produced from all five western Canadian core regions. Many of the Company's light oil pools are produced under waterflood, resulting in significant oil recovery improvements by maintaining reservoir pressure and improving sweep efficiency. Canadian Natural focuses on waterflood optimization through detailed reservoir characterization, analysis of pattern performance, improved well operating practices and improved fluid processing at the surface. The Company considers light oil growth opportunities to be limited in the mature pools of the Western Canadian Sedimentary Basin and is not predicting significant growth from these assets. Canadian Natural will continue to pursue synergistic acquisitions within its core regions.

Canadian Natural has shown its ability to maintain light oil volumes in the mature Western Canadian Sedimentary Basin.

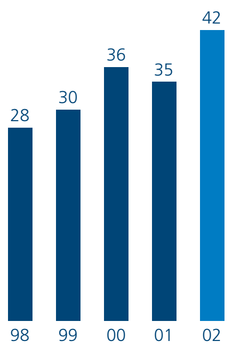
2002 ACHIEVEMENTS

- Production of light oil and NGLs averaged 41,945 bbls/d, a 20% increase over 2001 production, and accounted for 10% of the Company's total boe production;
- Drilled 16 successful wells, which represents 4% of the Company's oil and natural gas well drilling activity;
- 10 wells were recompleted to access secondary producing horizons; and
- $110 million was spent on synergistic acquisitions within core regions (excluding Rio Alto).

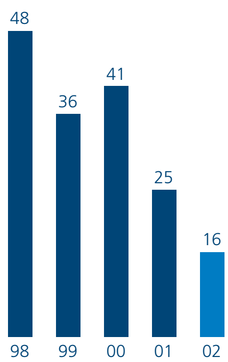
2003 PLANS

- Drill 45 wells focused primarily on infill/step-out wells in Southeast Saskatchewan and Nipisi infills in North Alberta;
- Recomplete 15 wells;
- Allocate $92 million in capital spending on exploration and development opportunities; and
- Maximize recovery and production through waterflood optimization and evaluate implementing new waterfloods in Northwest Alberta.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



review of assets

Pelican Lake Oil – North America

This large, shallow oil pool in Canadian Natural's North Alberta core region has been developed exclusively with horizontal wells. This technology minimizes surface disturbance and environmental impact, reduces development costs and results in significantly greater well productivity in comparison to alternate techniques. Canadian Natural owns and operates more than 650 horizontal wells and three centralized treating facilities in the area. Although priced similarly to heavy oil, Canadian Natural's Pelican Lake oil production yields netbacks typical of medium oil due to the low operating costs. Operating costs of only $2.91/bbl were achieved in 2002 since water and sand production are negligible and wells are flowlined to central facilities. Canadian Natural is the largest oil producer in the Pelican Lake area.

The Company continues to develop portions of the pool with additional drilling but with limited undeveloped regions, drilling activity will be reduced. Primary production declines are expected, as shown by the 15% production decline from 2001 to 2002. The Company is forecasting a 6% recovery factor from primary production; however, the developed reservoir on Canadian Natural's leases contains approximately 3 billion barrels of oil in place, making it very attractive for secondary or tertiary recovery. Even modest improvements in recovery factors would have a significant impact on recoverable reserves and the Company's asset value. In pursuit of these reserves, Canadian Natural commenced a tertiary recovery pilot using emulsion injection in April 2002. Injection continues, however no significant response has been detected to date. Canadian Natural will examine the success of the current emulsion flood and compare results with a proposed waterflood project to determine the optimal enhanced recovery strategy for commercial application.

With three billion barrels of oil in place, enhanced oil recovery processes will provide continued production and profitability at Pelican Lake.

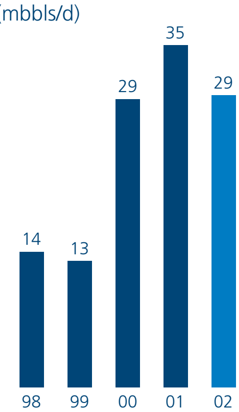
2002 ACHIEVEMENTS

- Production averaged 29,494 bbls/d, accounting for 7% of the Company's total boe production;
- Drilled 86 horizontal wells with a 100% success rate representing 19% of the Company's oil and natural gas well drilling activity;
- 11 stratigraphic test wells were drilled to delineate future drilling prospects;
- Commenced field testing of a tertiary recovery process with emulsion flooding; and
- Completed design and application for a waterflood project to be implemented in early 2003.

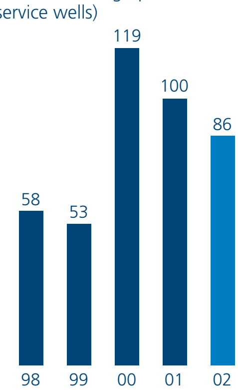
2003 PLANS

- Drill 40 horizontal wells;
- Drill 10 stratigraphic wells;
- Drill a horizontal observation well to assist in the continued evaluation of the emulsion injection pilot;
- Implement a waterflood project to test an alternative recovery technique; and
- Allocate $64 million to exploitation and development.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



Primary Heavy Oil – North America

Canadian Natural is one of the largest heavy oil producers in North America. The Company's growth of heavy oil production has been achieved through drilling, as well as strategic, synergistic acquisitions. Canadian Natural dominates production and operations within the Bonnyville primary producing area in the North Alberta core region. This dominance allows the Company to minimize capital by conducting large scale drilling and development programs. Operating costs are also minimized by owning and operating central treating facilities and maximizing their utilization.

Heavy oil in the Company's North Alberta core region is produced using primary production mechanisms from shallow, low-risk, multi-zone horizons. This leads to low finding and development costs, exceptional drilling success rates and many subsequent recompletion opportunities. The region is also natural gas prone and frequently heavy oil development drilling will lead to synergistic shallow natural gas pool discoveries.

Canadian Natural continues to have significant heavy oil drilling programs and when heavy oil prices are high, the Company has the ability and location inventory that allows it to rapidly increase drilling activity. In 2002 the Company had originally budgeted to drill 21 heavy oil wells but due to high commodity prices, the program was increased to 153 wells. This flexibility allows Canadian Natural to achieve earlier payout of the drilling projects and significantly improve the return on capital.

The Company is one of the dominant producers of heavy oil in North America. Control of infrastructure, a focus on operating costs, and prudent capital investment have created superior recycle ratios for Canadian Natural's heavy oil.

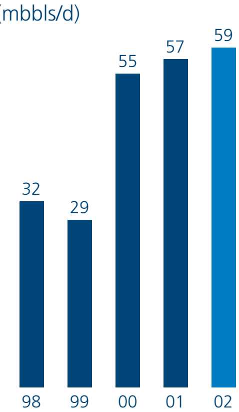
2002 ACHIEVEMENTS

- Production averaged 58,778 bbls/d, a 4% increase over 2001 production, and accounted for 14% of the Company's total boe production;
- Drilled 153 wells with a 99% success rate, representing 34% of the Company's oil and natural gas well drilling activity;
- 220 wells were recompleted to access secondary producing horizons; and
- $120 million was spent on synergistic acquisitions within core regions.

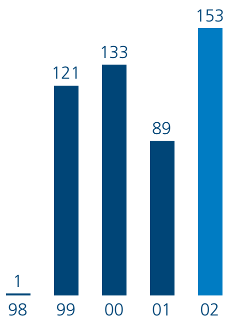
2003 PLANS

- Drill 265 wells;
- Recomplete 290 wells;
- Implement casing gas conservation on 140 wells;
- Increase the capacity of the Company owned and operated ECHO pipeline system to 72 mbbls/d, to increase the Company's volume throughput; and
- Allocate $198 million to exploration and development opportunities.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/
service wells)



review of assets

Thermal Heavy Oil – North America

The Company is the second largest producer of oil recovered by thermal processes in Canada and currently operates three thermal projects:

- Primrose: The Company produces from horizontal wells utilizing the cyclic steam stimulation ("CSS") process for oil recovery. The 350 active horizontal wells reduce capital costs, improve well productivity and minimize surface disturbance in comparison to alternative techniques. Regulatory approval for the expansion of operations at Primrose was obtained during 2002. This approval allows for the remaining low-pressure wells to be converted to high-pressure steaming and for the development of a new project area adjacent to the existing project. Development of the new project area is projected to commence in 2003 to 2005.
- Burnt Lake: The Company continues to operate this steam assisted gravity drainage ("SAGD") project on lands immediately adjacent to Primrose. The SAGD test results will be used in conjunction with the Primrose CSS results to determine the optimum economic process for commercial development at this site.
- Tangleflags: This mature project utilizes the SAGD recovery process and has been in operation since 1988. Recoveries in the pool are approaching 60% of the original oil in place. Pool extensions continue to provide modest expansions to the project area.

The thermal projects at Primrose and Burnt Lake provide geologically proven, low-risk production with a reserve life in excess of 25 years.

Canadian Natural also has significant thermal opportunities on approximately 100,000 acres of undeveloped lands in the Fort McMurray area of Alberta. Initial delineation drilling has established excellent SAGD development potential with 2 billion barrels of recoverable oil on the Company's leases at Gregoire Lake, Kirby and Horizon.

2002 ACHIEVEMENTS

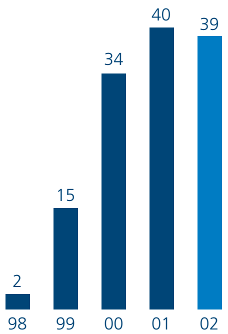
- Production averaged 39,458 bbls/d, remaining relatively unchanged from 2001, and accounted for 9% of the Company's total boe production;
- One production well was drilled and 136 stratigraphic test wells delineated future drilling prospects;
- Obtained regulatory approval to convert the Primrose field to high-pressure steam injection and for construction of a new production facility; and
- Converted 48 cyclic wells from low-pressure to high-pressure steam injection.

2003 PLANS

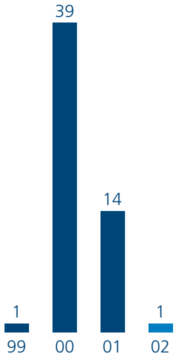
- Drill 46 horizontal wells and 12 vertical wells at Primrose for cyclic steaming. Production from these wells will commence in 2004;
- Continue conversion of existing horizontal wells to high-pressure cyclic steaming;
- Complete Engineering Design Study for Primrose North Plant Expansion; and
- Allocate $163 million to exploration and development opportunities.

Canadian Natural's thermal recovery operations provide an enormous reserve base that will provide continued, profitable growth through cost control and judicious planning of future expansions.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



Horizon Oil Sands Project

Canadian Natural owns and operates leases covering 117,000 acres in the Fort McMurray area of northern Alberta. The Horizon Oil Sands Project is located about 80 km north of Fort McMurray. Drilling to date indicates an estimated 16 billion barrels of bitumen in place, with approximately 6 billion barrels being recoverable under existing technologies.

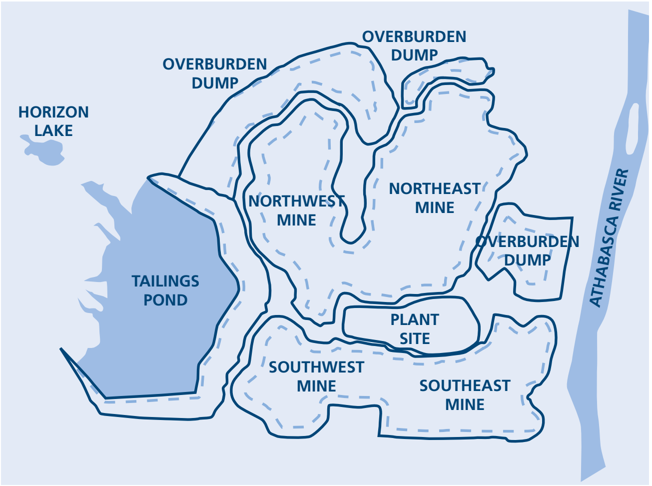
The Company has developed a project execution strategy that phases in the production from the project over a five-year period. First oil is expected in the first half of 2008 at a production rate of 110 mbbls/d of 34-36° API synthetic light crude oil ("SCO"). This represents an approximate six-month delay from prior expectations and is the result of uncertainty created through the Canadian Government's unclear implementation plan for the Kyoto Protocol. The second phase of production is expected in 2010 with an incremental 45 mbbls/d of SCO on stream. The third and final phase of development is expected to be completed in 2012 to bring total production to 232 mbbls/d of SCO.

Product marketing studies have been completed by Canadian Natural to forecast SCO sales potential and the associated pricing resulting from the production quantities of Horizon Project and other operator's oil sands project expansions. Current product pricing, capital and operating cost estimates for the project show an internal rate of return between 14% and 22% based upon long-term average WTI assumptions of US $18.00 to US $26.00 per barrel.

On June 28, 2002, Canadian Natural applied for regulatory approval to construct, operate and reclaim the Horizon Oil Sands Project. The regulatory review process is anticipated to conclude with approvals from the Energy and Utilities Board in late 2003. The project would then be in a position to commence site clearing and preconstruction and site preparation activities in 2004.

The Company's approach for this project is to extensively evaluate new technology options and pre-design the infrastructure prior to construction. Significant work has been completed in 2002 to assess alternatives in technology and improve definition of execution strategies for the engineering and construction phases of the project. Experience brought to the project from benchmarking with major constructors of world class projects, and the continued recruitment of experienced professionals, has enabled optimization of the project scope. In this way, Canadian Natural can increase cost certainty before significant activity begins. The Company plans full bitumen upgrading, however is still evaluating the optimum location for secondary upgrading facilities.

There are few projects in the world that can produce 232 mbbls/d of light sweet crude for over 40 years without production declines – right next door to the largest market in the world.



2002 ACHIEVEMENTS

- Completed the Horizon Oil Sands Project Scoping Study, documenting the project business concept development plan and preliminary engineering feasibility and technology assessments;
- Filed regulatory applications in June 2002. Regulatory review and discussions are underway, with approvals expected in 2003;
- Despite the six-month delay associated with the uncertainty for the Kyoto Protocol, the development and definition of project scope, execution strategies and facilities planning for the Design Basis Memorandum progressed significantly. Alternatives in technology and site footprint continued to be optimized, resulting in minor changes to plant layout;
- Continued improvements to execution strategy and planning through benchmarking with major constructors and world scale projects to benefit from their "lessons learned";
- Horizon Oil Sands Project staffing strategy was developed and completed;
- Approval received and work started on road construction to site; and
- Drilled 239 stratigraphic test wells to further delineate the ore body and confirm resource quality. Additionally, 54 test wells were drilled on the Horizon in-situ lease.

2003 PLANS

- Complete and publish the Design Basis Memorandum by mid year;
- An assessment by Independent Project Analysis Inc. for "Best Practical" rating of project preparedness, prior to moving to the next phase of engineering;
- Commence Engineering Design Specifications with targeted completion in spring 2004;
- Completion of road infrastructure to site;
- Begin site preparations for construction once regulatory approvals are given; and
- Drill 360 geological stratigraphic wells focusing on the mining area supplying the first ten years of production.

International Light Oil – Offshore West Africa

CÔTE D'IVOIRE

Canadian Natural has developed an excellent relationship with the Côte d'Ivoirian Government and has the necessary geological and operational expertise to exploit this strategic, underdeveloped basin. The Company maintains significant ownership interests in and operates five blocks encompassing 460 thousand acres. Canadian Natural plans to fully develop the Espoir and Baobab fields and target similar structures along the play fairway. Outlying structures can be drilled from and/or tied into existing facilities at low cost and provide significant economic upside through higher utilization of this infrastructure.

The Espoir field, where Canadian Natural has a 59% working interest, is currently producing to an FPSO from the lower productive zone, while the upper zone is being repressurized through water injection. In mid-2003, Canadian Natural expects to perforate this upper zone, increasing net production rates by up to 5 mbbls/d.

The adjacent Baobab field is under development with bids currently being sought for subsea infrastructure and FPSO facilities. Based upon a second successful well test in 2002, Canadian Natural estimates that 200 million barrels of recoverable oil within the structure. The Company is planning for an initial start-up date in 2005 at approximately 45 mbbls/d, increasing to 60 mbbls/d by 2006. Canadian Natural owns 61% of this field.

ANGOLA

Canadian Natural has an excellent relationship with the Government of Angola and its national oil company, Sonangol. This relationship and a solid operating history within Angola resulted in Canadian Natural being awarded operatorship and a 50% working interest in offshore Block 16. The Company obtained 3-D seismic over the entire Block 16 prior to obtaining title and has identified two high risk/high potential targets, Omba and Zenza. The Company is planning to drill the first of the prospects, Zenza, during the fourth quarter of 2003 as part of a two well commitment.

Canadian Natural continues with its development of the Espoir field offshore Côte d'Ivoire and is planning for the commercial development of the newly discovered Baobab pool. In Angola, the Company will be drilling a significant, high risk / high reward prospect in Block 16.

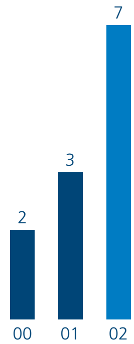
2002 ACHIEVEMENTS

- Production averaged 6,784 bbls/d, a 100% increase over 2001 production, and accounted for 2% of the Company's total boe production;
- Drilled three producing wells and one water injection well;
- Commenced production from Espoir field in February 2002;
- Drilled a second successful exploration well at Baobab and two unsuccessful exploration wells at Kossipo and Emien;
- Obtained 90% working interest and operatorship of Block CI-400 offshore Côte d'Ivoire on the same trend as the Baobob discovery;
- Terminated production at Kiame, Block 4 offshore Angola, having extended field life by one year;
- Participated (25% interest) in an unsuccessful exploration well offshore Angola Block 19; and
- Obtained operatorship and 50% working interest of offshore Block 16 in Angola.

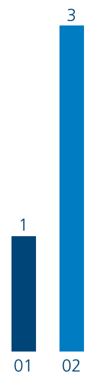
2003 PLANS

- Drill one water injector well in East Espoir;
- Commence development of West Espoir including the drilling of one well;
- Drill Acajou, satellite pool to Espoir;
- Initiate Baobab commercial development;
- Shoot 750 km^2 of 3-D seismic on blocks CI-400 and CI-40; and
- Drill Zenza prospect in offshore Angola Block 16.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



International Light Oil – North Sea

Canadian Natural's position in the North Sea was significantly strengthened in 2002 through the consolidation of interests on producing properties. In five separate transactions, Canadian Natural has now established three operating hubs that the Company operates with majority working interest. This provides a strong basis for future exploitation and near-pool exploration. In the North Sea the Company now operates 80% of its production and has an average working interest of 70%.

Canadian Natural's North Sea production is focused on three owned and operated, producing hubs:

- **Ninian Hub** – This hub consists of three platforms in the Northern North Sea with a combined well slot capacity of 109. Tied into the Ninian Hub are three Company operated fields, Ninian, Columba B/D/E and Lyell, and the non-operated Strathspey field. Crude oil is produced into the Sullom Voe Terminal where the Company has a 20% working interest. Good development potential exists on the 13 surrounding exploration blocks.
- **Murchison Hub** – The Canadian Natural owned and operated Murchison field is tied into this platform. The platform has a 34 well slot capacity and also produces into the Sullom Voe Terminal.
- **Banff / Kyle Hub** – The Banff and Kyle fields produce through subsea tie-backs into two separate FPSOs, one of which is operated by Canadian Natural.

Canadian Natural believes that the current environment within the North Sea is similar to that of western Canada in the early 1990's. The basin is mature and many of the major operators are reducing activity levels or looking at divestiture of properties. Canadian Natural also believes that the recent changes in the United Kingdom tax regime provides incentive for companies to evaluate their position in the North Sea. These changes effectively penalize producers through higher tax rates but provide some rewards to active drillers through quick write-off of capital expenditures. Companies in "harvest" mode are now motivated to re-evaluate positions and sell to exploitation oriented companies like Canadian Natural who are proactively pursuing such opportunities.

The Company has taken control of its North Sea assets through the strategic acquisition of partners' interests in its Northern North Sea operations. Canadian Natural now operates 80% of its North Sea production and has an average ownership interest of 70%.

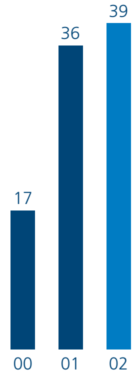
2002 ACHIEVEMENTS

- Production averaged 38,876 bbls/d, a 7% increase over 2001 production, and accounted for 9% of the Company's total boe production;
- Drilled five producing wells and one water injection well;
- $165 million was spent on synergistic acquisitions to consolidate North Sea ownership; and
- Assumed operatorship of Ninian, Murchison and Lyell fields in Northern North Sea.

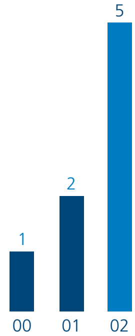
2003 PLANS

- Drill 16 platform development wells (including several with through tubing rotary drilling);
- Drill two wells from mobile units;
- Optimize waterflood at Ninian/Murchison; and
- Examine near-pool development opportunities near the Murchison platform.

Annual Production
(mbbls/d)



Successful Wells Drilled
(excludes stratigraphic test/ service wells)



management's discussion & analysis

Canadian Natural Resources Limited is a Canadian based senior independent energy company engaged in the acquisition, exploration, development, production, marketing and sale of oil and natural gas. The Company initiates, operates and maintains a large working interest in a majority of the prospects in which it participates. The Company's principal core areas of oil and natural gas operations are in the Western Canadian Sedimentary Basin, the United Kingdom sector of the North Sea and Offshore West Africa.

management's discussion & analysis

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in the Management's Discussion and Analysis for Canadian Natural Resources Limited (the "Company") may constitute forward-looking statements within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company believes, anticipates, expects, plans, estimates or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; foreign currency exchange rates; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the availability and cost of financing; the success of exploration and development activities; production levels; uncertainty of reserve estimates; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); site restoration costs; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2002. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation of Canadian GAAP to United States GAAP is included in note 16 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except when noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil to estimate relative energy content.

The following discussion details the Company's 2002 financial results compared to 2001 and 2000, including its capital program, and outlook for 2003.

OBJECTIVE AND STRATEGY

The Company's objective is to increase cash flow, net earnings, and oil and natural gas production and reserves through the development of its existing oil and natural gas properties and by the discovery and acquisition of new reserves. The Company accomplishes this by having a defined growth and value enhancement plan for each of its products and segments. The Company effectively allocates its capital by maintaining:

- Balance between its products, namely natural gas, light oil, Pelican Lake oil [(1)], primary heavy oil and thermal heavy oil;
- Balance between near-, mid- and long-term projects;
- Balance between acquisitions, exploitation and exploration; and
- Balance between sources of debt and a strong balance sheet.

Strategic acquisitions, such as the acquisition of Rio Alto Exploration Ltd. ("Rio Alto"), are a key component of the Company's strategy.

Cost control is central to the Company's strategy. By controlling costs consistently throughout all industry cycles, the Company is able to achieve continued growth. Cost control is attained by core area domination and by operating at a high working interest.

(1) Pelican Lake oil is 14-17° API oil, but receives medium quality crude netbacks due to exceptionally low operating costs and low royalty rates.

management's discussion & analysis

The year ended December 31, 2002 was another successful year in the execution of the Company's strategy. The highlights were:

- Acquired Rio Alto;
- Acquired North Sea properties that provide the Company with the level of operatorship and working interests in the North Sea necessary to effectively control costs;
- Commenced production from the Espoir field offshore Côte d'Ivoire;
- Successfully delineated the Baobab field located offshore Côte d'Ivoire;
- Received government approval for development of the Baobab field;
- Received regulatory approval for high-pressure steaming at Primrose, Alberta;
- Submitted regulatory application for the Horizon Oil Sands Project ("Horizon Project");
- Signed a Production Sharing Agreement for Block 16, offshore Angola and Block CI-400 offshore Côte d'Ivoire; and
- Successfully issued public debt to balance our sources of debt.

ACQUISITION OF RIO ALTO

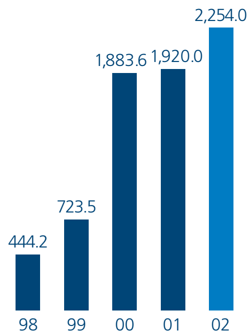
The Company paid cash of $850.0 million and issued 10,008,218 common shares to acquire all of the issued and outstanding common shares of Rio Alto by way of a plan of arrangement. This was a strategic acquisition by the Company as it strengthened the Company's natural gas production in North America and added a new natural gas core region in Northwest Alberta that will provide the opportunity for significant future natural gas volumes. The Rio Alto acquisition is included in the results of operations commencing July 1, 2002.

CASH FLOW AND NET EARNINGS

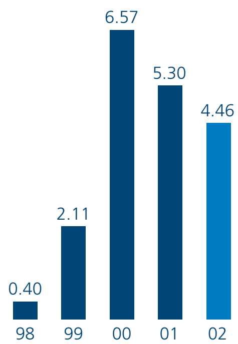
Financial Highlights ($ millions, except per share amounts)	**2002**	2001[(1)]	2000[(1)]
Revenue	**$ 4,083.2**	$ 3,588.8	$ 3,260.6
Cash flow from operations attributable to common shareholders [(2)]	**$ 2,254.0**	$ 1,920.0	$ 1,883.6
Per common share – basic	**$ 17.63**	$ 15.83	$ 16.14
– diluted	**$ 16.99**	$ 15.23	$ 15.64
Net earnings attributable to common shareholders [(3)]	**$ 569.8**	$ 642.6	$ 767.1
Per common share – basic	**$ 4.46**	$ 5.30	$ 6.57
– diluted	**$ 4.31**	$ 5.17	$ 6.39
Business combinations	**$ 2,393.2**	$ –	$ 1,687.3
Capital expenditures, net of dispositions	**$ 1,676.2**	$ 1,884.5	$ 1,136.0

(1) Restated for change in accounting policy (see consolidated financial statements – note 2) and to conform to current year presentation.
(2) After dividend on preferred securities.
(3) After dividend and revaluation of preferred securities.

Cash Flow From Operations Attributable to Common Shareholders ($ millions)

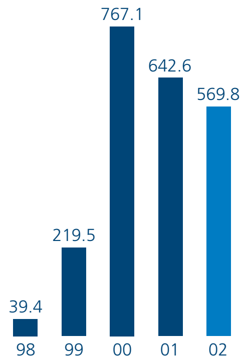


Net Earnings per Share Attributable to Common Shareholders* ($)



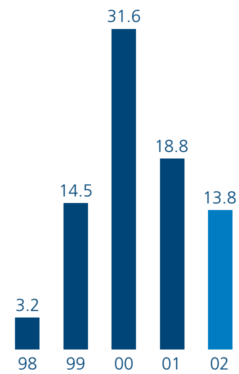
*Restated for change in accounting policy

Net Earnings Attributable to Common Shareholders* ($ millions)



*Restated for change in accounting policy

Return on Average Common Shareholder's Equity* (%)



*Restated for change in accounting policy

Cash flow from operations attributable to common shareholders increased 17% to $2,254.0 million ($17.63 per common share), up from $1,920.0 million ($15.83 per common share) in 2001 and $1,883.6 million ($16.14 per common share) in 2000. The increase in cash flow resulted primarily from increased production volumes offset by lower natural gas prices. In 2002, the Company's average price per barrel of oil and liquids increased to $29.76 from $24.31 in 2001 (2000 – $29.99). Production volumes increased 17% to 420,722 boe/d from 359,347 boe/d in 2001 (2000 – 305,987 boe/d).

Net earnings attributable to common shareholders decreased 11% in 2002 to $569.8 million, down from $642.6 million in 2001 and down from $767.1 million in 2000. The decrease in net earnings resulted from the natural gas weighted acquisition of Rio Alto, higher depletion, depreciation and amortization costs and increased future income tax expense.

Operating Highlights	2002	2001 (1)	2000 (1)
Oil and liquids ($/bbl, except daily production)			
Daily production (bbls/d)	**215,335**	206,323	173,591
Sales price	**$ 29.76**	$ 24.31	$ 29.99
Royalties	**3.16**	2.17	3.05
Production expense	**8.45**	7.64	6.84
Netback	**$ 18.15**	$ 14.50	$ 20.10
Natural gas ($/mcf, except daily production)			
Daily production (mmcf/d)	**1,232**	918	794
Sales price	**$ 3.76**	$ 5.16	$ 4.53
Royalties	**0.78**	1.25	1.08
Production expense	**0.57**	0.51	0.44
Netback	**$ 2.41**	$ 3.40	$ 3.01
Barrel of oil equivalent ($/boe, except daily production)			
Daily production (boe/d)	**420,722**	359,347	305,987
Sales price	**$ 26.25**	$ 27.15	$ 28.77
Royalties	**3.91**	4.42	4.51
Production expense	**5.99**	5.69	5.02
Netback	**$ 16.35**	$ 17.04	$ 19.24

(1) Restated to conform to current year presentation.

REVENUE

Product Prices

	2002	2001	2000
Oil and liquids ($/bbl)			
North America	**$ 27.04**	$ 21.00	$ 28.15
North Sea	**$ 39.79**	$ 38.66	$ 44.61
Offshore West Africa	**$ 40.10**	$ 33.57	$ 45.77
Company average	**$ 29.76**	$ 24.31	$ 29.99
Natural gas ($/mcf)			
North America	**$ 3.78**	$ 5.19	$ 4.53
North Sea	**$ 2.75**	$ 2.51	$ 3.66
Offshore West Africa	**$ 4.82**	$ –	$ –
Company average	**$ 3.76**	$ 5.16	$ 4.53
Percentage of revenue (excluding midstream revenue)			
Oil and liquids	**58.1%**	51.5%	59.2%
Natural gas	**41.9%**	48.5%	40.8%

Analysis of Changes in Revenue (excluding midstream operations)

($ millions)	2000	Changes due to Volumes	Changes due to Prices	2001	**Changes due to Volumes**	**Changes due to Prices**	**2002**
North America							
Oil and liquids	$ 1,591.0	$ 122.5	$ (434.1)	$ 1,279.4	**$ 23.0**	**$ 373.4**	**$ 1,675.8**
Natural gas	1,314.1	183.3	220.0	1,717.4	**565.1**	**(621.0)**	**1,661.5**
	2,905.1	305.8	(214.1)	2,996.8	**588.1**	**(247.6)**	**3,337.3**
North Sea							
Oil and liquids	280.8	309.5	(78.5)	511.8	**37.0**	**16.3**	**565.1**
Natural gas	2.0	14.3	(5.1)	11.2	**13.6**	**2.5**	**27.3**
	282.8	323.8	(83.6)	523.0	**50.6**	**18.8**	**592.4**
Offshore West Africa							
Oil and liquids	34.6	22.1	(15.1)	41.6	**41.5**	**16.2**	**99.3**
Natural gas	–	–	–	–	**2.2**	**–**	**2.2**
	34.6	22.1	(15.1)	41.6	**43.7**	**16.2**	**101.5**
Total							
Oil and liquids	1,906.4	454.1	(527.7)	1,832.8	**101.5**	**405.9**	**2,340.2**
Natural gas	1,316.1	197.6	214.9	1,728.6	**580.9**	**(618.5)**	**1,691.0**
	$ 3,222.5	$ 651.7	$ (312.8)	$ 3,561.4	**$ 682.4**	**$ (212.6)**	**$ 4,031.2**

Oil and natural gas revenue rose 13% to $4,031.2 million from $3,561.4 million in 2001 (2000 – $3,222.5 million). In 2002, 17% of the Company's oil and natural gas revenue was generated outside of North America (2001 – 16%, 2000 – 10%), with the North Sea accounting for 15% of these revenues, in both 2002 and 2001 (2000 – 9%) and Offshore West Africa accounting for 2%, up from 1% in 2001 (2000 – 1%). Revenue from the sale of natural gas accounted for 42% of oil and natural gas revenue, down from 49% in 2001 (2000 – 41%).

Oil and liquids pricing realized by the Company is directly correlated with world oil pricing and heavy oil differentials. The realized oil and liquids price earned by the Company in 2002 increased 22% to average $29.76 per bbl for the year, up from $24.31 per bbl in 2001 (2000 – $29.99 per bbl). World oil prices were low in the beginning of 2002 but increased throughout the year due to supply and demand fundamentals, general market uncertainty surrounding tension in the Middle East, and disruptions in the supply of oil from Venezuela. The West Texas Intermediate ("WTI") oil price increased 1% to average US $26.11 per bbl, up from US $25.91 per bbl in 2001 (2000 – US $30.20 per bbl). During the same time, the heavy oil differential averaged US $6.50 per bbl, down from US $10.73 per bbl in 2001 (2000 – US $8.23 per bbl). Heavy oil differentials were lower than the historical 10-year average 30% discount to WTI pricing due to a lower supply of heavy oil from western Canadian producers. The higher heavy oil differentials experienced in 2001 were affected by the temporary shutdown of a heavy oil refinery in the US mid-west and reduced demand for heavy oil.

Natural gas prices decreased 27% to average $3.76 per mcf, down from $5.16 per mcf in 2001 (2000 – $4.53 per mcf), due to lower demand and higher storage levels in the first half of 2002. Prices in 2001 were impacted by the increased demand for natural gas due to cold winter temperatures, low inventory levels, increased natural gas-fired power generation and increased export capacity. AECO prices averaged $4.07 per mmbtu in 2002 compared to $6.25 per mmbtu in the year 2001 (2000 – $5.02 per mmbtu). NYMEX natural gas prices per mmbtu averaged US $3.25 in 2002 compared to US $4.38 in 2001 (2000 – $3.91).

The Company uses certain financial instruments to protect against the downside commodity prices received on the sale of certain oil and natural gas production and to protect its capital program. The price realized from the sale of oil was reduced by $1.46 per bbl in 2002 compared to an increase of $0.86 per bbl in 2001 (2000 – reduction of $1.89 per bbl), as a result of the financial instruments. The price realized from the sale of natural gas was reduced by $0.01 per mcf in 2002 compared to a reduction of $0.29 per mcf in 2001 (2000 – reduction of $0.39 per mcf), as a result of the financial instruments.

As part of its overall risk management program, the Company has entered into "costless collars" on a portion of its oil and natural gas production. These financial instruments are summarized in note 12 to the consolidated financial statements.

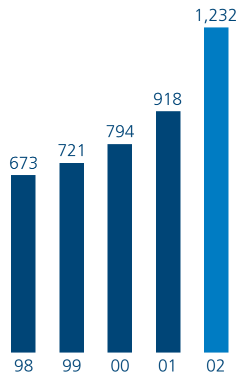
DAILY PRODUCTION

	2002	2001	2000
Oil and liquids (bbls/d)			
North America	**169,675**	166,675	154,331
North Sea	**38,876**	36,252	17,195
Offshore West Africa	**6,784**	3,396	2,065
Total	**215,335**	206,323	173,591
Natural gas (mmcf/d)			
North America	**1,204**	906	793
North Sea	**27**	12	1
Offshore West Africa	**1**	–	–
Total	**1,232**	918	794
Product mix			
Light oil and liquids	**20.8%**	20.7%	18.1%
Pelican Lake oil	**7.0%**	9.7%	9.4%
Primary heavy oil	**14.0%**	15.8%	18.0%
Thermal heavy oil	**9.4%**	11.2%	11.2%
Natural gas	**48.8%**	42.6%	43.3%

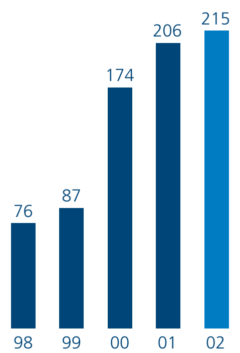
The Company's daily oil and liquids production increased 4% to average 215,335 bbls in 2002 from 206,323 bbls in 2001 (2000 – 173,591 bbls). Oil and liquids production increased for all segments from the year ended December 31, 2001. The increase in North American production is attributable to additional heavy oil drilling activity and property acquisitions in the Company's core operating regions. Oil production in the North Sea increased as a result of the acquisition of additional interests in the northern sector of the North Sea in 2002. Offshore West Africa oil production increased from 2001 as a result of production commencing from the Company's operated Espoir field, located offshore Côte d'Ivoire, in February 2002.

Natural gas continues to represent the Company's largest product offering, accounting for nearly 49% of the Company's total production in 2002 compared to 43% of total production in both 2001 and 2000. North America accounts for over 98% of the Company's natural gas production in 2002 and 2001 (2000 – 100%). Daily natural gas production increased 34% to 1,232 mmcf from 918 mmcf in 2001 (2000 – 794 mmcf). Natural gas production increased from the comparable periods due to development of the Ladyfern field and the 2002 mid-year acquisition of Rio Alto. Natural gas production from Rio Alto properties averaged 376 mmcf/d over the last half of 2002. The Ladyfern field averaged 168 mmcf/d of natural gas production during 2002, up from 40 mmcf/d in 2001. Natural gas production increased in the North Sea due to the acquisition of additional interests in the Banff and Kyle fields.

Natural Gas Production
(mmcf/d)



Crude Oil and NGLs Production
(mbbls/d)



ROYALTIES

	2002	2001	2000
Oil and liquids ($/bbl)			
North America	**$ 3.42**	$ 2.22	$ 3.17
North Sea	**$ 2.30**	$ 2.10	$ 2.40
Offshore West Africa	**$ 1.35**	$ 0.93	$ –
Company average	**$ 3.16**	$ 2.17	$ 3.05
Natural gas ($/mcf)			
North America	**$ 0.80**	$ 1.26	$ 1.08
Offshore West Africa	**$ 0.15**	$ –	$ –
Company average	**$ 0.78**	$ 1.25	$ 1.08
Company average ($/boe)	**$ 3.91**	$ 4.42	$ 4.51
Percentage of revenue (excluding financial instruments)			
Oil and liquids	**10.1%**	9.3%	9.6%
Natural gas	**20.8%**	22.8%	22.0%

Oil and liquids royalties in North America increased to $3.42 per bbl, up from $2.22 per bbl in 2001 (2000 – $3.17 per bbl), due to changes in oil prices. Oil and liquids royalties in North America increased as a percentage of revenue as a result of certain primary and thermal heavy oil projects that were subject to a lower royalty structure reaching payout and becoming subject to higher government royalty rates. The majority of the Company's oil sands projects continue to benefit from reduced royalty rates as a result of the Alberta program to promote development of oil sands resources, which provides a reduced royalty rate until an oil sands project recovers its capital costs. In 2002, North Sea oil royalties increased to $2.30 per bbl from $2.10 per bbl in 2001 (2000 – $2.40 per bbl). The increase per barrel and as a percentage of revenue is due to the acquisition of additional interests in the royalty paying Ninian, Murchison and Columba fields. In late November 2002, it was announced that royalties in the North Sea would be eliminated effective January 1, 2003. Offshore West Africa oil royalties increased from the prior year due to the Espoir field commencing production in February 2002. In 2001, the Kiame field in Angola was the only field on production and was on royalty holiday for a portion of that year.

Natural gas royalties for the Company decreased to $0.78 per mcf for the year 2002, down from $1.25 per mcf in 2001 (2000 – $1.08 per mcf), due to the overall decrease in natural gas prices. North American natural gas royalties are sensitive to price changes and increased as a percentage of revenue in 2001 due to the higher sales prices received. Natural gas royalties as a percentage of revenue decreased to 20.8% in 2002 from 22.8% of revenue in 2001 (2000 – 22.0%) due to lower average natural gas prices. In the North Sea, the Company's natural gas production is derived from the non–royalty paying Banff and Kyle fields.

PRODUCTION EXPENSE

	2002	2001 (1)	2000 (1)
Oil and liquids ($/bbl)			
North America	**$ 6.73**	$ 7.05	$ 6.45
North Sea	**$ 15.06**	$ 9.00	$ 8.66
Offshore West Africa	**$ 13.63**	$ 21.77	$ 20.41
Company average	**$ 8.45**	$ 7.64	$ 6.84
Natural gas ($/mcf)			
North America	**$ 0.55**	$ 0.50	$ 0.44
North Sea	**$ 1.53**	$ 0.94	$ 0.79
Offshore West Africa	**$ 1.81**	$ –	$ –
Company average	**$ 0.57**	$ 0.51	$ 0.44
Company average ($/boe)	**$ 5.99**	$ 5.69	$ 5.02

(1) Restated to conform to current year presentation.

The decrease in 2002 North America oil and liquids production expense to $6.73 per bbl from $7.05 per bbl in 2001 (2000 – $ 6.45 per bbl) is primarily attributable to the decrease in natural gas prices. Natural gas is used to produce steam to heat the thermal oil formations to facilitate extraction in the Primrose area of Alberta. Production expense in 2001 was higher due to higher fuel and power costs incurred during the first half of the year. North Sea oil production expense increased in 2002 to $15.06 per bbl from $9.00 per bbl in 2001 (2000 – $8.66 per bbl), due to costs incurred as a result of the planned maintenance shutdowns of the Ninian North and Ninian Central platforms during the third quarter of 2002. Production expense in the North Sea also increased in 2002 as a result of costs incurred to rectify a natural gas pipeline blockage at Kyle experienced in the second quarter of 2002, and because the Columba B and D fields reached a production milestone during 2001, thereby giving rise to higher tariff rates on a go-forward basis. Offshore West Africa oil production expense decreased to $13.63 per bbl from $21.77 per bbl in 2001 (2000 – $ 20.41 per bbl) as a result of production ceasing from the higher production expense Kiame field and as a result of production commencing from the Espoir field.

Natural gas production expense for the year 2002 increased to $0.57 per mcf from $0.51 per mcf in 2001 (2000 – $0.44 per mcf), due to increased gathering and processing charges and increased toll rates on Ladyfern production in the first half of 2002.

MIDSTREAM

($ millions)	**2002**	2001	2000
Revenue	**$ 52.0**	$ 27.4	$ 38.1
Operating costs	**14.1**	11.2	8.7
Operating cash flow	**37.9**	16.2	29.4
Depreciation	**7.6**	3.8	1.8
Segment earnings before taxes	**$ 30.3**	$ 12.4	$ 27.6

The Company's midstream assets consist of the 100% owned and operated ECHO pipeline, the 15% interest in the Cold Lake pipeline system, the 62% interest in the operated Pelican Lake pipeline, and the 50% interest in the 84 megawatt co-generation system located in the Primrose area. The midstream pipeline assets allow the Company to transport its own production volumes as well as earn third party revenue from excess capacity. The Company transports approximately 82% of its heavy oil through its pipelines to the international mainline liquid pipelines. These midstream assets enhance the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

The increase in operating cash flow and segment earnings before taxes in 2002 was due to the expansion of the ECHO pipeline, as well as the increased interest in the Pelican Lake pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. The increased pipeline revenues were partially offset by a decline in electricity revenue received from the sale of excess electricity from the Company's cogeneration system to the Alberta Power Pool.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

($ millions, except per boe amounts)	**2002**	2001	2000
North America	**$ 1,032.8**	$ 747.1	$ 585.9
North Sea	**193.3**	129.0	54.4
Offshore West Africa	**80.5**	23.9	2.5
Expense	**$ 1,306.6**	$ 900.0	$ 642.8
$/boe	**$ 8.51**	$ 6.86	$ 5.73

(1) DD&A excludes midstream operations.

Depletion, depreciation and amortization ("DD&A") increased in total and per boe to $1,306.6 million or $8.51 per boe from $900.0 million or $6.86 per boe in 2001 (2000 – $642.8 million or $5.73 per boe). This increase was due to the higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with Rio Alto, and future abandonment costs associated with the acquisition of additional interests in the North Sea. DD&A was further increased in 2002 as a result of the Company's decision to exit from its interests in Block 19, Angola, and from the Aje field, Nigeria. The decision to exit from Block 19, Angola was made after a technical review of the results of the Mariposa well where the Company held a 25% non-operated working interest. The decision to exit from the Aje field was based on a reinterpretation of seismic that showed the structural closures were greatly reduced from previous expectations. The reduction in likely oil-in-place and associated risk meant that the project failed to meet the Company's economic threshold. The Company charged all related capitalized costs in those countries, totaling $51 million, to DD&A during the second quarter of 2002.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts)	**2002**	2001	2000
Gross cost	**$ 147.2**	$ 109.9	$ 67.8
$/boe	**$ 0.96**	$ 0.84	$ 0.61
Net expense	**$ 61.3**	$ 37.6	$ 27.2
$/boe	**$ 0.40**	$ 0.29	$ 0.25

Gross administration expense increased to $0.96 per boe from $0.84 per boe in 2001 (2000 – $0.61 per boe) mainly due to higher staffing levels associated with the growth in production and the expanding asset base. Gross administration expense also increased as a result of the higher costs related to the assumption of operatorship of certain fields in the North Sea and the cost of relocating the majority of the Company's UK operations to Aberdeen during the fourth quarter 2002. Net administration expense, after operator recoveries and capitalized overhead relating to exploration and development in the North Sea and Offshore West Africa as well as the Horizon Project, increased to $0.40 per boe in 2002 from $0.29 per boe in 2001 (2000 – $0.25 per boe), due to the higher staffing levels and expanding asset base.

INTEREST EXPENSE

	2002	2001	2000
Interest expense ($ millions)	**$ 158.9**	$ 137.8	$ 162.3
$/boe	**$ 1.03**	$ 1.05	$ 1.45
Average effective interest rate	**4.5%**	5.4%	6.4%

Interest expense increased in total to $158.9 million in 2002 from $137.8 million in 2001 (2000 – $162.3 million), due to higher average outstanding debt levels as a result of the acquisition of Rio Alto and other property acquisitions. Interest expense was consistent with 2000 as the overall increase in debt levels in the last half of 2002 was offset by the lower cost of borrowing. The impact of the higher debt levels was partially offset by the lower overall cost of borrowing of 4.5% in 2002 from 5.4% in 2001 (2000 – 6.4%). Interest expense per boe remained consistent at $1.03 per boe in 2002 compared to $1.05 per boe in 2001 as the higher interest expense was offset by increased production, but decreased from 2000 due to the increase in production and the lower cost of borrowing. The Company continues to benefit from the lower short-term interest rates as its fixed-rate debt accounts for only 40% of total debt outstanding (after interest rates swaps, see note 12 to the consolidated financial statements) as at December 31, 2002 (2001 – 21%, 2000 – 23%).

FOREIGN EXCHANGE

($ millions)	**2002**	2001[1]	2000[1]
Realized foreign exchange loss (gain)	**$ 3.4**	$ (1.3)	$ (0.2)
Unrealized foreign exchange (gain) loss	**(35.1)**	64.1	16.1
	$ (31.7)	$ 62.8	$ 15.9

(1) Restated for change in accounting policy (see consolidated financial statements – note 2).

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. The new standard requires foreign exchange gains and losses on the Company's US dollar denominated debt to be expensed immediately rather than deferring and amortizing the gains and losses over the term of the related debt. The change in accounting policy was applied retroactively and foreign exchange losses for the year ended December 31, 2001 were increased by $48.1 million (2000 – $13.5 million). The majority of the foreign exchange amounts are due to the translation of the US dollar denominated debt.

The Company's US dollar denominated debt increased to US $1,968.0 million, up from US $899.0 million in 2001 and US $509.0 million in 2000. The increase in the US dollar denominated debt in 2002 was due to the following issuances:

- US $400 million of US dollar debt securities, maturing January 15, 2032, and bearing interest at 7.20%;
- US $350 million of US dollar debt securities, maturing October 1, 2012, and bearing interest at 5.45%; and
- US $350 million of US dollar debt securities, maturing June 30, 2033, and bearing interest at 6.45%.

US dollar denominated debt represented 76% of total debt outstanding at December 31, 2002 (2001 – 53%, 2000 – 31%). Due to the greater amount of US dollar denominated debt outstanding, the Company's net earnings were more affected by the fluctuations in the Canadian dollar. The US/Canadian dollar exchange rate fluctuated throughout 2002 due to economic and political uncertainties. The Canadian dollar averaged US $0.637 in 2002, down from US $0.646 in 2001 (2000 – US $0.673).

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company, effective July 1, 2002, designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

TAXES

($ millions, except for tax rates)	2002	2001	2000
Taxes other than income tax			
Current	$ 53.4	$ 69.3	$ 57.1
Deferred	9.5	(0.2)	(7.6)
Total	$ 62.9	$ 69.1	$ 49.5
Current income tax			
North Sea	$ (19.6)	$ 61.8	$ 33.7
Offshore West Africa	6.0	–	–
North America – Large Corporations Tax	21.2	15.1	14.7
Total	$ 7.6	$ 76.9	$ 48.4
Future income tax	$ 401.0	$ 282.5	$ 464.0
Effective income tax rate	41.6%	35.4%	39.9%

Taxes other than income tax consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income after certain deductions including abandonment expenditures. Taxes other than income tax decreased to $62.9 million or $0.41 per boe in 2002 from $69.1 million or $0.53 per boe in 2001 (2000 – $49.5 million or $0.44 per boe). The decrease in taxes other than income taxes was mainly due to the lower netback earned in the North Sea as a result of increased production costs. Taxes other than income taxes increased from the year 2000 due to a full year of production from the North Sea properties acquired in the Ranger Oil Limited ("Ranger") acquisition. North Sea PRT accounts for $51.1 million or $0.33 per boe in 2002 compared to $59.1 million or $0.45 per boe in 2001 (2000 – $33.3 million or $0.29 per boe).

In 2002, there was a recovery of current income tax in the North Sea of $19.6 million or $0.13 per boe compared to an income tax expense of $61.8 million or $0.47 per boe in 2001 (2000 – $33.7 million or $0.30 per boe). The decrease in the current income tax expense was partly due to the decision by the UK Government to increase the first year capital allowance rate for plant and machinery expenditures to 100% from the previous rate of 25%. The recovery of current income tax also resulted from the settlement of certain outstanding matters from prior years. Offshore West Africa current income tax expense increased from the prior year due to the commencement of operations at the Espoir field located offshore Côte d'Ivoire in February 2002. The Company did not incur any cash Canadian federal income taxes in 2002. It is anticipated that, based on the current availability of $3.1 billion of tax pools in Canada at the end of 2002 and the current pricing, the Company could be cash taxable in Canada in 2003. The Company is liable for the payment of federal Large Corporations Tax ("LCT"). LCT increased to $21.2 million or $0.14 per boe from $15.1 million or $0.11 per boe (2000 – $14.7 million, $0.13 per boe) due to the higher taxable capital base as a result of increased debt levels and shareholders' equity associated with the acquisition of Rio Alto.

The Company's future income tax provision for 2002 increased to $401.0 million ($2.61 per boe) from $282.5 million ($2.15 per boe) in 2001 (2000 – $464.0 million or $4.14 per boe) due to the increase in net earnings before tax. Future income tax expense for the year ended December 31, 2002 also increased over the prior year due to the introduction in the UK of a 10% supplementary charge on profits from North Sea oil and natural gas production. The supplementary charge is in addition to the current corporate tax rate of 30% and excludes any deduction for financing costs. As a result of this additional charge, the future income tax liability in the North Sea was increased by $34 million. The increase in the North Sea future income tax liability was partially offset by a $26 million decrease in the North American future income tax liability as a result of a reduction in a Canadian province's corporate income tax rate in the second quarter of 2002. In 2001, the North American future income tax liability was reduced by $63 million as a result of reductions in Canadian provinces' corporate income tax rates. Future income taxes also increased in 2002 because of the increased capital allowance rates in the North Sea, resulting in a lower current tax expense and a higher future income tax expense. Future income taxes in 2000 were higher due to higher product netbacks and higher current income tax rates in Canada.

The Company's effective tax rate increased to 41.6% in 2002 from 35.4% in 2001 (2000 – 39.9%). The increase is a result of the introduction of the 10% supplementary charge on profits from North Sea oil and natural gas production and the reductions in certain Canadian provinces' corporate income tax rates during 2001.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	2002	2001 [1]	2000 [1]
Working capital deficit	**$ 13.8**	$ 5.6	$ 77.3
Long-term debt	**4,074.0**	2,669.2	2,454.5
Net debt	**$ 4,087.8**	$ 2,674.8	$ 2,531.8
Shareholders' equity			
Preferred securities	**$ 126.4**	$ 127.4	$ 119.9
Share capital	**2,303.8**	1,698.3	1,692.6
Retained earnings	**2,414.3**	1,908.5	1,390.6
Foreign currency translation adjustment	**23.6**	72.8	–
Total	**$ 4,868.1**	$ 3,807.0	$ 3,203.1
Debt to cash flow [2]	**1.8x**	1.4x	1.3x
Debt to book capitalization	**45.6%**	41.2%	43.4%
Debt to market capitalization	**38.9%**	34.9%	32.1%
After tax return on average common shareholders' equity [2]	**13.8%**	18.8%	31.6%
After tax return on average capital employed [2]	**8.9%**	12.0%	18.1%

(1) Restated for change in accounting policy (see consolidated financial statements – note 2).
(2) Based on trailing 12-month period and does not include amounts related to acquired assets for the six-month period prior to June 30, 2002.

The Company recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment.

LONG-TERM DEBT

Long-term debt at December 31, 2002 amounted to $4,074 million and reflected a 1.8x debt to cash flow ratio and a debt to book capitalization of 45.6%. These ratios are within the Company's guidelines for balance sheet management.

At December 31, 2002 the Company had:

- Approximately $1.3 billion of available unused bank credit facilities;
- A fixed/floating interest rate mix of 40%/60%;
- An overall average cost of borrowing of approximately 4.5%;
- 76% of borrowings denominated in US dollars; and
- 76% of total long-term debt is non-bank based borrowing with an average maturity of 15.6 years.

During 2002, the Company issued US dollar debt securities and used the proceeds from the issuances to repay bank indebtedness. In January 2002, the Company issued US $400 million of 30-year US dollar debt securities maturing January 15, 2032, bearing interest at 7.20%. In September 2002, the Company issued US $350 million of ten-year US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350 million of 30-year US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Subsequent to these issuances, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate (see consolidated financial statements – note 12). The Company has US $300 million remaining on a US $1 billion shelf prospectus filed on August 16, 2002 that allows for the issue of debt securities until September 2004. In addition, the Company maintains a shelf prospectus in Canada for the offering of up to $1 billion of medium-term notes in Canada. If issued, these securities will bear interest as determined at the date of issuance. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in the fixed to floating interest rate mix.

The ratings of the Company's debt securities and its relationships with principal banks are extremely important to the Company as it continues to expand and grow. Hence, the Company's management will continually undertake to strengthen its balance sheet and financial position. The Company's debt securities are rated "Baa1" by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation and "BBB(high)" by Dominion Bond Rating Services Limited.

As at December 31, 2002, the Company had unsecured bank credit facilities of $2,275 million compared to $1,840 million at the close of 2001 (2000 – $2,800 million). During 2002, the Company repaid and cancelled a $725 million credit and term loan facility and a US $150 million credit and term loan facility. At December 31, 2002, the Company had approximately $1.3 billion of unutilized bank credit lines available to it, in addition to funds that are available through the Company's Canadian and US shelf prospectuses.

SHARE CAPITAL

The Company issued 10.0 million common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto. A further 2.5 million shares were issued from the exercise of stock options throughout 2002 for proceeds of $82.1 million. In 2001, 1.5 million common shares from the exercise of stock options and warrants were issued for proceeds of $45.5 million. In 2000, 3.2 million common shares were issued from the exercise of stock options for proceeds of $65.3 million and 7.6 million common shares were issued at an attributed value of $358.0 million as part of the consideration to acquire Ranger.

During 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2.3 million. The value of the common shares was determined based on the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the allotment.

In January 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange. As at January 21, 2002, the Company had purchased 2,537,800 common shares, of the allowable 6,114,726 common shares for a total cost of $113.3 million. In January 2002, the Company renewed its Normal Course Issuer Bid. No common shares were purchased under the renewed Normal Course Issuer Bid in the period ended January 23, 2003.

In January 2003, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,692,799 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As at February 26, 2003, 175,600 common shares had been purchased under the Normal Course Issuer Bid for a total cost of $8.3 million.

In January 2001, the Company announced a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year. In February 2002, the Board of Directors increased the Company's regular quarterly dividend to $0.125 per common share. In February 2003, the Board of Directors declared a 20% increase in the regular quarterly dividend to $0.15 per common share, or $0.60 per share per annum, commencing with the April 1, 2003 payment.

The Company declared dividends on common shares in the amount of $64.0 million ($0.50 per common share) during the year ended December 31, 2002, up from $48.5 million ($0.40 per common share) in 2001 (2000 – $ nil).

CAPITAL EXPENDITURES

($ millions)	2002	2001 (1)	2000 (1)
Business combinations	**$ 2,393.2**	$ –	$ 1,687.3
Expenditures on property, plant and equipment			
Net property acquisitions	**$ 440.2**	$ 519.2	$ 150.2
Land acquisition and retention	**113.5**	100.5	79.7
Seismic evaluations	**63.4**	94.6	40.5
Well drilling, completion and equipping	**625.6**	635.3	508.9
Pipeline and production facilities	**292.2**	395.0	335.7
Total net reserve replacement expenditures	**1,534.9**	1,744.6	1,115.0
Horizon Project	**68.1**	26.8	–
Midstream	**20.4**	97.3	–
Abandonments	**42.9**	9.4	15.1
Head office	**9.9**	6.4	5.9
Total net capital expenditures	**$ 1,676.2**	$ 1,884.5	$ 1,136.0
By segment (excluding business combinations)			
North America	**$ 1,132.1**	$ 1,485.5	$ 1,041.8
North Sea	**333.3**	97.8	54.9
Offshore West Africa	**190.4**	203.9	39.3
Midstream	**20.4**	97.3	–
Total	**$ 1,676.2**	$ 1,884.5	$ 1,136.0

(1) Restated to conform to current year presentation.

The Company's strategy is focused on continuing to build a diversified asset base, that is balanced between products, namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil.

Capital expenditures totaled $1,676.2 million in the year 2002, excluding the acquisition of Rio Alto, compared to $1,884.5 million in 2001 (2000 – $1,136.0 million, excluding the acquisition of Ranger). Capital expenditures on North American properties accounted for 69% of total capital expenditures (2001 – 84%, 2000 – 92%), with the remainder expended in the Company's core operating regions in the North Sea and Offshore West Africa. In 2002, the number of net wells drilled (excluding injection/stratigraphic test wells) decreased 39% to 453 from the 739 in 2001 (2000 – 775 net wells). The number of natural gas wells drilled was 162 net wells, down from 476 net wells in 2001 (2000 – 408 net wells), which reflects the Company's decision to defer natural gas drilling from 2002 to 2003 to offset anticipated Ladyfern production declines. In addition, during 2002 the Company drilled 293 net stratigraphic test wells on the oil sands leases in the Horizon Project. The first quarter of 2002 included natural gas exploration that concentrated on larger outlying pools in the Ladyfern area and the construction and commissioning of the Ladyfern natural gas pipeline.

North Sea capital expenditures in 2002 included the consolidation of interests in the Banff, Kyle, Ninian, Lyell, Murchison and Columba fields. The Company also acquired an interest in 12 licenses covering 20 exploration blocks and part blocks, and additional equity interests in the Brent and Ninian pipelines and the Sullom Voe Terminal. The consideration for these acquisitions included cash payments and the Company's interests in the Harding, Pierce and Claymore fields. As a result of these acquisitions, the Company was able to assume operatorship of several fields during 2002.

Offshore West Africa capital expenditures in Côte d'Ivoire included the continued development of the Espoir and Baobab fields. During 2002, three producing wells and two water injection wells were completed in the Espoir field. Unanticipated uphole faults delayed completion of the fourth producing well. Development continued on the Baobab field, where a second successful well was drilled and tested at a rate in excess of 10,000 bbls/d in the first quarter of 2002. The Company received approval for the Baobab development plan by the Government of Côte d'Ivoire in December 2002. During December 2002, a satellite pool, Emien, was drilled but encountered no hydrocarbons. The Company also acquired an interest in the exploration Block CI-400 in deeper waters offshore Côte d'Ivoire. This block is located adjacent to the Baobab discovery. The Company will operate Block CI-400 and retain a 90% working interest. In addition, during 2002 the Company entered into a production sharing agreement ("PSA") for Block 16, offshore Angola, in which the Company has a 50% working interest. The PSA was effective September 1, 2002 for an initial four-year period.

ENVIRONMENT

The Company's environmental management plan and operating guidelines focus on minimizing the impact of field operations while meeting regulatory requirements and corporate standards. The Company as part of this plan has implemented a proactive program than includes:

- An annual internal environmental compliance audit and inspection program of our operating facilities;
- An aggressive suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decomissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A progressive due diligence program related to groundwater monitoring;
- A rigorous program related to preventing and reclaiming spill sites; and
- A solution gas reduction and conservation program.

Internationally, the Company has established stringent operating standards in four areas:

- Using water-based, environmentally friendly drilling muds whenever possible;
- Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;
- Exercising care with respect to all waste produced through effective waste management plans; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2002, the Company's capital expenditures included $42.9 million of abandonment expenditures, up from $9.4 million in 2001 (2000 – $15.1 million).

Estimated future site restoration liability ($ millions, excluding salvage value)	**2002**
North America	**1,206.0**
North Sea	**745.3**
Offshore West Africa	**34.9**
	1,986.2
North Sea PRT recovery	**(304.9)**
	1,681.3

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. It is important to note that the future abandonment costs to be incurred by the Company in the North Sea will result in an estimated recovery of PRT of $304.9 million, as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $1,681.3 million.

The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

RISKS AND UNCERTAINTIES

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing of oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of fluctuating foreign exchange rates; risk of carrying out operations with minimal environmental impact; risk of governmental policies, social instability or other political, economic or diplomatic developments in its international operations; and credit risk of non-payment for sales contracts or non-performance by counterparties to contracts.

The Company uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against potentially significant losses. Operational control is enhanced by focusing efforts on large core regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. In addition, the Company reviews its exposure to individual companies on a regular basis, and where appropriate ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default.

The Company's current position with respect to its financial instruments is detailed in note 12 of the Company's consolidated financial statements. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost, and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

KYOTO PROTOCOL

The Horizon Project is situated on leases containing over 6 billion bbls of mineable oil reserves, supporting a three-phase development that will produce 232,000 bbls/d of light, sweet oil for over 40 years. The Horizon Project encompasses four operational segments: minesite, extraction, primary upgrading and secondary upgrading. Additional development potential also exists on the leases to extract a further 2 billion bbls of mineable reserves and 1 billion bbls of in-situ reserves. To date, capital expenditures of $228.7 million have been incurred on the Horizon Project.

The Company believes that certainty of long-term costs and implementation consistency is required prior to the final commitment for an investment as large as the Horizon Project. In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto") which has resulted in a decrease in cost certainty. Recently, the Canadian Federal Government has provided some limits to the cost of Kyoto implementation through 2012; however, beyond 2012 no implementation certainty exists. As the Horizon Project is scheduled to commence production in 2008 and produce for over 40 years, the lack of clarity on Kyoto implementation over the long term precludes the Company's ability to commit to the construction of the Horizon Project at this time.

The Company anticipates completion of its Design Basis Memorandum ("DBM") phase of engineering in the first quarter of 2003. Although sufficient levels of implementation certainty to start construction do not exist today, the Company anticipates such levels of certainty will be achieved, and therefore has decided to continue with the Engineering Design Specification ("EDS") phase of engineering. The EDS will commence after completion of the DBM, with related 2003 expenditures included in the Company's current Horizon Project budget of $211 million.

The Company will continue to work with the Canadian Federal Government to clarify long-term economic consequences of Kyoto implementation on the Horizon Project before any site clearing or pre-construction work begins in 2004.

CÔTE D'IVOIRE

The Company's development activities in Côte d'Ivoire remain unaffected by recent political insurrection in the country as the Company's operations are located offshore. The Company has established back-up facilities in a neighbouring country to ensure operations are not affected should conditions significantly deteriorate. To date, the Company has not needed to utilize this contingency.

CRITICAL ACCOUNTING ESTIMATES

A comprehensive discussion of the Company's significant accounting policies is contained in note 1 to the consolidated financial statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

FULL COST ACCOUNTING

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants. Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. The capitalized costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Capitalized costs in each cost centre may not exceed the sum of discounted future net revenues from proved properties and the cost of unproved properties, net of provision for impairment, less estimated future financing and administrative expenses and income taxes (the "ceiling test"). If the net capitalized costs of a cost centre are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates, the excess must be charged as an expense against net earnings. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

The alternate acceptable method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method cost centres are defined based on reserve pools rather than by country.

OIL AND NATURAL GAS RESERVES

The Company retains independent petroleum engineering consultants Sproule Associates Limited ("Sproule") to evaluate the Company's proved and probable oil and natural gas reserves and prepares an evaluation report on the Company's total reserves. In 2002, Sproule's report incorporated 89% of the Company's reserves with the Company internally evaluating the remaining 11%.

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depreciation, depletion and amortization. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment under the ceiling test.

FUTURE SITE RESTORATION

The Company provides for the estimated future dismantlement, site restoration and abandonment costs of oil and natural gas properties using the unit-of-production method. Processing and production facilities are provided for using the straight-line method over their estimated useful lives of 20 years. The annual provision is included in depletion, depreciation and amortization. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area specific environmental legislation. These estimates are reviewed regularly and could impact the DD&A rate used by the Company. A revision to these estimated future costs could result in a higher or lower DD&A expense charged to net earnings.

STOCK-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides for granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the day of the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price. Currently, GAAP does not require the Company to record compensation expense in the consolidated financial statements for stock options granted. If the Company had used the fair-value method to account for its stock based compensation, compensation expense of $24.9 million would have been charged to net earnings in 2002. Further details regarding the Company's stock-based compensation are included in note 9 of the consolidated financial statements.

OUTLOOK

The Company continues its strategy of maintaining a large portfolio of varied projects, which enables the Company over an extended period of time to provide consistent growth in production and high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

The Company expects production levels in 2003 to average 1,280 to 1,330 mmcf/d of natural gas and 240 to 260 mbbls/d of oil and liquids, unchanged from previous expectations. First quarter 2003 production guidance for natural gas is 1,300 to 1,320 mmcf/d of natural gas and 235 to 240 mbbls/d of oil and liquids.

The budgeted capital expenditures for 2003 are as follows:

Canadian natural gas properties	$ 691 million
Canadian oil properties	$ 517 million
Horizon Project	$ 211 million
International oil properties – North Sea	$ 281 million
International oil properties – Offshore West Africa	$ 280 million
Property acquisitions	$ 300 million
Total capital expenditures	$ 2,280 million

In North America, the Company will commence development of the undeveloped land acquired in the Rio Alto acquisition with the drilling of 51 wells, 49 of which will be natural gas wells. Approximately 17 of the wells will be Cardium wells, which is a complex geological zone requiring both horizontal and vertical wells to test the production capabilities of the formation. The drilling in 2003 will be utilized to test and develop new geological theories on best practices for exploitation of the Cardium zone, thereby facilitating an expanded 2004 drilling program. In addition, an observation well will be drilled in the experimental Pelican Lake emulsion flood project in the first quarter of 2003 to assess the effectiveness of the injection to date. The Company will also be implementing a demonstration scale waterflood project to evaluate this secondary recovery technique, which should increase response time. If either project is successful, the recovery factor from the Pelican Lake sands is expected to increase. This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 6% recovery factor using primary technologies.

Following regulatory approval in 2002 to utilize high-pressure steaming at its thermal oil project at Primrose in eastern Alberta, the Company will develop and drill new pads containing a total of 48 wells incorporating high-pressure steaming in 2003. Steaming of these wells will commence in the third quarter of 2003 with initial oil production following in mid 2004.

The Company anticipates receiving regulatory approvals for the Horizon Project from the Energy and Utilities Board in late 2003. The Company would be in a position to commence site clearing and pre-construction in 2004, with full construction commencing upon achieving a targeted 80% completion of detailed engineering and design. The first phase of the Horizon Project would then be commissioned in 2008 at 110,000 bbls/d of light synthetic oil. Phase two would be commissioned in 2010, increasing production to 155,000 bbls/d of production. Phase three would be completed in 2012, bringing total production to 232,000 bbls/d. The Company's leases could support further expansions beyond that date.

In 2003, the Company has budgeted to spend a total of $281 million on its international holdings in the North Sea. These funds will be directed towards drilling 18 wells in the North Sea. Other exploitation and waterflood optimization programs will also be carried out in both the northern and central areas of the North Sea to increase the productivity and recovery factors in these known pools of light oil.

Offshore West Africa budgeted capital expenditures total $280 million in 2003. In Côte d'Ivoire, the Company will complete the drilling and completion operations at Espoir, drill an exploration well at Acajou, and finalize the Baobab development plans with development drilling commencing in the fourth quarter of 2003. The Company also plans on drilling one of two identified prospects on its Block 16 exploration acreage, located offshore Angola, during the second half of 2003. This high-risk/high-potential exploration block, in which the Company is the operator with a 50% interest, is located in one of the world's most prolific oil basins.

The original budget was based on an average natural gas price of $5.20 per mcf at AECO, an oil price of US $24.00 per bbl for WTI and a heavy oil differential of US $8.50 per bbl. The current price-deck for our products, if maintained, could result in a significant increase in cash flow over the original budget established late in 2002. The Company will monitor its expected cash flow excess and at present intends to allocate a minimum of 50% of such excess towards debt repayment. The remaining excess will be directed to the Company's authorized share buy-back program and additional expenditures on conventional oil and natural gas opportunities. Such expenditures will only be incurred as excess cash flows are realized and will be subject to the same economic tests as regular budgeted expenditures. It is expected that the largest portion of the additional capital expenditures will take place late in the third and fourth quarters of 2003 and accordingly will not add materially to the Company's 2003 average production volumes. Should additional economic opportunities for share buy-backs or capital activities not present themselves to the extent allocated, such allocations of excess cash flow would revert to debt repayment.

SENSITIVITY ANALYSIS (1)

	Cash flow from operations (2) ($ millions)	Cash flow from operations (2) ($/share, basic)	Net earnings (2) ($ millions)	Net earnings (2) ($/share, basic)
Price changes				
Oil – WTI US $1.00/bbl(3)				
Excluding financial derivatives	**$104**	**$0.78**	**$69**	**$0.52**
Including financial derivatives	**$69–$73**	**$0.51–$0.55**	**$45–$48**	**$0.34–$0.36**
Natural gas – AECO Cdn $0.10/mcf(3)				
Excluding financial derivatives	**$38**	**$0.28**	**$23**	**$0.17**
Including financial derivatives	**$38**	**$0.28**	**$23**	**$0.17**
Volume changes				
Oil – 10,000 bbls/d	**$55**	**$0.41**	**$21**	**$0.15**
Natural gas – 10 mmcf/d	**$12**	**$0.09**	**$4**	**$0.03**
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $(3)				
Excluding financial derivatives	**$57**	**$0.43**	**$15**	**$0.11**
Including financial derivatives	**$52–$55**	**$0.39–$0.41**	**$12–$14**	**$0.09–$0.11**
Interest rate change – 1%	**$24**	**$0.18**	**$15**	**$0.11**

(1) The sensitivities are calculated based on 2002 fourth quarter results.
(2) Attributable to common shareholders.
(3) For details of financial instruments in place, see consolidated financial statements note 12.

DAILY PRODUCTION BY SEGMENT

	Q1	Q2	Q3	Q4	2002	2001	2000
Oil and liquids (bbls/d)							
North America	**152,268**	**158,196**	**185,990**	**181,744**	**169,675**	166,675	154,331
North Sea	**30,910**	**25,685**	**47,114**	**51,478**	**38,876**	36,252	17,195
Offshore West Africa	**5,261**	**5,505**	**8,947**	**7,374**	**6,784**	3,396	2,065
Total	**188,439**	**189,386**	**242,051**	**240,596**	**215,335**	206,323	173,591
Natural gas (mmcf/d)							
North America	**1,026**	**1,058**	**1,395**	**1,331**	**1,204**	906	793
North Sea	**27**	**20**	**29**	**32**	**27**	12	1
Offshore West Africa	**–**	**–**	**3**	**2**	**1**	–	–
Total	**1,053**	**1,078**	**1,427**	**1,365**	**1,232**	918	794
Barrels of oil equivalent (boe/d)							
North America	**323,340**	**334,497**	**418,600**	**403,499**	**370,337**	317,658	286,476
North Sea	**35,389**	**29,020**	**51,946**	**56,879**	**43,391**	38,293	17,446
Offshore West Africa	**5,261**	**5,505**	**9,403**	**7,754**	**6,994**	3,396	2,065
Total	**363,990**	**369,022**	**479,949**	**468,132**	**420,722**	359,347	305,987

PER UNIT RESULTS

	Q1	Q2	Q3	Q4	2002	2001(1)	2000(1)
Oil and liquids ($/bbl)							
Sales price	**$ 24.50**	**$ 28.27**	**$ 33.57**	**$ 31.10**	**$ 29.76**	$ 24.31	$ 29.99
Royalties	**2.28**	**3.02**	**3.56**	**3.53**	**3.16**	2.17	3.05
Production expense	**7.81**	**7.95**	**8.67**	**9.10**	**8.45**	7.64	6.84
Netback	**$ 14.41**	**$ 17.30**	**$ 21.34**	**$ 18.47**	**$ 18.15**	$ 14.50	$ 20.10
Natural gas ($/mcf)							
Sales price	**$ 3.06**	**$ 3.68**	**$ 3.13**	**$ 5.00**	**$ 3.76**	$ 5.16	$ 4.53
Royalties	**0.55**	**0.77**	**0.67**	**1.09**	**0.78**	1.25	1.08
Production expense	**0.58**	**0.57**	**0.55**	**0.57**	**0.57**	0.51	0.44
Netback	**$ 1.93**	**$ 2.34**	**$ 1.91**	**$ 3.34**	**$ 2.41**	$ 3.40	$ 3.01
Barrels of oil equivalent ($/boe)							
Sales price	**$ 21.58**	**$ 25.29**	**$ 26.26**	**$ 30.54**	**$ 26.25**	$ 27.15	$ 28.77
Royalties	**2.78**	**3.79**	**3.80**	**4.98**	**3.91**	4.42	4.51
Production expense	**5.73**	**5.76**	**6.01**	**6.34**	**5.99**	5.69	5.02
Netback	**$ 13.07**	**$ 15.74**	**$ 16.45**	**$ 19.22**	**$ 16.35**	$ 17.04	$ 19.24

(1) Restated to conform to current year presentation.

NETBACK ANALYSIS

($/boe, except daily production)	2002	2001 [1]	2000 [1]
Daily production (boe/d)	**420,722**	359,347	305,987
Sales price	**$ 26.25**	$ 27.15	$ 28.77
Royalties	**3.91**	4.42	4.51
Production expense	**5.99**	5.69	5.02
Netback	**16.35**	17.04	19.24
Midstream contribution	**(0.25)**	(0.12)	(0.26)
Administration	**0.40**	0.29	0.25
Interest	**1.03**	1.05	1.45
Realized foreign exchange loss (gain)	**0.02**	(0.01)	–
Taxes other than income tax (current)	**0.35**	0.53	0.51
Current income tax (North Sea)	**(0.13)**	0.47	0.30
Current income tax (Offshore West Africa)	**0.04**	–	–
Current income tax (Large Corporations Tax)	**0.14**	0.11	0.13
Cash flow	**$ 14.75**	$ 14.72	$ 16.86

(1) Restated to conform to current year presentation.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
2002					
Revenue	**$ 717.5**	**$ 862.8**	**$ 1,172.6**	**$ 1,330.3**	**$ 4,083.2**
Cash flow from operations attributable to common shareholders	**$ 359.1**	**$ 474.5**	**$ 643.8**	**$ 776.6**	**$ 2,254.0**
Per share – basic	**$ 2.95**	**$ 3.86**	**$ 4.83**	**$ 5.81**	**$ 17.63**
– diluted	**$ 2.85**	**$ 3.70**	**$ 4.71**	**$ 5.62**	**$ 16.99**
Net earnings attributable to common shareholders	**$ 98.9**	**$ 145.2**	**$ 117.4**	**$ 208.3**	**$ 569.8**
Per share – basic	**$ 0.81**	**$ 1.18**	**$ 0.88**	**$ 1.56**	**$ 4.46**
– diluted	**$ 0.79**	**$ 1.09**	**$ 0.86**	**$ 1.51**	**$ 4.31**
2001					
Revenue	$ 1,130.7	$ 981.2	$ 810.5	$ 666.4	$ 3,588.8
Cash flow from operations attributable to common shareholders	$ 629.3	$ 527.6	$ 437.4	$ 325.7	$ 1,920.0
Per share – basic	$ 5.15	$ 4.36	$ 3.62	$ 2.69	$ 15.83
– diluted	$ 5.03	$ 4.17	$ 3.54	$ 2.65	$ 15.23
Net earnings attributable to common shareholders	$ 221.8	$ 286.6	$ 81.3	$ 52.9	$ 642.6
Per share – basic	$ 1.82	$ 2.37	$ 0.67	$ 0.44	$ 5.30
– diluted	$ 1.77	$ 2.23	$ 0.66	$ 0.43	$ 5.17

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2002 Total	2001 Total
TSX – CDN $						
Trading volume (thousands)	**35,401**	**40,769**	**34,404**	**44,255**	**154,829**	133,744
Share price ($/share)						
High	**$ 53.05**	**$ 54.54**	**$ 53.91**	**$ 50.50**	**$ 54.54**	$ 52.35
Low	**$ 37.60**	**$ 46.60**	**$ 44.10**	**$ 38.80**	**$ 37.60**	$ 35.90
Close	**$ 51.60**	**$ 51.52**	**$ 50.35**	**$ 46.80**	**$ 46.80**	$ 38.31
Market capitalization at December 31 ($ millions)					**$ 6,261**	$ 4,643
Shares outstanding (thousands)					**133,776**	121,201
NYSE – US $						
Trading volume (thousands)	**1,400**	**1,923**	**1,365**	**3,278**	**7,966**	5,191
Share price ($/share)						
High	**$ 33.25**	**$ 34.48**	**$ 34.88**	**$ 31.81**	**$ 34.88**	$ 34.51
Low	**$ 23.55**	**$ 29.52**	**$ 27.52**	**$ 24.55**	**$ 23.55**	$ 22.80
Close	**$ 32.94**	**$ 34.25**	**$ 31.80**	**$ 29.67**	**$ 29.67**	$ 24.40
Market capitalization at December 31 ($ millions)					**$ 3,969**	$ 2,957
Shares outstanding (thousands)					**133,776**	121,201

management's report and auditors' report

management's report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board of Directors for approval. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

John G. Langille, CA
President and Director

Douglas A. Proll, CA
Senior Vice-President, Finance

Randall S. Davis, CA
Financial Controller
February 26, 2003

auditors' report

To the Shareholders of Canadian Natural Resources Limited

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2002 and 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 consolidated 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 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 26, 2003

Comments by Auditor for US readers on Canada-US 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 26, 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 26, 2003

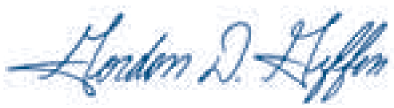
consolidated financial statements

consolidated balance sheets

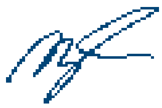
As at December 31 (millions of Canadian dollars)	2002	2001
ASSETS		
Current assets		
Cash	$ 30.0	$ 15.0
Accounts receivable and other	745.2	509.0
	775.2	524.0
Property, plant and equipment (note 4)	12,499.6	8,442.9
Deferred charges	84.1	–
	13,358.9	8,966.9
LIABILITIES		
Current liabilities		
Accounts payable	336.5	249.5
Accrued liabilities	428.4	264.2
Current portion of long-term debt (note 5)	24.1	15.9
	789.0	529.6
Long-term debt (note 5)	4,074.0	2,669.2
Future site restoration (note 6)	440.4	193.8
Future income tax (note 7)	3,187.4	1,767.3
	8,490.8	5,159.9
SHAREHOLDERS' EQUITY		
Preferred securities (note 8)	126.4	127.4
Share capital (note 9)	2,303.8	1,698.3
Retained earnings	2,414.3	1,908.5
Foreign currency translation adjustment (note 10)	23.6	72.8
	4,868.1	3,807.0
	$ 13,358.9	$ 8,966.9

Commitments (note 13)

Signed on behalf of the Board:



Ambassador Gordon D. Giffin
Chairman of the Audit Committee and Director



N. Murray Edwards
Vice-Chairman of the Corporation and Director

consolidated financial statements

consolidated statements of earnings

For the Years Ended December 31 (millions of Canadian dollars, except per common share amounts)	2002	2001	2000
Revenue	**$ 4,083.2**	$ 3,588.8	$ 3,260.6
Less: royalties	**(600.3)**	(580.3)	(506.2)
	3,482.9	3,008.5	2,754.4
Expenses			
Production	**933.9**	757.9	571.0
Depletion, depreciation and amortization	**1,314.2**	903.8	644.6
Administration	**61.3**	37.6	27.2
Interest	**158.9**	137.8	162.3
Foreign exchange (gain) loss (note 2)	**(31.7)**	62.8	15.9
Loss on sale of United States assets (note 4)	**–**	24.1	–
	2,436.6	1,924.0	1,421.0
Earnings before taxes	**1,046.3**	1,084.5	1,333.4
Taxes other than income tax (note 7)	**62.9**	69.1	49.5
Current income tax (note 7)	**7.6**	76.9	48.4
Future income tax (note 7)	**401.0**	282.5	464.0
Net earnings	**574.8**	656.0	771.5
Dividend on preferred securities, net of tax	**(6.0)**	(5.9)	(2.8)
Revaluation of preferred securities (note 2)	**1.0**	(7.5)	(1.6)
Net earnings attributable to common shareholders	**$ 569.8**	$ 642.6	$ 767.1
Net earnings attributable to common shareholders per common share (note 11)			
Basic	**$ 4.46**	$ 5.30	$ 6.57
Diluted	**$ 4.31**	$ 5.17	$ 6.39

consolidated statements of retained earnings

For the Years Ended December 31 (millions of Canadian dollars)	2002	2001	2000
Balance – beginning of year as previously reported	**$ 1,979.5**	$ 1,406.0	$ 623.8
Change in accounting policy – foreign exchange (note 2)	**(71.0)**	(15.4)	(0.3)
Balance – beginning of year as restated	**1,908.5**	1,390.6	623.5
Net earnings	**574.8**	656.0	771.5
Dividend on preferred securities, net of tax	**(6.0)**	(5.9)	(2.8)
Revaluation of preferred securities (note 2)	**1.0**	(7.5)	(1.6)
Dividend on common shares (note 9)	**(64.0)**	(48.5)	–
Purchase of common shares (note 9)	**–**	(76.2)	–
Balance – end of year	**$ 2,414.3**	$ 1,908.5	$ 1,390.6

consolidated statements of cash flows

For the Years Ended December 31 (millions of Canadian dollars)	2002	2001	2000
Operating activities			
Net earnings	**$ 574.8**	$ 656.0	$ 771.5
Non-cash items			
Depletion, depreciation and amortization	**1,314.2**	903.8	644.6
Unrealized foreign exchange (gain) loss	**(35.1)**	64.1	16.1
Deferred petroleum revenue tax	**9.5**	(0.2)	(7.6)
Future income tax	**401.0**	282.5	464.0
Loss on sale of United States assets	**–**	24.1	–
Cash flow provided from operations	**2,264.4**	1,930.3	1,888.6
Deferred charges	**(84.1)**	–	–
Net change in non-cash working capital	**(156.9)**	(42.2)	(55.4)
	2,023.4	1,888.1	1,833.2
Financing activities			
Repayment of bank credit facilities	**(1,234.3)**	(442.3)	(187.7)
Issue of medium-term notes	**–**	–	125.0
Repayment of senior unsecured notes	**(15.9)**	(15.8)	(15.1)
Issue of US dollar debt securities	**1,749.3**	615.2	–
Repayment of obligations under capital leases	**(3.9)**	–	–
Repayment of limited recourse loan	**–**	(11.8)	(0.7)
Dividend on preferred securities	**(10.4)**	(10.3)	(5.0)
Issue of common shares	**84.1**	42.8	66.4
Dividend on common shares	**(59.4)**	(36.4)	–
Purchase of common shares	**–**	(113.3)	–
Net change in non-cash working capital	**26.0**	7.4	5.8
	535.5	35.5	(11.3)
Investing activities			
Business combinations, net of cash acquired (note 3)	**(843.2)**	–	(722.8)
Expenditures on property, plant and equipment	**(1,752.3)**	(1,947.5)	(1,294.6)
Net proceeds on sale of property, plant and equipment	**76.1**	63.0	160.3
Net expenditures on property, plant and equipment	**(2,519.4)**	(1,884.5)	(1,857.1)
Net change in non-cash working capital	**(24.5)**	(52.1)	63.1
	(2,543.9)	(1,936.6)	(1,794.0)
Increase (decrease) in cash	**15.0**	(13.0)	27.9
Cash – beginning of year	**15.0**	28.0	0.1
Cash – end of year	**$ 30.0**	$ 15.0	$ 28.0

Supplemental disclosure of cash flow information (note 14)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in North America, largely in western Canada, the North Sea and Offshore West Africa.

Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada. A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US") is contained in note 16.

Significant accounting policies are summarized as follows:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. Portions of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. 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.

Depletion, depreciation and amortization and amounts used for ceiling test calculations are based on estimates of proved oil and natural gas reserves and future sales prices, production expenses and capital costs required to develop and produce those reserves. The majority of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

CASH

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with a term to maturity of three months or less from the transaction date are reported as cash equivalents.

PROPERTY, PLANT AND EQUIPMENT

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Administrative overhead incurred during the development phase of large capital projects is capitalized until commercial production commences. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

DEPLETION, DEPRECIATION AND AMORTIZATION

The costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties. The unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs in cost centres from which there has been no commercial production are not subject to depletion until commercial production commences.

Processing and production facilities, net of salvage value, are depreciated on a straight-line basis over their estimated useful lives of 20 years.

The Company carries its oil and natural gas properties at the lower of net capitalized cost and net recoverable amount (the "ceiling test"). The net capitalized cost of each cost centre is calculated as the net book value of the related assets less the accumulated provisions for future income taxes and future site restoration. Net recoverable amount is limited to the sum of undiscounted future net revenues from proved properties and the cost of unproved properties net of provisions for impairment less estimated future financing and administrative expenses and income taxes. Future net revenues are based on sales prices and costs prevailing at year end.

The Company carries its midstream assets at the lower of net capitalized cost and net recoverable amount. Midstream assets, net of salvage value, are depreciated on a straight-line basis over their estimated useful lives of 20 years.

Other capital assets are amortized on a declining balance basis over their estimated useful lives of five years.

DEFERRED CHARGES

Deferred charges include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

FUTURE SITE RESTORATION

Estimated future dismantlement, site restoration and abandonment costs of oil and natural gas properties are provided for using the unit-of-production method. Processing and production facilities are provided for using the straight-line method over their estimated useful lives of 20 years. The estimated costs are based on engineering estimates using current costs and technology in accordance with current legislation and industry practice. The annual provision is included in depletion, depreciation and amortization. Expenditures incurred to dismantle the processing and production facilities and to abandon and restore well sites are charged against the related site restoration liability.

FOREIGN CURRENCY TRANSLATION

Foreign operations that are operationally and financially independent are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

Foreign operations that are not considered to be self-sustaining are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date and non-monetary assets and liabilities are translated at the rate of exchange in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related items.

PETROLEUM REVENUE TAX

The Company accounts for future United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

PRODUCTION SHARING CONTRACT

Production generated from the Espoir field, offshore Côte d'Ivoire, is shared by the terms of the Production Sharing Contract ("PSC") with the State Oil Company of Côte d'Ivoire ("Petroci"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover the capital and operating costs carried by the Company on behalf of Petroci. These revenues are reported as sales revenues. Profit revenues are allocated to the Espoir joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Côte d'Ivoire Government. The Government's share of revenues, attributable to the Company's equity interest, is reported as either a royalty expense or a current tax expense in accordance with the PSC.

INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

REVENUE RECOGNITION

Revenues are recognized when products have been delivered or services have been performed.

STOCK-BASED COMPENSATION PLANS

The Company accounts for its stock-based compensation using the intrinsic value method; therefore, no stock-based compensation expense is recorded either on granting or exercise of stock options under the Company's Stock Option Plan (the "Option Plan"). Consideration paid by employees, officers or directors on the exercise of stock options under the Option Plan is recorded as share capital. The Company matches employee contributions to the Company's Stock Savings Plan and these cash payments are recorded as compensation expense.

FINANCIAL INSTRUMENTS

Financial instruments are utilized by the Company to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

The Company's policy is to formally document relationships between hedging instruments and hedged items, the risk management objective, and the strategy for undertaking various hedge transactions. The Company assesses whether the financial instruments entered into are highly effective as fair value and cash flow hedges, both at the inception of the hedge and over the term of the financial instrument.

The Company enters into commodity price contracts to hedge anticipated sales of oil and natural gas production in order to protect cash flow for capital expenditure programs. Gains or losses on these contracts are included in oil and natural gas revenue at the time of sale of the related product.

Foreign exchange translation gains and losses on foreign currency denominated financial instruments used to hedge anticipated US dollar denominated oil and natural gas sales are recognized in revenue at the time of sale of the related product.

The Company has assumed, through the Rio Alto acquisition, a foreign currency swap agreement that hedges a foreign currency denominated long-term debt instrument through an offsetting forward exchange contract. The foreign exchange translation gains and losses on the financial instrument are used to offset the respective translation gains and losses recognized on the long-term debt.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. These swaps are designated as hedges of the underlying debt. The interest rate swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on these financial instruments are included in interest expense in the consolidated statement of earnings when realized. The related amount receivable from or payable to counterparties is included as an adjustment to accrued interest in the consolidated balance sheets.

Realized gains and losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and recognized in net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in net earnings.

PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price during the year.

COMPARATIVE FIGURES

Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2002.

2. CHANGE IN ACCOUNTING POLICY

FOREIGN CURRENCY TRANSLATION

Effective January 1, 2002, the Company retroactively adopted the CICA's new accounting standard with respect to foreign currency translation. As a result of adopting this new standard, gains or losses on the translation of long-term debt denominated in US dollars are no longer deferred and amortized over the term of the debt. Translation gains or losses are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 10) for translation gains or losses on that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations. This new standard has been adopted retroactively and prior periods have been restated.

The new standard affects the Company's accounting for US dollar denominated long-term debt and preferred securities. Adoption of the new accounting policy had the following effects on the Company's consolidated financial statements:

	2002	2001	2000
Consolidated balance sheets			
Decrease deferred foreign exchange loss	**$ –**	$ (61.9)	$ (13.8)
(Decrease) increase preferred securities	**$ (1.0)**	$ 9.1	$ 1.6
Decrease in opening retained earnings	**$ (71.0)**	$ (15.4)	$ (0.3)
Consolidated statements of earnings			
Foreign exchange (gain) loss	**$ (53.3)**	$ 48.1	$ 13.5
Revaluation of preferred securities (gain) loss	**$ (1.0)**	$ 7.5	$ 1.6
Increase (decrease) net earnings attributable to			
common shareholders per common share			
– Basic	**$ 0.42**	$ (0.46)	$ (0.13)
– Diluted	**$ 0.40**	$ (0.38)	$ (0.11)

3. BUSINESS COMBINATIONS

RIO ALTO EXPLORATION LTD.

In July 2002, the Company paid cash of $850.0 million and issued 10,008,218 common shares with an attributed value of $522.4 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement (the "Plan of Arrangement").

Rio Alto was engaged in the exploration for and production of oil and natural gas in western Canada and through wholly owned subsidiaries, in South America. Under the Plan of Arrangement, the subsidiaries of Rio Alto that held its South American properties were sold to a new company, Rio Alto Resources International Inc. ("Rio Alto International"), and each shareholder of Rio Alto received one common share of Rio Alto International for each Rio Alto common share held.

The acquisition was accounted for based on the purchase method. Results of Rio Alto are consolidated with the results of the Company since the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

	July 1, 2002
Purchase price:	
Cash consideration	**$ 850.0**
Share consideration	**522.4**
Cash acquired	**(6.8)**
Non-cash working capital deficit assumed	**91.3**
Long-term debt assumed	**936.3**
Total purchase price	**$ 2,393.2**
Purchase price allocated as follows:	
Property, plant and equipment	**$ 3,411.8**
Future site restoration	**(43.5)**
Future income tax	**(975.1)**
	$ 2,393.2

RANGER OIL LIMITED

In July 2000, the Company paid cash of $722.8 million and issued 7,602,068 common shares with an attributed value of $358.0 million to acquire all of the issued and outstanding common shares of Ranger Oil Limited ("Ranger"). Ranger was engaged in the exploration for and development of oil and natural gas in the North Sea, North America and Offshore West Africa.

The acquisition was accounted for based on the purchase method. Results of Ranger are consolidated with the results of the Company since the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

	July 1, 2000
Purchase price:	
Cash consideration	$ 722.8
Share consideration	358.0
Non-cash working capital deficit assumed	111.6
Long-term debt assumed	376.6
Preferred securities assumed	118.3
Total purchase price	$ 1,687.3
Purchase price allocated as follows:	
Property, plant and equipment	$ 1,966.4
Future site restoration	(129.3)
Future income tax	(149.8)
	$ 1,687.3

4. PROPERTY, PLANT AND EQUIPMENT

	2002		
	Cost	**Accumulated depletion and depreciation**	**Net**
Oil and natural gas			
North America	**$ 13,863.3**	**$ 3,611.3**	**$ 10,252.0**
North Sea	**1,621.2**	**344.2**	**1,277.0**
Offshore West Africa	**611.9**	**93.6**	**518.3**
Horizon Project	**228.7**	**–**	**228.7**
Midstream	**214.0**	**18.4**	**195.6**
Other	**50.1**	**22.1**	**28.0**
	$ 16,589.2	**$ 4,089.6**	**$ 12,499.6**

4. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

	2001		
	Cost	Accumulated depletion and depreciation	Net
Oil and natural gas			
North America	$ 9,424.7	$ 2,617.1	$ 6,807.6
North Sea	1,050.3	184.7	865.6
Offshore West Africa	425.2	15.3	409.9
Horizon Project	160.6	–	160.6
Midstream	193.6	10.8	182.8
Other	32.3	15.9	16.4
	$ 11,286.7	$ 2,843.8	$ 8,442.9

During the year ended December 31, 2002, the Company capitalized administrative overhead of $13.0 million (2001 – $6.7 million; 2000 – $3.7 million) relating to exploration and development in the North Sea and Offshore West Africa and $3.9 million (2001 – $nil, 2000 – $nil) relating to the Horizon Project in North America. During 2001, the Company sold a large portion of its properties in the United States and recorded a loss on sale of $24.1 million.

Included in property, plant and equipment are undeveloped land and projects under development that are not subject to depletion or depreciation:

	2002	2001	2000
Oil and natural gas			
North America	**$ 666.8**	$ 424.0	$ 351.5
North Sea	**62.0**	49.5	45.5
Offshore West Africa	**131.8**	398.8	175.3
Horizon Project	**228.7**	160.6	141.8
	$ 1,089.3	$ 1,032.9	$ 714.1

5. LONG-TERM DEBT

	2002	2001
Bank credit facilities		
Bankers' acceptances	**$ 728.0**	$ 1,003.4
US $ Bankers' acceptances (2002 – US $150.0 million, 2001 – US $196.0 million)	**236.9**	312.1
US $ LIBOR advances (2002 – US $nil, 2001 – US $100.0 million)	**–**	159.3
Medium-term notes		
6.85% unsecured debentures due May 28, 2004	**125.0**	125.0
7.40% unsecured debentures due March 1, 2007	**125.0**	125.0
Senior unsecured notes		
6.95% due September 30, 2003 (2002 – US $10.0 million, 2001 – US $20.0 million)	**15.8**	31.9
6.42% due May 27, 2004 (US $40.0 million)	**63.2**	63.7
7.69% due December 19, 2005 (US $125.0 million)	**193.7**	–
6.50% due May 1, 2008 (US $50.0 million)	**79.0**	79.6
Adjustable rate due May 27, 2009 (US $93.0 million)	**146.9**	148.1
US dollar debt securities		
6.70% due July 15, 2011 (US $400.0 million)	**631.8**	637.0
5.45% due October 1, 2012 (US $350.0 million)	**552.9**	–
7.20% due January 15, 2032 (US $400.0 million)	**631.8**	–
6.45% due June 30, 2033 (US $350.0 million)	**552.9**	–
Obligations under capital leases	**15.2**	–
	4,098.1	2,685.1
Less: current portion of long-term debt	**24.1**	15.9
	$ 4,074.0	$ 2,669.2

BANK CREDIT FACILITIES

The Company has unsecured bank credit facilities of $2,275.0 million comprised of a $100.0 million operating demand facility, a revolving credit and term loan facility of $1,675.0 million and a $500.0 million acquisition term credit facility repayable July 3, 2004. The Canadian dollar revolving credit and term loan facility is fully revolving for 364-day periods with a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving reducing loan with a term of three years. Principal payments during the term period amortize on the basis of one-third of the outstanding principal being due 12 months after the initiation of the term period followed by eight equal quarterly payments thereafter. The facility provides that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances which bear interest at the bank's prime rates or at money market rates plus applicable margins. During the year, the Company repaid and cancelled a $725.0 million credit and term loan facility and a US $150.0 million credit and term loan facility.

The weighted average interest rate of bank credit facilities outstanding at December 31, 2002 was 3.37% (2001 – 2.71%). Included in this rate is debt under the bank credit facilities totaling $100.0 million that is subject to an interest rate swap that fixes the interest rate at 5.08% plus a stamping fee (note 12).

In addition to the outstanding debt, letters of credit aggregating to $25.1 million have been issued.

MEDIUM-TERM NOTES

In July 2001, the Company authorized a medium-term note program in the aggregate principal amount of up to $1.0 billion for issue in Canada until July 2003. If issued, these notes will bear interest as determined at the date of issuance. No amounts are currently drawn under this program. The Company has $250.0 million of unsecured debentures outstanding from a previous medium-term note program.

SENIOR UNSECURED NOTES

The final principal repayment on the 6.95% senior unsecured notes is due September 30, 2003. The 6.42% senior unsecured notes are due in full May 27, 2004. Annual principal repayments of US $10.0 million on the 6.50% notes commence May 1, 2004, and are payable through May 1, 2008. The adjustable rate senior unsecured notes bear interest at 6.54% increasing to 6.64% under certain circumstances, and have annual principal repayments of US $31.0 million commencing on May 27, 2007, through May 27, 2009. The debt instruments contain covenants pertaining to the Company's net worth, certain financial ratios and the ability to grant security.

On July 1, 2002, as part of the Rio Alto acquisition, the Company assumed US $125.0 million of senior unsecured notes maturing December 19, 2005, bearing interest at 7.69%. Through a currency swap, the interest and principal repayment amounts are fixed at 7.30% and $193.7 million, respectively (note 12).

US DOLLAR DEBT SECURITIES

On July 24, 2001, the Company issued US $400.0 million of US dollar debt securities, maturing July 15, 2011, bearing interest at 6.70%. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 12).

On January 23, 2002, the Company issued US $400.0 million of US dollar debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 12).

On September 16, 2002, the Company issued US $350.0 million of US dollar debt securities maturing October 1, 2012, bearing interest at 5.45% and US $350.0 million of US dollar debt securities maturing June 30, 2033, bearing interest at 6.45%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the ten-year securities (note 12).

The Company has US $300.0 million remaining on a US $1.0 billion shelf prospectus filed on August 16, 2002 that allows for the issue of debt securities until September 2004. If issued, these securities will bear interest as determined at the date of issuance.

OBLIGATIONS UNDER CAPITAL LEASES

The obligations under capital leases bear interest at an average interest rate of 6.91% and are secured by the related assets.

REQUIRED DEBT REPAYMENTS

Required debt repayments are as follows:

Year	Repayment
2003	$ 24.1
2004	$ 710.8
2005	$ 209.5
2006	$ 15.8
2007	$ 189.8
Thereafter	$ 2,483.2

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities, other than the $500.0 million acquisition term credit facility due July 3, 2004.

6. FUTURE SITE RESTORATION

	2002	2001
Balance – beginning of year	$ 193.8	$ 170.5
Future site restoration provision	69.4	34.1
Current year expenditures	(34.3)	(9.4)
Acquisitions and dispositions	211.5	(1.4)
Balance – end of year	$ 440.4	$ 193.8

At December 31, 2002, the Company's total estimated future site restoration costs, excluding salvage values, were $1,986.2 million (2001 – $1,081.0 million, 2000 – $874.3 million). These costs are accrued over the life of the Company's proved reserves.

7. TAXES

Taxes other than income tax	2002	2001	2000
Current petroleum revenue tax	$ 41.6	$ 59.3	$ 40.9
Deferred petroleum revenue tax	9.5	(0.2)	(7.6)
Provincial capital taxes and surcharges	11.1	8.5	12.3
Other	0.7	1.5	3.9
	$ 62.9	$ 69.1	$ 49.5

Income tax

The provision for income tax is as follows:

	2002	2001	2000
Current income tax expense			
Current income tax – North Sea	$ (19.6)	$ 61.8	$ 33.7
Current income tax – Offshore West Africa	6.0	–	–
Large Corporations Tax – North America	21.2	15.1	14.7
	7.6	76.9	48.4
Future income tax expense	401.0	282.5	464.0
Income taxes	$ 408.6	$ 359.4	$ 512.4

The provision for income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2002	2001	2000
Canadian statutory income tax rate	42.4%	42.8%	44.0%
Income tax provision at statutory rate	$ 443.6	$ 464.2	$ 586.7
Effect on income taxes of:			
Non-deductible crown royalties, lease rentals and mineral taxes	211.0	201.1	193.2
Resource allowance	(243.4)	(219.5)	(238.1)
Large Corporations Tax	21.2	15.1	14.7
Deductible petroleum revenue tax	(21.7)	(25.3)	(14.6)
Foreign income tax rate differentials	(1.4)	(18.9)	(40.9)
Provincial income tax rate reductions	(20.5)	(63.1)	–
UK income tax rate increase	34.0	–	–
Foreign exchange	(21.7)	20.6	5.9
Other	7.5	(14.8)	5.5
Income taxes	$ 408.6	$ 359.4	$ 512.4

The following table summarizes the temporary differences that give rise to the future income tax liability:

	2002	2001
Future income tax liabilities		
Property, plant and equipment	**$ 2,656.0**	$ 1,384.8
Timing of partnership items	**736.9**	493.2
Other	**27.5**	5.0
Future income tax assets		
Future site restoration	**(160.5)**	(54.1)
Attributed Canadian Royalty Income	**(54.0)**	(39.8)
Other	**(14.1)**	(9.9)
Deferred petroleum revenue tax	**(4.4)**	(11.9)
Future income tax liability	**$ 3,187.4**	$ 1,767.3

8. PREFERRED SECURITIES

The US $80.0 million preferred securities are in the form of 8.30% subordinated notes. Principal repayments of US $26.7 million are required annually commencing June 25, 2009. The securities may be prepaid at the option of the Company at any time. The prepaid amount is subject to certain adjustments to compensate holders for any potential loss of return over the original life of the securities, based on market conditions at that time. The notes are subordinated to the long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios.

The Company has the unrestricted right to pay dividends, principal and principal prepayment amounts by delivering common shares to the Trustee of the preferred securities. Accordingly, the preferred securities are classified as shareholders' equity in the consolidated balance sheets. Dividend payments, net of tax, are charged directly to retained earnings. The semi-annual dividend payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

9. SHARE CAPITAL

AUTHORIZED

200,000 Class 1 preferred shares with a stated value of $10.00 each.
Unlimited number of common shares without par value.

ISSUED

	2002		2001	
Common shares	**Number of shares** (thousands)	**Amount**	Number of shares (thousands)	Amount
Balance – beginning of year	**121,201**	**$ 1,698.3**	122,279	$ 1,688.0
Issued upon acquisition of Rio Alto	**10,008**	**522.4**	–	–
Issued upon exercise of stock options	**2,523**	**82.1**	1,005	29.2
Issue of flow-through shares, net of tax	**60**	**1.3**	–	–
Cancellation of common shares	**(16)**	**(0.3)**	–	–
Exercise of warrants	**–**	**–**	455	16.3
Purchase of common shares under Normal Course Issuer Bid	**–**	**–**	(2,538)	(35.2)
Balance – end of year	**133,776**	**$ 2,303.8**	121,201	$ 1,698.3

The Company issued 10,008,218 common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto (note 3).

In January 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2.3 million. The value of the common shares was determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the allotment.

During the year, 16,288 common shares were returned to treasury and cancelled on the expiry of the conversion period for exchanging shares of companies previously acquired for common shares of the Company.

NORMAL COURSE ISSUER BID

In January 2003, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,692,799 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2003 and ending January 23, 2004. As at February 26, 2003, 175,600 common shares for a total cost of $8.3 million have been purchased under this renewed Normal Course Issuer Bid.

Under a previous Normal Course Issuer Bid, the Company purchased 2,537,800 common shares in 2001 for a total cost of $113.3 million. The excess cost over book value of the common shares purchased was applied to eliminate contributed surplus and reduce retained earnings.

DIVIDEND POLICY

The Company pays regular quarterly dividends in January, April, July and October of each year. In February 2003, the Board of Directors set the Company's regular quarterly dividend at $0.15 per common share (2002 – $0.125 per common share, 2001 – $0.10 per common share, 2000 – $nil per common share) commencing with the April 1, 2003 payment.

WARRANTS

During 1999, the Company issued 500,000 warrants at an ascribed value of $2.9 million to acquire property, plant and equipment. Each warrant entitled the holder to acquire one common share of the Company at a price of $30.00 per common share until August 16, 2001.

STOCK OPTIONS

The Company's Stock Option Plan (the "Option Plan") provides for the granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the day of the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes information relating to stock options outstanding and exercisable under the Option Plan at December 31, 2002 and 2001:

	2002		2001	
	Stock options (thousands)	**Weighted average exercise price**	Stock options (thousands)	Weighed average exercise price
Outstanding – beginning of year	**12,051**	**$ 34.77**	10,664	$ 32.78
Granted	**3,845**	**$ 41.88**	3,500	$ 40.85
Exercised	**(2,523)**	**$ 32.54**	(1,005)	$ 29.12
Forfeited	**(491)**	**$ 40.03**	(1,108)	$ 39.89
Outstanding – end of year	**12,882**	**$ 37.13**	12,051	$ 34.77
Exercisable – end of year	**3,508**	**$ 32.53**	3,615	$ 31.42

The range of exercise prices of stock options outstanding and exercisable under the Option Plan at December 31, 2002 is as follows:

	Stock Options Outstanding			**Stock Options Exercisable**	
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)	**Weighted average exercise price**	**Stock options exercisable** (thousands)	**Weighed average exercise price**
$19.90 to $24.99	1,106	1.8	$ 22.02	750	$ 22.01
$25.00 to $29.99	1,069	1.2	$ 27.13	691	$ 27.19
$30.00 to $34.99	2,555	2.8	$ 33.63	927	$ 33.61
$35.00 to $39.99	4,556	4.4	$ 39.03	578	$ 39.20
$40.00 to $44.99	1,868	4.3	$ 43.19	446	$ 43.97
$45.00 to $48.50	1,728	5.2	$ 46.61	116	$ 46.59
	12,882	3.7	$ 37.13	3,508	$ 32.53

STOCK-BASED COMPENSATION COSTS

The Company accounts for its stock-based compensation using the intrinsic value method and as a result, no compensation costs have been recorded in the consolidated financial statements for stock options granted or exercised. Had the Company adopted the fair value based method of accounting, the compensation costs, along with the pro forma net earnings attributable to common shareholders and pro forma net earnings attributable to common shareholders per common share of the Company would be as follows:

	2002	2001	2000
Stock-based compensation costs	**$ 24.9**	$ 18.8	$ 8.5
Net earnings attributable to common shareholders			
As reported	**$ 569.8**	$ 642.6	$ 767.1
Pro forma	**$ 544.9**	$ 623.8	$ 758.6
Net earnings attributable to common shareholders per common share			
Basic			
As reported	**$ 4.46**	$ 5.30	$ 6.57
Pro forma	**$ 4.26**	$ 5.14	$ 6.50
Diluted			
As reported	**$ 4.31**	$ 5.17	$ 6.39
Pro forma	**$ 4.12**	$ 5.03	$ 6.32

The stock-based compensation costs are recognized over the vesting period of the stock options granted. The pro forma amounts shown above do not include the stock-based compensation costs associated with stock options granted prior to January 1, 2000.

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option pricing model based on the following:

	2002	2001	2000
Fair value of stock options granted (per common share)			
Directors, officers and executives	**$ 14.70**	$ 16.52	$ 16.35
Other employees	**$ 12.29**	$ 13.56	$ 14.00
Risk-free interest rate	**3.7%**	5.2%	6.2%
Expected life (years)			
Directors, officers and executives	**5.5**	5.5	5.5
Other employees	**3.7**	3.6	3.6
Expected volatility	**35%**	39%	38%
Expected dividend yield	**1.2%**	1.0%	–

10. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, gains and losses on this debt are included in the foreign currency translation adjustment.

	2002	2001
Balance – beginning of year	**$ 72.8**	$ –
Unrealized (loss) gain on translation of net investment	**(11.6)**	72.8
Hedge of net investment with US dollar denominated debt	**(37.6)**	–
Balance – end of year	**$ 23.6**	$ 72.8

11. NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

The following table provides a reconciliation between basic and diluted amounts per common share:

(thousands)	**2002**	2001	2000
Weighted average common shares outstanding – basic	**127,883**	121,300	116,701
Effect of dilutive stock options and warrants	**2,744**	2,594	2,624
Assumed settlement of preferred securities with common shares	**2,681**	2,883	1,427
Weighted average common shares outstanding – diluted	**133,308**	126,777	120,752
Net earnings attributable to common shareholders	**$ 569.8**	$ 642.6	$ 767.1
Dividend on preferred securities, net of tax	**6.0**	5.9	2.8
Revaluation of preferred securities	**(1.0)**	7.5	1.6
Diluted net earnings attributable to common shareholders	**$ 574.8**	$ 656.0	$ 771.5
Net earnings attributable to common shareholders per common share			
Basic	**$ 4.46**	$ 5.30	$ 6.57
Diluted	**$ 4.31**	$ 5.17	$ 6.39
Cash flow from operations attributable to common shareholders	**$ 2,254.0**	$ 1,920.0	$ 1,883.6
Dividend on preferred securities	**10.4**	10.3	5.0
Diluted cash flow from operations attributable to common shareholders	**$ 2,264.4**	$ 1,930.3	$ 1,888.6
Cash flow from operations attributable to common shareholders per common share			
Basic	**$ 17.63**	$ 15.83	$ 16.14
Diluted	**$ 16.99**	$ 15.23	$ 15.64

For the year ended December 31, 2002, 319,916 stock options with a weighted average exercise price of $48.33 (2001 – 692,790 stock options with a weighted average exercise price of $45.78, 2000 – 1,861,475 stock options with a weighted average exercise price of $44.38) were excluded from the calculation of per common share amounts as their effect on per common share amounts was anti-dilutive.

12. FINANCIAL INSTRUMENTS

FINANCIAL CONTRACTS

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments are as follows:

	2002		2001	
	Carrying value	**Fair value**	Carrying value	Fair value
Asset (liability)				
Derivative financial instruments	**$ –**	**$ 56.4**	$ –	$ (32.9)
Fixed rate notes	**$ (3,259.6)**	**$ (3,573.2)**	$ (1,328.6)	$ (1,336.9)

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes.

The following summarizes transactions outstanding as at February 26, 2003, which includes all transactions outstanding at December 31, 2002:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps	Jan. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/ WTI
Oil price collars	Jan. 2003 – Mar. 2003	117,333 bbls/d	US $22.74 – US $28.26	WTI
	Apr. 2003 – Jun. 2003	110,667 bbls/d	US $22.48 – US $28.06	WTI
	Jul. 2003 – Sep. 2003	73,333 bbls/d	US $23.45 – US $28.75	WTI
	Oct. 2003 – Dec. 2003	40,000 bbls/d	US $24.00 – US $30.17	WTI
Natural gas				
NYMEX collar	Jan. 2003 – Oct. 2003	30,000 mmbtu/d	US $2.88 – US $6.12	NYMEX
Sumas fixed	Jan. 2003 – Oct. 2003	10,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars	Jan. 2003 – Mar. 2003	500,000 GJ/d	Cdn $4.16 – Cdn $6.98	AECO
	Apr. 2003 – Jun. 2003	240,000 GJ/d	Cdn $4.13 – Cdn $6.11	AECO
	Jul. 2003 – Sep. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO
	Oct. 2003	40,000 GJ/d	Cdn $3.50 – Cdn $5.38	AECO

	Remaining Term	Amount ($ millions)	Average Exchange Rate (US $/Cdn $)
Foreign currency			
Currency collars	Jan. 2003 – May 2003	US $4.2/month	1.43 – 1.53
	Jan. 2003 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Remaining Term	Amount ($ millions)	Exchange Rate (US $/Cdn $)	Interest Rate (US $)	Interest Rate (Cdn $)
Currency swap	Jan. 2003 – Dec. 2005	US $125.0	1.55	7.69%	7.30%

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest rate				
Swaps – fixed into floating	Jan. 2003 – Jul. 2004	US $200.0	6.70%	LIBOR + 2.09%
	Jan. 2003 – Jul. 2006	US $200.0	6.70%	LIBOR + 1.58%
	Jan. 2003 – Jan. 2005	US $200.0	7.20%	LIBOR + 3.00%
	Jan. 2003 – Jan. 2007	US $200.0	7.20%	LIBOR + 2.23%
	Jan. 2003 – Oct. 2012	US $200.0	5.45%	LIBOR + 0.81%
Swaps – floating into fixed	Jan. 2003 – Mar. 2004	Cdn $100.0	5.08%	CDOR
	Jan. 2003 – Mar. 2007	Cdn $16.5	7.36%	CDOR

CREDIT RISK

Accounts receivable are mainly with customers in the oil and natural gas industry and are subject to normal industry credit risks. The Company minimizes this risk by entering into sales contracts with only highly rated entities. In addition, the Company reviews its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. The Company is also exposed to certain losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company minimizes this credit risk by entering into agreements with only highly rated financial institutions.

13. COMMITMENTS

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

	2003	2004	2005	2006	2007
Natural gas transportation charges	$ 192.0	$ 177.3	$ 159.6	$ 138.9	$ 111.7
Oil transportation and pipeline charges	$ 12.9	$ 14.6	$ 13.3	$ 13.2	$ 14.8
Offshore equipment operating lease charges	$ 71.6	$ 52.2	$ 48.9	$ 29.2	$ 29.2
Electricity charges	$ 33.2	$ 26.2	$ 25.3	$ 5.4	$ 5.2
Office lease charges	$ 17.1	$ 13.2	$ 12.2	$ 10.1	$ 10.1

14. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	2002	2001	2000
Interest paid	**$ 132.2**	$ 127.4	$ 169.3
Taxes paid	**$ 160.4**	$ 161.2	$ 62.3

15. SEGMENTED INFORMATION

The Company's oil and natural gas activities are conducted in three geographic segments: North America, the North Sea and Offshore West Africa. These activities relate to the exploration, development, production and marketing of oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment at December 31, 2002. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from oil and natural gas activities. There are currently no revenues for this project and all directly related expenditures have been capitalized.

	Oil and Natural Gas					
	North America			North Sea		
	2002	2001	2000	**2002**	2001	2000
Revenue						
Revenue	**$ 3,337.3**	$ 2,996.8	$ 2,905.1	**$ 592.4**	$ 523.0	$ 282.8
Less: royalties	**(564.2)**	(551.3)	(491.1)	**(32.7)**	(27.8)	(15.1)
	2,773.1	2,445.5	2,414.0	**559.7**	495.2	267.7
Expenses						
Production	**656.4**	596.4	492.0	**228.8**	123.3	54.9
Depletion, depreciation and amortization	**1,032.8**	747.1	585.9	**193.3**	129.0	54.4
Administration	**61.0**	37.1	26.4	**0.3**	0.5	0.8
Interest	**156.1**	129.7	155.5	**3.4**	8.3	6.8
Foreign exchange (gain) loss	**(52.7)**	59.7	14.3	**21.0**	1.6	3.2
Loss on sale of United States assets	**–**	24.1	–	**–**	–	–
	1,853.6	1,594.1	1,274.1	**446.8**	262.7	120.1
Earnings before taxes	**919.5**	851.4	1,139.9	**112.9**	232.5	147.6
Taxes other than income tax	**11.1**	8.5	12.3	**51.1**	59.1	33.3
Current income tax	**21.2**	15.1	14.7	**(19.6)**	61.8	33.7
Future income tax	**322.5**	290.4	466.5	**82.5**	(9.0)	(15.0)
Net earnings	**564.7**	537.4	646.4	**(1.1)**	120.6	95.6
Dividend on preferred securities, net of tax	**(6.0)**	(5.9)	(2.8)	**–**	–	–
Revaluation of preferred securities	**1.0**	(7.5)	(1.6)	**–**	–	–
Net earnings attributable to common shareholders	**$ 559.7**	$ 524.0	$ 642.0	**$ (1.1)**	$ 120.6	$ 95.6

CAPITAL EXPENDITURES

	2002				
	Cash Consideration	Non-cash Consideration	Capital Expenditures	Fair Value Adjustments [1]	Capitalized Costs
Oil and natural gas					
North America – business combination	**843.2**	**1,550.0**	**2,393.2**	**1,018.6**	**3,411.8**
North America – oil and natural gas	**1,026.3**	**–**	**1,026.3**	**–**	**1,026.3**
North Sea	**323.3**	**–**	**323.3**	**233.0**	**556.3**
Offshore West Africa	**185.3**	**–**	**185.3**	**–**	**185.3**
	2,378.1	**1,550.0**	**3,928.1**	**1,251.6**	**5,179.7**
Horizon Project	**68.1**	**–**	**68.1**	**–**	**68.1**
Midstream	**20.4**	**–**	**20.4**	**–**	**20.4**
Abandonments [2]	**42.9**	**–**	**42.9**	**–**	**42.9**
Other	**9.9**	**–**	**9.9**	**–**	**9.9**
	2,519.4	**1,550.0**	**4,069.4**	**1,251.6**	**5,321.0**

(1) Future income tax adjustments on non-tax base assets and other fair value adjustments.
(2) Abandonment expenditures were incurred in the following segments: $31.8 million North America, $8.6 million North Sea and $2.5 million Offshore West Africa (2001 – $9.4 million North America, $nil North Sea, $nil Offshore West Africa).

As a result of the Company's increasing midstream activities, the Company determined that effective January 1, 2002, the midstream activities within North America constitute a distinct operating segment. Midstream activities include the Company's pipeline operations and an electricity co-generation system.

Offshore West Africa			Midstream			Total		
2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
$ 101.5	$ 41.6	$ 34.6	**$ 52.0**	$ 27.4	$ 38.1	**$ 4,083.2**	$ 3,588.8	$ 3,260.6
(3.4)	(1.2)	–	**–**	–	–	**(600.3)**	(580.3)	(506.2)
98.1	40.4	34.6	**52.0**	27.4	38.1	**3,482.9**	3,008.5	2,754.4
34.6	27.0	15.4	**14.1**	11.2	8.7	**933.9**	757.9	571.0
80.5	23.9	2.5	**7.6**	3.8	1.8	**1,314.2**	903.8	644.6
–	–	–	**–**	–	–	**61.3**	37.6	27.2
(0.6)	(0.2)	–	**–**	–	–	**158.9**	137.8	162.3
–	1.5	(1.6)	**–**	–	–	**(31.7)**	62.8	15.9
–	–	–	**–**	–	–	**–**	24.1	–
114.5	52.2	16.3	**21.7**	15.0	10.5	**2,436.6**	1,924.0	1,421.0
(16.4)	(11.8)	18.3	**30.3**	12.4	27.6	**1,046.3**	1,084.5	1,333.4
0.7	1.5	3.9	**–**	–	–	**62.9**	69.1	49.5
6.0	–	–	**–**	–	–	**7.6**	76.9	48.4
(16.8)	(4.2)	0.4	**12.8**	5.3	12.1	**401.0**	282.5	464.0
(6.3)	(9.1)	14.0	**17.5**	7.1	15.5	**574.8**	656.0	771.5
–	–	–	**–**	–	–	**(6.0)**	(5.9)	(2.8)
–	–	–	**–**	–	–	**1.0**	(7.5)	(1.6)
$ (6.3)	$ (9.1)	$ 14.0	**$ 17.5**	$ 7.1	$ 15.5	**$ 569.8**	$ 642.6	$ 767.1

	2001				
	Cash Consideration	Non-cash Consideration	Capital Expenditures	Fair Value Adjustments [1]	Capitalized Costs
Oil and natural gas					
North America – business combination	–	–	–	–	–
North America – oil and natural gas	1,443.2	–	1,443.2	185.4	1,628.6
North Sea	97.5	–	97.5	–	97.5
Offshore West Africa	203.9	–	203.9	–	203.9
	1,744.6	–	1,744.6	185.4	1,930.0
Horizon Project	26.8	–	26.8	–	26.8
Midstream	97.3	–	97.3	5.0	102.3
Abandonments [2]	9.4	–	9.4	–	9.4
Other	6.4	–	6.4	–	6.4
	1,884.5	–	1,884.5	190.4	2,074.9

SEGMENTED PROPERTY, PLANT AND EQUIPMENT (NET)

	2002	2001
Oil and natural gas		
North America	**$ 10,252.0**	$ 6,807.6
North Sea	**1,277.0**	865.6
Offshore West Africa	**518.3**	409.9
Horizon Project	**228.7**	160.6
Midstream	**195.6**	182.8
Other	**28.0**	16.4
	$ 12,499.6	$ 8,442.9

SEGMENTED ASSETS

	2002	2001
Oil and natural gas		
North America	**$ 10,916.8**	$ 7,216.1
North Sea	**1,426.6**	941.0
Offshore West Africa	**549.4**	433.2
Horizon Project	**228.7**	160.6
Midstream	**209.4**	199.6
Other	**28.0**	16.4
	$ 13,358.9	$ 8,966.9

16. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2002	2001	2000
Net earnings – Canadian GAAP		**$ 574.8**	$ 656.0	$ 771.5
Adjustments, net of tax				
Depletion	**(A)**	**5.2**	5.1	5.1
Derivative financial instruments	**(B)**	**29.3**	60.9	(6.4)
Dividend on preferred securities	**(C)**	**(6.0)**	(5.9)	(2.8)
Revaluation of preferred securities	**(C)**	**1.0**	(7.5)	(1.6)
Tax effect of flow-through shares	**(D)**	**(1.0)**	–	–
Net earnings – US GAAP		**$ 603.3**	$ 708.6	$ 765.8
Net earnings – US GAAP per common share				
Basic		**$ 4.72**	$ 5.84	$ 6.56
Diluted		**$ 4.56**	$ 5.70	$ 6.38

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	2002	2001	2000
Net earnings – US GAAP		**$ 603.3**	$ 708.6	$ 765.8
Adoption of FAS 133	**(B)**	**–**	(124.5)	–
Amortization of FAS 133 adjustment	**(B)**	**31.1**	54.1	–
Foreign currency translation adjustment	**(E)**	**(49.2)**	72.8	–
Comprehensive income		**$ 585.2**	$ 711.0	$ 765.8

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

		2002		
(millions of Canadian dollars)	**Notes**	**Canadian GAAP**	**Increase (Decrease)**	**US GAAP**
Property, plant and equipment	**(A)**	**$ 12,499.6**	**$ (67.5)**	**$ 12,432.1**
Derivative financial instruments (asset)	**(B)**	**$ –**	**$ (56.4)**	**$ (56.4)**
Long-term debt	**(C)**	**$ 4,074.0**	**$ 126.4**	**$ 4,200.4**
Future income tax	**(A,B)**	**$ 3,187.4**	**$ 4.3**	**$ 3,191.7**
Shareholders' equity		**$ 4,868.1**	**$ (141.8)**	**$ 4,726.3**

		2001		
(millions of Canadian dollars)	Notes	Canadian GAAP	Increase (Decrease)	US GAAP
Property, plant and equipment	(A)	$ 8,442.9	$ (76.5)	$ 8,366.4
Derivative financial instruments liability	(B)	$ –	$ 32.2	$ 32.2
Long-term debt	(C)	$ 2,669.2	$ 127.4	$ 2,796.6
Future income tax	(A,B)	$ 1,767.3	$ (27.7)	$ 1,739.6
Shareholders' equity		$ 3,807.0	$ (208.4)	$ 3,598.6

NOTES:

(A) Using Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes and future site restoration costs, are limited to an amount equal to the undiscounted, unescalated future net revenues from proved reserves plus the lower of cost or estimated fair market value of unproved properties (the "ceiling test"). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are discounted at 10% and estimated future financing and administrative expenses are not deducted from net revenues.

(B) The Company uses certain derivative financial instruments to manage its commodity prices and foreign currency exposure in relation to future firmly committed and anticipated sales transactions. The Company has also used interest rate swaps to manage its interest rate exposure. Under Canadian GAAP, these derivative financial instruments are accounted for as hedges.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 "Accounting for Derivative Instruments and Hedging Activities" and FAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" to account for its commodity prices and interest rate swap derivative financial instruments under US GAAP. Under FAS 133, all derivative financial instruments are recognized in the consolidated balance sheets at their fair value. Changes in the fair value of derivative financial instruments are recognized in consolidated net earnings unless specific criteria for hedging are met. In 2002 and 2001, no derivative financial instruments were designated as hedges for US GAAP purposes.

In 2001, the adoption of FAS 133 resulted in the Company recognizing a derivative financial instruments liability of $183.4 million and a charge to comprehensive income of $124.5 million, net of future income tax recoveries of $58.9 million. Of the initial liability recognized on January 1, 2001, a loss of $54.1 million, net of future income tax recoveries of $25.6 million, was reclassified to net earnings during 2001. For 2002, a loss of $31.1 million, net of future income tax recoveries of $14.5 million, was reclassified to net earnings.

Under US GAAP, foreign currency swap contracts used to hedge foreign currency exposure to anticipated, but not firmly committed, transactions cannot be accounted for as hedges under FAS 52, "Foreign Currency Translation". Accordingly, for US GAAP reporting, gains and losses from changes in the fair market value of foreign currency swap contracts related to these anticipated transactions are recognized in net earnings when those changes in market value occur.

(C) Under Canadian GAAP, the preferred securities are considered to be equity because the Company has the unrestricted right to pay dividends, principal and principal prepayments with common shares. Under US GAAP, the Company's preferred securities would be classified as long-term debt rather than as equity. Accordingly, the dividend on the preferred securities would be classified as interest expense rather than as a dividend and the revaluation of preferred securities would be included in foreign exchange (gain) loss in determining consolidated net earnings.

(D) Under Canadian GAAP, the future income tax effect of flow-through shares is deducted from share capital. However, under US GAAP, the future income tax effect of flow-through shares is expensed immediately.

(E) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

(F) The Company has included transportation costs of $293.1 million, $84.2 million and $67.8 million as a reduction of oil and natural gas revenues for the years ended December 31, 2002, 2001 and 2000, respectively.

(G) Recently Issued Accounting Standards

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS

In January 2003, the Canadian Institute of Chartered Accountants ("CICA") issued Section 3063 "Impairment of Long-lived Assets". This Section indicates that impairment losses occur when the carrying value of the asset exceeds the sum of the undiscounted cash flows expected from its use and is measured as the amount by which the carrying amount exceeds its fair value. The effective date of the Section will be for fiscal years beginning on or after April 1, 2003. Application of the Section is prospective with earlier adoption encouraged. This Section will apply to the Company's midstream operating segment only.

ACCOUNTING FOR THE DISPOSAL OF LONG-LIVED ASSETS AND DISCONTINUED OPERATIONS

In January 2003, the CICA issued Section 3475 "Disposal of Long-lived Assets and Discontinued Operations". This Section outlines criteria for when a long-lived asset may be classified as held for sale and indicates that the value of such asset be measured at the lower of its carrying amount and fair value less cost to sell. The Section also indicates that losses recognized do not include any expected future operating losses. Discontinued operations will be defined more broadly than previously. The effective date of the Section will apply to disposal activities initiated on or after May 1, 2003.

HEDGING

In December 2001, the CICA issued Accounting Guideline 13, "Hedging Relationships". This Guideline addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirement to evaluate hedges for effectiveness. The Guideline does not specify how hedge accounting should be applied. The CICA has deferred the effective date of this Guideline by one year to fiscal years beginning on or after July 1, 2003. The Company is currently evaluating the impact of this Guideline on its consolidated financial statements.

ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

In June 2001, the Financial Accounting Standards Board ("FASB") issued FAS 143 "Accounting for Asset Retirement Obligations". FAS 143 requires the recognition of the fair value of the retirement obligation for related long-lived tangible assets as a liability. Retirement costs equal to the retirement liability are capitalized as part of the cost of the related capital asset and amortized to expense over the life of the asset. This Standard is effective for fiscal years beginning on or after June 25, 2002. Adoption of this Standard may result in an adjustment to the future site restoration liability and to property, plant and equipment on the Company's consolidated balance sheets. The Canadian Accounting Standards Board (AcSB) has proposed a similar standard, which will be applicable for fiscal years beginning on or after January 1, 2004.

ACCOUNTING FOR COSTS ASSOCIATED WITH EXIT OR DISPOSAL ACTIVITIES

In July 2002, the FASB issued FAS 146, "Accounting for Costs Associated with Exit or Disposal Activities" to replace Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)". FAS 146 requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of commitment to an exit or disposal plan. The Standard is effective for exit or disposal activities initiated after December 31, 2002.

ACCOUNTING GUIDANCE TO IMPROVE DISCLOSURE REQUIREMENTS FOR GUARANTEES

In November 2002, the FASB published Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others". The Interpretation expands on FAS 5, "Accounting for Contingencies", FAS 57, "Related Party Disclosures" and FAS 107, "Disclosures about Fair Value of Financial Instruments". It also incorporates, without change, Interpretation No. 34, "Disclosure of Indirect Guarantees". The Interpretation elaborates on the existing disclosure requirements for most guarantees. It also clarifies that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee and must disclose that information in its interim and annual financial statements. The Interpretation is to be applied on a prospective basis to guarantees issued or modified after December 31, 2002, except for the disclosure requirements that are effective for interim or annual financial statements with periods ending after December 15, 2002. The Company is currently evaluating the impact of this Interpretation on its consolidated financial statements.

supplementary oil & gas information (unaudited)

This supplementary oil and natural gas information is provided in accordance with the United States FAS 69, "Disclosures about Oil and Gas Producing Activities", and where applicable, is reconciled to the US GAAP financial information.

NET PROVED OIL AND NATURAL GAS RESERVES

The Company retains independent petroleum engineering consultants to evaluate the majority of the Company's proved oil and natural gas reserves, with the remainder evaluated by the Company's internal petroleum engineers.

- For the year ended December 31, 2002, the reports by Sproule Associates Limited ("Sproule") covered 89% of the Company's reserves.
- For the year ended December 31, 2001, the reports by Sproule covered 91% of the Company's reserves.
- For the year ended December 31, 2000, reports by Sproule (Canadian assets), Ryder Scott Company (US assets) and AEA Technology (international assets) covered 98% of the Company's reserves.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed oil and natural gas reserves, net of royalties, as at December 31, 2002, 2001 and 2000:

Oil and Natural Gas Liquids

(mmbbls)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 1999	501	–	–	501
Extensions and discoveries	59	–	–	59
Purchases of reserves in place	68	97	30	195
Sales of reserves in place	(13)	–	–	(13)
Production	(51)	(6)	(1)	(58)
Revisions of previous estimates	4	2	1	7
Reserves, December 31, 2000	568	93	30	691
Extensions and discoveries	13	–	37	50
Purchases of reserves in place	14	–	8	22
Sales of reserves in place	(1)	–	–	(1)
Production	(54)	(13)	(1)	(68)
Revisions of previous estimates	43	(2)	(14)	27
Reserves, December 31, 2001	583	78	60	721
Extensions and discoveries	**26**	**1**	**14**	**41**
Purchases of reserves in place	**44**	**114**	**–**	**158**
Sales of reserves in place	**(1)**	**(18)**	**–**	**(19)**
Production	**(55)**	**(13)**	**(2)**	**(70)**
Revisions of previous estimates	**(26)**	**40**	**3**	**17**
Reserves, December 31, 2002	**571**	**202**	**75**	**848**
Net proved developed reserves:				
December 31, 1999	299	–	–	299
December 31, 2000	328	61	2	391
December 31, 2001	344	51	20	415
December 31, 2002	**340**	**107**	**27**	**474**

supplementary oil & gas information (unaudited)

Natural Gas

(bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 1999	1,771	–	–	1,771
Extensions and discoveries	201	–	–	201
Purchases of reserves in place	214	89	52	355
Sales of reserves in place	(33)	–	–	(33)
Production	(226)	(1)	–	(227)
Revisions of previous estimates	(32)	3	1	(28)
Reserves, December 31, 2000	1,895	91	53	2,039
Extensions and discoveries	379	–	–	379
Purchases of reserves in place	134	–	23	157
Sales of reserves in place	(20)	–	–	(20)
Production	(255)	(4)	–	(259)
Revisions of previous estimates	(69)	7	(9)	(71)
Reserves, December 31, 2001	2,064	94	67	2,225
Extensions and discoveries	**106**	**–**	**4**	**110**
Purchases of reserves in place	**699**	**18**	**–**	**717**
Sales of reserves in place	**(3)**	**(56)**	**–**	**(59)**
Production	**(346)**	**(10)**	**(1)**	**(357)**
Revision of previous estimates	**(74)**	**25**	**1**	**(48)**
Reserves, December 31, 2002	**2,446**	**71**	**71**	**2,588**
Net proved developed reserves:				
December 31, 1999	1,466	–	–	1,466
December 31, 2000	1,569	32	–	1,601
December 31, 2001	1,845	19	16	1,880
December 31, 2002	**2,185**	**57**	**27**	**2,269**

CAPITALIZED COSTS RELATED TO OIL AND NATURAL GAS ACTIVITIES

	2002			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Proved properties	**$ 13,196.5**	**$ 1,559.2**	**$ 480.1**	**$ 15,235.8**
Unproved properties	**666.8**	**62.0**	**131.8**	**860.6**
	13,863.3	**1,621.2**	**611.9**	**16,096.4**
Less: accumulated depletion and depreciation	**(3,678.8)**	**(344.2)**	**(93.6)**	**(4,116.6)**
Net capitalized costs	**$ 10,184.5**	**$ 1,277.0**	**$ 518.3**	**$ 11,979.8**

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 9,000.7	$ 990.7	$ 376.8	$ 10,368.2
Unproved properties	424.0	59.6	48.4	532.0
	9,424.7	1,050.3	425.2	10,900.2
Less: accumulated depletion and depreciation	(2,693.6)	(184.7)	(15.3)	(2,893.6)
Net capitalized costs	$ 6,731.1	$ 865.6	$ 409.9	$ 8,006.6

	2000			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 7,422.8	$ 822.8	$ 206.5	$ 8,452.1
Unproved properties	382.5	45.5	14.8	442.8
	7,805.3	868.3	221.3	8,894.9
Less: accumulated depletion and depreciation	(1,998.9)	(52.3)	(0.9)	(2,052.1)
Net capitalized costs	$ 5,806.4	$ 816.0	$ 220.4	$ 6,842.8

COSTS INCURRED IN OIL AND NATURAL GAS ACTIVITIES

	2002			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Property acquisitions				
Proved	**$ 3,366.6**	**$ 373.1**	**$ –**	**$ 3,739.7**
Unproved	**368.9**	**27.8**	**30.5**	**427.2**
Exploration	**96.0**	**10.4**	**80.5**	**186.9**
Development	**606.6**	**145.0**	**74.3**	**825.9**
Costs incurred	**$ 4,438.1**	**$ 556.3**	**$ 185.3**	**$ 5,179.7**

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Property acquisitions				
Proved	$ 647.2	$ –	$ 62.4	$ 709.6
Unproved	73.0	4.5	–	77.5
Exploration	60.9	24.7	63.7	149.3
Development	847.5	68.3	77.8	993.6
Costs incurred	$ 1,628.6	$ 97.5	$ 203.9	$ 1,930.0

	2000			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Property acquisitions				
Proved	$ 649.6	$ 768.2	$ 182.0	$ 1,599.8
Unproved	137.2	45.3	–	182.5
Exploration	47.9	2.7	15.9	66.5
Development	770.3	52.1	23.4	845.8
Costs incurred	$ 1,605.0	$ 868.3	$ 221.3	$ 2,694.6

RESULTS OF OPERATIONS FROM OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from oil and natural gas producing activities for the years ended December 31, 2002, 2001 and 2000 are summarized in the following tables:

	2002			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Oil and natural gas revenue, net of royalties	**$ 2,772.1**	**$ 559.2**	**$ 98.1**	**$ 3,429.4**
Production expenses	**(656.4)**	**(228.8)**	**(34.6)**	**(919.8)**
Depletion, depreciation and amortization	**(1,032.8)**	**(193.3)**	**(80.5)**	**(1,306.6)**
Income tax	**(344.4)**	**(82.3)**	**16.8**	**(409.9)**
Results of operations	**$ 738.5**	**$ 54.8**	**$ (0.2)**	**$ 793.1**

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 2,443.8	$ 495.1	$ 40.4	$ 2,979.3
Production expenses	(596.4)	(123.3)	(27.0)	(746.7)
Depletion, depreciation and amortization	(747.2)	(129.0)	(23.9)	(900.1)
Income tax	(353.2)	(114.2)	2.7	(464.7)
Results of operations	$ 747.0	$ 128.6	$ (7.8)	$ 867.8

	2000			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 2,413.1	$ 267.7	$ 34.6	$ 2,715.4
Production expenses	(492.0)	(54.9)	(15.4)	(562.3)
Depletion, depreciation and amortization	(585.9)	(54.4)	(2.5)	(642.8)
Income tax	(448.4)	(70.8)	(4.3)	(523.5)
Results of operations	$ 886.8	$ 87.6	$ 12.4	$ 986.8

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved oil and natural gas reserves has been computed using year-end sales prices and costs and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows.

supplementary oil & gas information (unaudited)

The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and potential reserves;
- Future production of oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end sales prices and costs will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future development and site restoration costs will differ from those estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above.

The following tables summarize the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure as prescribed in FAS 69:

	2002			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	**$ 34,979.7**	**$ 9,681.6**	**$ 4,147.1**	**$ 48,808.4**
Future production costs	**(7,238.0)**	**(3,249.6)**	**(911.0)**	**(11,398.6)**
Future development and site restoration costs	**(1,769.9)**	**(1,691.2)**	**(616.2)**	**(4,077.3)**
Future income taxes	**(8,045.5)**	**(2,990.7)**	**(941.6)**	**(11,977.8)**
Future net cash flows	**17,926.3**	**1,750.1**	**1,678.3**	**21,354.7**
10% annual discount for timing of future cash flows	**(7,361.3)**	**(433.6)**	**(555.7)**	**(8,350.6)**
Standardized measure of future net cash flows	**$ 10,565.0**	**$ 1,316.5**	**$ 1,122.6**	**$ 13,004.1**

	2001			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 18,565.1	$ 3,089.0	$ 1,738.4	$ 23,392.5
Future production costs	(6,587.4)	(1,367.8)	(575.6)	(8,530.8)
Future development and site restoration costs	(1,203.8)	(354.3)	(555.5)	(2,113.6)
Future income taxes	(2,575.8)	(548.5)	(136.1)	(3,260.4)
Future net cash flows	8,198.1	818.4	471.2	9,487.7
10% annual discount for timing of future cash flows	(3,136.3)	(241.4)	(148.5)	(3,526.2)
Standardized measure of future net cash flows	$ 5,061.8	$ 577.0	$ 322.7	$ 5,961.5

	2000			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 33,126.7	$ 3,999.2	$ 1,209.9	$ 38,335.8
Future production costs	(5,997.7)	(1,701.7)	(376.5)	(8,075.9)
Future development and site restoration costs	(1,269.9)	(426.9)	(179.4)	(1,876.2)
Future income taxes	(8,039.7)	(766.1)	(232.4)	(9,038.2)
Future net cash flows	17,819.4	1,104.5	421.6	19,345.5
10% annual discount for timing of future cash flows	(6,988.7)	(366.2)	(111.5)	(7,466.4)
Standardized measure of future net cash flows	$ 10,830.7	$ 738.3	$ 310.1	$ 11,879.1

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2002**	2001	2000
Sales of oil and natural gas produced, net of production costs	**$ (1,439.6)**	$ (1,411.7)	$ (1,328.0)
Net changes in sales prices and production costs	**8,823.7**	(9,624.6)	5,615.7
Extensions, discoveries and improved recovery	**1,078.7**	1,070.6	1,740.0
Changes in estimated future development costs	**(1,283.8)**	(165.6)	(678.2)
Purchases of proved reserves in place	**4,973.1**	426.1	4,078.0
Sales of proved reserves in place	**(494.0)**	(34.2)	(319.4)
Revisions of previous reserve estimates [(1)]	**383.8**	38.5	(84.7)
Accretion of discount	**803.2**	1,744.8	810.2
Changes in production timing and other	**(560.3)**	(1,554.5)	(560.4)
Net change in income taxes	**(5,242.2)**	3,593.0	(3,223.0)
Net change	**7,042.6**	(5,917.6)	6,050.2
Balance – beginning of year	**5,961.5**	11,879.1	5,828.9
Balance – end of year	**$ 13,004.1**	$ 5,961.5	$ 11,879.1

(1) 2002 revisions include the effects of eliminating UK royalties.

ten-year review

Years ended December 31	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
FINANCIAL INFORMATION ($ millions, except per share amounts)										
Revenue, net of royalties [1]	**3,482.9**	3,008.5	2,754.4	1,103.6	760.8	768.7	532.3	245.4	221.2	135.5
Cash flow from operations attributable to common shareholders	**2,254.0**	1,920.0	1,883.6	723.5	444.2	503.0	359.7	153.6	152.8	94.2
Per common share – basic	**$ 17.63**	$ 15.83	$ 16.14	$ 6.96	$ 4.47	$ 5.13	$ 4.32	$ 2.22	$ 2.39	$ 1.64
Net earnings attributable to common shareholders [2]	**569.8**	642.6	767.1	219.5	39.4	111.3	95.0	42.4	54.2	34.3
Per common share – basic [2]	**$ 4.46**	$ 5.30	$ 6.57	$ 2.11	$ 0.40	$ 1.14	$ 1.14	$ 0.61	$ 0.85	$ 0.60
Capital expenditures, net of dispositions (including business combinations)	**4,069.4**	1,884.5	2,823.3	1,900.6	609.7	1,119.2	1,203.6	238.8	331.2	271.2
Balance Sheet Information										
Working capital (deficiency) surplus	**(13.8)**	(5.6)	(77.3)	36.4	57.9	(18.6)	(0.8)	9.7	4.0	2.2
Property, plant and equipment, net	**12,499.6**	8,442.9	7,141.5	4,553.5	3,033.6	2,746.0	1,912.0	836.4	677.5	401.1
Total assets	**13,358.9**	8,966.9	7,753.5	4,850.8	3,227.8	2,931.1	2,062.6	900.4	737.8	436.9
Long-term debt	**4,074.0**	2,669.2	2,454.5	2,156.8	1,425.5	1,136.3	588.0	237.7	242.9	189.2
Shareholders' equity	**4,868.1**	3,807.0	3,203.1	1,891.7	1,257.8	1,204.3	1,074.2	496.3	356.2	171.2
SHARE INFORMATION										
Common shares outstanding (thousands)	**133,776**	121,201	122,279	111,454	99,809	98,819	97,383	74,074	66,709	59,862
Weighted average shares outstanding (thousands)	**127,883**	121,300	116,701	103,906	99,331	98,042	83,246	69,319	63,873	57,596
Dividend per common share	**$ 0.50**	$ 0.40	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –
Trading Statistics										
TSX – Cdn $										
Trading volume (thousands)	**154,829**	133,744	141,853	107,615	102,610	100,538	99,222	60,935	35,291	55,218
Share price ($/share)										
High	**$ 54.54**	$ 52.35	$ 56.20	$ 38.60	$ 31.50	$ 44.25	$ 39.40	$ 20.25	$ 22.75	$ 25.00
Low	**$ 37.60**	$ 35.90	$ 29.80	$ 19.80	$ 18.25	$ 28.90	$ 19.25	$ 10.75	$ 13.38	$ 10.88
Close	**$ 46.80**	$ 38.31	$ 41.50	$ 35.25	$ 23.00	$ 30.60	$ 37.60	$ 20.00	$ 13.75	$ 18.00
NYSE – US $										
Trading volume (thousands)	**7,966**	5,191	793	–	–	–	–	–	–	–
Share price ($/share)										
High	**$ 34.88**	$ 34.51	$ 37.81	$ –	$ –	$ –	$ –	$ –	$ –	$ –
Low	**$ 23.55**	$ 22.80	$ 24.75	$ –	$ –	$ –	$ –	$ –	$ –	$ –
Close	**$ 29.67**	$ 24.40	$ 27.50	$ –	$ –	$ –	$ –	$ –	$ –	$ –
RATIOS										
Debt to cash flow	**1.8x**	1.4x	1.3x	3.0x	3.2x	2.3x	1.6x	1.5x	1.6x	2.0x
Debt to book capitalization	**45.6%**	41.2%	43.4%	53.3%	53.1%	48.5%	35.4%	32.4%	40.5%	52.5%
Return on average common shareholders' equity, after tax	**13.8%**	18.8%	31.6%	14.5%	3.2%	9.8%	13.0%	10.3%	19.7%	26.3%
Daily production per thousand common shares (boe/d)	**3.29**	2.96	2.62	1.99	1.89	1.78	1.45	0.98	0.82	0.62
Reserves per common share (boe)	**13.39**	12.22	11.49	9.55	7.55	7.09	5.32	3.58	3.53	2.85
Net asset value per common share	**$ 78.55**	$ 70.02	$ 87.43	$ 48.61	$ 31.74	$ 27.40	$ 25.84	$18.40	$ 15.11	$ 13.81

(1) Restated to conform to current year presentation.
(2) Restated for change in accounting policy (see consolidated financial statements - note 2).

ten-year review

Years ended December 31	2002	2001	2000	1999	1998	1997	1996	1995	1994	1993
OPERATING INFORMATION										
Oil and Liquids (mmbbls)										
Proved reserves										
North America	**665**	644	642	554	287	270	141	53	43	29
North Sea	**200**	85	102	–	–	–	–	–	–	–
Offshore West Africa	**96**	61	37	–	–	–	–	–	–	–
	961	790	781	554	287	270	141	53	43	29
Probable reserves										
North America	**77**	95	88	86	97	81	50	24	14	14
North Sea	**73**	23	33	–	–	–	–	–	–	–
Offshore West Africa	**70**	51	9	–	–	–	–	–	–	–
	220	169	130	86	97	81	50	24	14	14
	1,181	959	911	640	384	351	191	77	57	43
Natural Gas (bcf)										
Proved reserves										
North America	**3,048**	2,566	2,360	2,183	1,905	1,733	1,605	924	894	666
North Sea	**71**	94	91	–	–	–	–	–	–	–
Offshore West Africa	**90**	69	66	–	–	–	–	–	–	–
	3,209	2,729	2,517	2,183	1,905	1,733	1,605	924	894	666
Probable reserves										
North America	**402**	349	402	364	311	363	362	208	175	101
North Sea	**18**	24	23	–	–	–	–	–	–	–
Offshore West Africa	**31**	27	19	–	–	–	–	–	–	–
	451	400	444	364	311	363	362	208	175	101
	3,660	3,129	2,961	2,547	2,216	2,096	1,967	1,132	1,069	767
Total Reserves (mmboe)	**1,791**	1,481	1,405	1,065	753	700	519	266	235	171
Daily Production										
Oil and liquids (mbbls/d)										
North America	**169**	167	155	87	76	71	37	17	13	8
North Sea	**39**	36	17	–	–	–	–	–	–	–
Offshore West Africa	**7**	3	2	–	–	–	–	–	–	–
	215	206	174	87	76	71	37	17	13	8
Natural gas (mmcf/d)										
North America	**1,204**	906	793	721	673	626	499	305	238	165
North Sea	**27**	12	1	–	–	–	–	–	–	–
Offshore West Africa	**1**	–	–	–	–	–	–	–	–	–
	1,232	918	794	721	673	626	499	305	238	165
Total Production (mboe/d)	**421**	359	306	207	188	175	120	68	53	36
Product Pricing										
Average oil and liquid price ($/bbl)	**29.76**	24.31	29.99	21.04	12.93	18.82	23.52	19.82	18.18	18.17
Average natural gas price ($/mcf)	**3.76**	5.16	4.53	2.36	2.12	1.91	1.71	1.43	1.99	1.72

corporate information

BOARD OF DIRECTORS

N. Murray Edwards
President,
Edco Financial Holdings Ltd.
Calgary, Alberta

Ambassador Gordon D. Giffin
Senior Partner,
McKenna Long & Aldridge LLP
Atlanta, Georgia

James T. Grenon
Managing Director,
TOM Capital Associates Inc.
Calgary, Alberta

John G. Langille
President,
Canadian Natural Resources Limited
Calgary, Alberta

Keith A. J. MacPhail
President & C.E.O.,
Bonavista Petroleum Ltd.
Calgary, Alberta

Allan P. Markin
Chairman of the Board,
Canadian Natural Resources Limited
Calgary, Alberta

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Chairman,
Burnet, Duckworth & Palmer
Calgary, Alberta

Eldon R. Smith, M.D.
Professor and Former Dean,
Faculty of Medicine,
The University of Calgary
Calgary, Alberta

David A. Tuer
Chairman,
Calgary Health Region
Calgary, Alberta

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James T. Grenon
James S. Palmer

COMPENSATION COMMITTEE

James S. Palmer – Chairman (1)
James T. Grenon
Eldon R. Smith

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Ambassador Gordon D. Giffin – Chairman (1)
James S. Palmer
David A. Tuer

RESERVES COMMITTEE

David A. Tuer – Chairman (1)
N. Murray Edwards
Keith A. J. MacPhail
James S. Palmer

SAFETY, HEALTH AND ENVIRONMENTAL COMMITTEE

Eldon R. Smith – Chairman (1)
N. Murray Edwards
Keith A.J. MacPhail

(1) Defined as Unrelated under the Corporate Governance Guidelines issued by the Toronto Stock Exchange; and defined as Independent under the United States Sarbanes-Oxley Act of 2002, and the proposed listing standards of the New York Stock Exchange.

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

EVALUATION ENGINEERS

Sproule Associates Limited
Calgary, Alberta

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John G. Langille
President

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Chief Operating Officer

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Réal J. H. Doucet
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Cameron S. Kramer
Vice-President, Field Operations

Bruce E. McGrath
Corporate Secretary

STOCK EXCHANGE SYMBOL

Toronto Stock Exchange
CNQ

New York Stock Exchange
CNQ

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