

Canadian Natural

Q1 Three Months Ended March 31, 2005

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD NATURAL GAS PRODUCTION AND STRONG FIRST QUARTER RESULTS

In commenting on first quarter 2005 results, Canadian Natural's Chairman, Allan Markin, stated "This was a significant quarter for Canadian Natural. Our Board of Directors sanctioned our world-class Horizon Oil Sands Project and in doing so provided even greater clarity on our defined plan for profitable growth. In turn, our expanded hedging strategy enables us to confidently move forward with 100% working interest ownership in the Horizon Project without financially compromising any of our conventional crude oil and natural gas projects. While the accounting conventions require us to recognize differences between our hedged prices and point-in-time commodity strip prices, I continue to believe that this strategy is prudent, allowing us to pursue our development programs without taking on undue financial risk."

Steve Laut, recently appointed President and Chief Operating Officer of Canadian Natural added, "Our first quarter drilling activities represented the second largest North American natural gas campaign in our history and resulted in 5% organic production growth on a quarter over quarter basis. Many of our contracted rigs are continuing on with our summer heavy crude oil drilling campaign. This efficient type of rig utilization helps us to control services costs in today's inflationary environment. Internationally, our new Floating Production Storage and Offtake vessel has arrived at the Baobab Field and we expect first oil within the next two months. Construction on our Horizon Oil Sands Project also continues on budget and on schedule. We continue to deliver on each of our major projects while maintaining strong cost control and financial discipline."

HIGHLIGHTS

($ millions, except per share amounts)		**Q1/05**		Q4/04		Q1/04
Net earnings (loss)	**$**	**(424)**	$	577	$	258
per common share, basic	**$**	**(1.58)**	$	2.15	$	0.96
Adjusted net earnings from operations[(1)]	**$**	**380**	$	321	$	339
per common share, basic	**$**	**1.42**	$	1.20	$	1.27
Cash flow from operations[(2)]	**$**	**1,009**	$	950	$	848
per common share, basic	**$**	**3.76**	$	3.54	$	3.16
Capital expenditures, net of dispositions	**$**	**1,372**	$	1,421	$	1,493
Debt to book capitalization		**37%**		34%		34%
Daily production, before royalties						
Natural gas (mmcf/d)		**1,455**		1,410		1,294
Crude oil and NGLs (mbbl/d)		**287.8**		295.7		261.3
Equivalent production (mboe/d)		**530.3**		530.7		476.9

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance and that of its business segments. The derivation of this item is shown on page 11 in the MD&A.

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates its ability to capital reinvestment and debt repayment. The derivation of this item is shown on page 12 in the MD&A.

- Strong quarterly natural gas growth resulted in record natural gas production levels and maintained record barrel of oil equivalent production levels. Quarterly natural gas production represents 46% of equivalent production and 53% of Canadian equivalent production. Canadian natural gas production during Q1/05 was 5% higher than Q4/04 and 16% higher than Q1/04.
- Strong cash flow generation during Q1/05 of over $1 billion, a 6% improvement over Q4/04 and 19% improvement over Q1/04.
- Quarterly loss of $424 million included charges of:
  - $679 million after tax for mark-to-market of commodity hedge position, effectively recognizing commodity strip price strength at March 31 for hedged production for the years 2005 and 2006 into the current quarter,
  - $125 million after tax for revaluation of potential stock option liability to reflect 33% stock price appreciation.
- Strong quarterly adjusted earnings from operations of $380 million, representing a 12% increase over Q1/04 and 18% increase over Q4/04.
- Successful quarterly drilling program of 503 net wells, excluding stratigraphic test and service wells, with an 89% success ratio, reflecting Canadian Natural's strong, low risk asset base.
- Net undeveloped land base in Canada of 11.3 million net acres – a key asset in today's highly competitive industry.
- Horizon Oil Sands Project received project sanction from Canadian Natural's Board of Directors on February 9, 2005. As a result of the sanctioning, the Company reported 1.9 billion barrels of proved bitumen mining reserves before royalties and 3.3 billion barrels of proved and probable bitumen mining reserves before royalties for the Horizon Oil Sands Project, as determined by independent qualified reserves evaluators Gilbert Laustsen Jung Associates Ltd. ("GLJ").
- Horizon Oil Sands Project remained on budget and on schedule with winter construction work completed as planned.
- The Floating Production Storage and Offtake ("FPSO") vessel for Baobab arrived during quarter and is preparing for first oil in mid 2005.
- Strong balance sheet with debt to book capitalization of 37%. First quarter capital expenditures, which represents 30% of 2005 total year capital budget, reflect the large natural gas drilling program on lands with winter only access.
- Subsequent to quarter end, announced the disposition of a large portion of its overriding royalty interests for proceeds of approximately $345 million. The transaction is expected to close on or about May 10, 2005. Pro forma the closing of the transaction, debt to book capitalization would amount to 35% at March 31, 2005.
- The 2005 first quarter dividend was increased 12.5% from $0.10 per common share to $0.1125 per common share.
- The Normal Course Issuer Bid has been extended to January 2006, allowing for the repurchase of up to 13.4 million shares through facilities of the Toronto Stock Exchange and the New York Stock Exchange. To date, no common shares have been repurchased under this program.

CORPORATE UPDATE

Effective immediately, the Company's Board of Directors are pleased to announce the appointments of Mr. John Langille as Vice-Chairman, Mr. Steve Laut as President & Chief Operating Officer and Mr. Doug Proll as Senior Vice-President, Finance & Chief Financial Officer. These appointments reflect the strong management resources available to the Company and the flexible management structure that has enabled Canadian Natural to grow so successfully over the past sixteen years.

Each of Mr. Langille, Mr. Laut and Mr. Proll will remain members of the Corporate Management Committee, which is responsible for setting Company strategy. Mr. Laut will oversee all operational activities of the Company while Mr. Proll will oversee the Company's financial accountability, information services and human resource functions.

The Board of Directors reluctantly accepted the resignation of Ambassador Frank McKenna from the Board of Directors following his appointment as Canada's ambassador to the United States. Mr. McKenna had been a Director of the Company since September 2004. The Company would like to thank Mr. McKenna for his brief, but dedicated service.

OPERATIONS REVIEW

In order to facilitate efficient operations, Canadian Natural focuses its activities into core regions where it can dominate the land base and infrastructure. Undeveloped land is critical to our ongoing growth and development within these core regions. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure the Company is able to maximize utilization of its production facilities, thereby increasing control over operating costs.

Activity by core region

	Net undeveloped land as at Mar 31, 2005 (thousands of net acres)	**Drilling activity Three months ended Mar 31, 2005 (net wells)**
Northeast British Columbia	**1,962**	**190**
Northwest Alberta	**1,701**	**73**
Northern Plains	**6,716**	**269**
Southern Plains	**635**	**22**
Southeast Saskatchewan	**121**	**12**
Horizon Oil Sands Project	**116**	**122**
United Kingdom North Sea	**563**	**2**
Offshore West Africa	**886**	**1**
	12,700	**691**

Drilling activity (number of wells)

	Three months ended March 31			
	2005		2004	
	Gross	**Net**	Gross	Net
Crude oil	**130**	**109**	148	143
Natural gas	**380**	**338**	395	358
Dry	**64**	**56**	74	70
Subtotal	**574**	**503**	617	571
Stratigraphic test / service wells	**188**	**188**	269	268
Total	**762**	**691**	886	839
Success rate (excluding stratigraphic test / service wells)		**89%**		88%

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Equivalent production	**Q1/05**		Q4/04		Q1/04	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**242.5**	**46**	235.0	44	215.6	45
Light crude oil and NGLs	**132.6**	**25**	129.2	24	117.1	25
Pelican Lake crude oil	**17.9**	**3**	19.1	4	19.9	4
Primary heavy crude oil	**92.0**	**17**	93.7	18	89.8	19
Thermal heavy crude oil	**45.3**	**9**	53.7	10	34.5	7
Total	**530.3**	**100**	530.7	100	476.9	100

North American natural gas

	Q1/05	Q4/04	Q1/04
Natural gas production (mmcf/d)	**1,430**	1,365	1,230
Net wells targeting natural gas	**386**	162	424
Net successful wells drilled	**338**	152	358
Success rate	**88%**	94%	84%

- Results benefited from a detailed and sequential drilling program that facilitated the procurement of effective drilling rigs and crews for the winter season, both of which are an integral part of cost control in an inflationary environment. Through this process, about 10 fewer drill rigs were used in Q1/05 in comparison to Q1/04 despite drilling a similar number of wells. Drilling plan and tie-ins were essentially completed according to plan, even with warmer than normal winter weather.
- High success rate reflected an exploitation approach and the high quality nature of land inventory. Drilling program was concentrated in winter-access only areas, with 186 wells in Northeast British Columbia, 71 wells in Northwest Alberta and 109 wells in the Northern Plains.
- Having large land inventories in the Company's core regions results in a competitive advantage given price escalation in industry land sales.
- Sequential quarterly natural gas production growth of 5% reflects organic activities. Year over year production growth of 16% is comprised of approximately 4% organic growth from Q1/04 to Q1/05 with the balance representing accretive acquisitions completed during 2004.
- Q2/05 drilling activity will be reduced from Q1/05 due to the winter-only access nature of the business and is consistent with prior years. Current North American production levels of approximately 1,500 mmcf/d will result in second quarter production of 1,455 mmcf/d to 1,485 mmcf/d, generally representing the Company's peak production levels for the year. The Company expects to drill approximately 64 natural gas wells during Q2/05.

North American crude oil and NGLs

	Q1/05	Q4/04	Q1/04
Crude oil and NGLs production (mbbl/d)	**209**	214	192
Net wells drilled targeting crude oil	**114**	107	143
Net successful wells drilled	**106**	105	140
Success rate	**93%**	98%	98%

- Q1/05 crude oil drilling activity was concentrated in the Northern Plains with 96 net crude oil wells.
- Canadian Natural continues the development of its vast heavy crude oil resources. As has been previously articulated, the development of these assets will be brought on stream as the demand for heavy crude oil markets permit. In addition, the Company seeks to actively increase available markets for its products through:
  - the potential expansion of markets through crude oil blending initiatives;
  - working with refiners to advance expansions of heavy crude oil conversion capacity of refineries in the Midwest United States; and,
  - working with pipeline companies to gain access to new North American and world-wide markets.
- The Company has committed to 25 mbbl/d of new pipeline capacity on the reversal of the Corsicana Pipeline, which will carry crude oil from the terminus of the current pipeline sales lines at Patoka, Illinois to the east Texas refining complex near Beaumont. This pipeline is expected to be commissioned for service in late 2005.
- The Company is contributing 125 mbbl/d of heavier crude oil blends to the Western Canadian Select ("WCS") stream.
- Primary heavy crude oil production decreased slightly from Q4/04 reflecting the disciplined drilling approach that the Company employs. Drill rigs utilized for natural gas in winter-access only areas are migrated into the heavy crude oil regions during the second quarter, enabling a high rig utilization rate and the effective use of highly trained rig crews. The second quarter drilling activity will include approximately 82 primary heavy wells. This drilling activity will yield production increases in the third quarter as primary heavy crude oil wells typically ramp production through the first six months of their productive lives.
- The Primrose field expansion continued with the drilling of 16 wells. Production from these pads is subject to the cycling of steam injection and crude oil production; therefore, due to such normal cycling activities, average production levels in Q1/2005 were lower than Q4/2004.
- The Primrose expansion continues to be on track and on budget with total capital expenditures of approximately $300 million expected to be incurred, leading to first oil of 30 mbbl/d in 2006.
- The Pelican Lake waterflood expansion was successfully continued during the quarter with 30 wells being converted into water injectors. Production levels remained essentially flat with the prior quarter as a result of this activity as well as the drilling of 15 producer wells. The Pelican Lake polymer flood pilot test has just been initiated with facilities having been installed in April.

International

The Company operates in the North Sea and Offshore West Africa where production of lighter quality crude oil is targeted, but natural gas may be produced in association with crude oil production. Natural gas typically comprises less than 10% of boe production.

	Q1/05	Q4/04	Q1/04
Total equivalent production (mboe/d)			
North Sea	**75**	77	66
Offshore West Africa	**8**	12	14
Net wells drilled targeting crude oil	**2.9**	4.0	3.5
Net successful wells drilled	**2.3**	2.3	3.5
Success rate	**79%**	58%	100%

North Sea

- Canadian Natural continues to utilize its mature basin expertise, and will continue to target accretive acquisitions with exploitation upside potential.
- During Q1/05, 1.7 net wells were drilled and completed with an additional three net wells drilling at quarter end.
- Following an unplanned extended shutdown on a Ninian platform, repairs to a power turbine used to drive water injection resulted in a loss of pressure to the reservoir. Remedial work was completed in the first quarter. With water injection back to capacity and two new wells completed, production is recovering. Ninian production averaged 17 mbbl/d during the first quarter. Current production levels are 22 mbbl/d.
- Canadian Natural completed the natural gas reinjection project at the Banff Field in the Central North Sea in late 2004. This project could ultimately increase overall reservoir recovery by approximately 17 mmbbl net to Canadian Natural, and has resulted in reduced natural gas sales of approximately 30 mmcf/d. Results to date are positive, although full production benefit has been constrained by facilities capacity.
- The major refurbishment of the Tiffany platform drilling rig is near completion, which will facilitate a two well program commencing in Q2/05. In addition, on Thelma, two wells are scheduled to spud later this year targeting unswept areas of the field, using a semi submersible drilling unit.
- Drilling of the Nadia exploration well was recently drilled and encountered a 90 foot sand interval containing hydrocarbons in the Brent formation. This well is currently suspended.
- During Q2/05, production from the Ninian South Platform will be suspended for three weeks in order to facilitate a scheduled maintenance shut-down. This will impact production levels from a portion of the Ninian Field as well as the Lyell Field and the Columbas Terraces.
- Commencing late in Q3/05, production from the Kyle Field will be diverted to the Banff FPSO. The existing Kyle FPSO will be released in September 2005. The consolidation of these production facilities will result in lower combined operating costs from these fields and will ultimately extend field lives for both fields.

Offshore West Africa

- The development of the 57.61% owned and operated Baobab Field, located offshore Côte d'Ivoire continued on time and on budget. The Baobab FPSO vessel was moored on location early in Q1/05 and is now being tied into the subsea facilities. The installation of subsea equipment and pipelines commenced during the quarter and is progressing for first production, expected mid 2005. Wells drilled, completed and tested to date continue to meet or exceed delivery expectations. Initial production rates of approximately 25 mbbl/d net to Canadian Natural are expected by mid year, subsequently increasing to approximately 35 mbbl/d in the first half of 2006.
- Net production at East Espoir continues to meet expectations, averaging 10 mboe/d during Q1/05. To facilitate the drilling of 4 additional (2.3 net) infill wells in East Espoir and modifications to the Espoir FPSO to accommodate West Espoir, production was shut in for two weeks during Q1/2005 resulting in approximately 2 mboe/d of curtailed production averaged over the quarter. The infill drilling program commenced during the quarter.
- The West Espoir drilling tower which will facilitate development drilling of this reservoir is also under construction, progressing on time and within budget. First oil from West Espoir is expected in mid 2006 delivering 13 mboe/d when fully commissioned.
- During Q1/2005 the 50% owned and operated Block 16 located offshore Angola was made available for sale with bids currently being evaluated. This decision was made since the prospects on the Block were outside the strict internal risk evaluation parameters maintained by the Company.

Horizon Oil Sands Project

- The Horizon Oil Sands Project ("Horizon Project") continues on plan and on budget. First production of 110 mbbl/d of light, sweet synthetic crude oil from Phase 1 construction is targeted to commence in the second half of 2008. Production is targeted to increase to 155 mbbl/d following completion of Phase 2 in 2010. Finally, production levels of 232 mbbl/d will be reached following completion of Phase 3 construction targeted for 2012.
- The Board of Directors unanimously authorized management to proceed with Phase 1 of the Horizon Project on February 9, 2005. This decision reflected the high degree of project definition that has enabled the Company to obtain approximately 68% of the $6.8 billion Phase 1 costs on a fixed price basis. To further mitigate the risks associated with fixed price bidding, the Phase 1 construction efforts were broken down into 21 individual projects, with cost estimates ranging from $10 million to $700 million.
- The high degree of up front project engineering and pre-planning also reduces the risks on "cost-plus" aspects of the project and will mitigate the risk of scope changes on the fixed bid portions. The pre-engineering and lessons learned from predecessors have also enabled the Company to prepare a detailed development and logistical plan to reduce the scheduling risk. Geological risk is low on the Company's mining leases as over 16 delineation wells have been drilled per section with over 40 wells per section having been drilled on the south pit, which will be the first to be mined. Finally, technology risk is low as the Company is using existing proven technologies for mining, extraction and upgrading processes.
- Total targeted capital costs for all three phases of the development are $10.8 billion. Capital costs for the first phase of the Horizon Project will be, including a contingency fund of $700 million, $6.8 billion with $1.4 billion incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion incurred in 2006, 2007 and 2008 respectively.
- As a result of the Board of Directors approval of the first phase of the Horizon Project, independent qualified reserve evaluators, Gilbert Laustsen Jung Associates Ltd., evaluated the leases associated with the Horizon Project and assigned 3.3 billion barrels of proved and probable bitumen mining reserves before royalties. These reserves were evaluated under SEC Industry Guide 7 and included in the Company's mining reserves effective February 9, 2005.

Project status summary	**March 31, 2005**		June 30, 2005
	Actual	Plan	Plan
Work progress (cumulative)	**2%**	2%	6%
Capital spending (cumulative)	**2%**	2%	7%

Accomplished during the first quarter

- All Engineer, Procure and Construct ("EPC") contractors for process plants have kicked off detailed engineering and mobilized their teams. Canadian Natural has located professional personnel into engineering contractors' offices in Alberta, California, Michigan and Italy to ensure quality, operability, integrity of design, and co-ordination of construction planning.
- Site clearing for the mine site is over 66% complete and on schedule.
- Site infrastructure such as temporary power and natural gas has been completed on schedule.
- Site grading and installation of deep underground facilities such as electrical, natural gas, water and sewage are approximately 10% complete overall and on schedule.
- Total site man-hours to date are approximately 850,000.
- There are 359 Canadian Natural employees on the Horizon Project, augmented by 531 contractors and 358 construction workers on site.
- Completed drilling program of 122 stratigraphic delineation wells on the Company's oil sands mining leases.

Q2/2005 milestones

- Turnover of the Coker foundations area to the contractor.
- Complete temporary water and sewage treatment plants.
- Complete site clearing.

MARKETING

	Q1/05	Q4/04	Q1/04
Crude oil and NGLs pricing			
Benchmark crude oil for WTI (US$/bbl)	**$ 49.90**	$ 48.27	$ 35.16
Lloyd Blend heavy oil differential from WTI	**39%**	41%	28%
US/Canada average exchange rate (US$)	**$ 0.8152**	$ 0.8195	$ 0.7587
Corporate average pricing before hedging activities (C$/bbl)	**$ 39.81**	$ 36.92	$ 34.21
Natural gas pricing			
Benchmark natural gas pricing for AECO (C$/GJ)	**$ 6.35**	$ 6.71	$ 6.26
Corporate average pricing before hedging activities (C$/mcf)	**$ 6.68**	$ 6.77	$ 6.31

- Crude oil and NGLs pricing benefited from higher WTI reference pricing and an improvement in heavy crude oil differentials. The long-term historical average for these differentials is approximately 30%. In late 2004, as a result of physical limitations for demand at refineries due to plant turnarounds and maintenance which exacerbated the impact of normal seasonality, differentials widened well beyond this level. Additionally, issues at refineries and upgraders, as well as the higher prices of diluents temporarily reduced the realizable value for bitumen.

FINANCIAL REVIEW

- Over the past several years, Canadian Natural has been preparing its financial position to not only profitably grow its conventional crude oil and natural gas operations over the next several years, but also to build the financial capacity to complete the Horizon Project. A brief summary of its strengths are:
  - A diverse asset base geographically and by product - currently producing in excess of 530 mboe/d, which is approximately 46% natural gas and 54% crude oil - with 98% of production located in G7 countries with stable and secure economies.
  - Financial stability and liquidity – a $1.5 billion bank credit facility for the Horizon Project with a 5-year term plus three, 1-year renewal options. In the aggregate, Canadian Natural had $2.6 billion of unused bank lines available at March 31, 2005.
  - Strong balance sheet – with a debt to book capitalization ratio of 37%, a debt to cash flow of 1.0x, a debt to EBITDA of 0.9x and shareholders' equity of $6.9 billion.
  - Financial flexibility – Canadian Natural's 5- and 10-year plans allow it to be proactive in its planning to allow for maximum flexibility as the Company moves forward to develop its conventional crude oil and natural gas asset base and the Horizon Project's mining assets.
- In order to ensure adequate free cash flow from conventional crude oil and natural gas operations to fund the Horizon Project, the Company's Board of Directors amended, in the first quarter of 2005, the Company's hedge policy. Under this revised policy, Management may hedge up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production, and up to 25% of production expected in months 25 through 48. Based on this amended policy, approximately 70% of expected 2005 and 50% of expected 2006 crude oil volumes have been hedged. Approximately 67% of expected 2005 and 40% of expected 2006 natural gas volumes have been similarly hedged through the use of collars. Details of current hedge positions may be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/hedging.html.
- As effective as economic hedges are against reference commodity prices, a certain portion of the hedges do not meet the requirements for hedge accounting under Generally Accepted Accounting Principles ("GAAP") due to currency, product quality and location differentials (the "non-designated hedges"). Hence, the Company is required to revalue the non-designated hedges to prevailing market prices at each quarter end. Due to the sharp increase in crude oil prices at the end of March 2005, Canadian Natural, recorded an after-tax expense of approximately $679 million on its risk management activities. This unrealized risk management expense essentially reflects, at March 31, 2005, the implied price differentials for the non-designated hedges for the next 7 quarters. This does not affect the Company's first quarter cash flows or its ability to finance its ongoing capital programs. Management believes its risk management program continues to meet the objective by securing funding for the Horizon Project and will not alter its current strategy of obtaining price certainty for its crude oil and natural gas production in order to underpin its capital expenditure programs during the Horizon Project construction years
- The Normal Course Issuer Bid has been extended to January 2006, allowing for the repurchase of up to 13.4 million shares through facilities of the Toronto Stock Exchange and the New York Stock Exchange. To date, no common shares have been repurchased under this program.
- In February 2005, Canadian Natural's Board of Directors approved an increase in the annual dividend to $0.45 per common share from the previous level of $0.40 per common share. The 12.5% increase recognizes the stability of Canadian Natural's cash flow and provides a further return to shareholders. This is the fifth consecutive year in which the Company has paid dividends and the fourth consecutive year of increase in the distribution paid to its shareholders.

OUTLOOK

The Company currently expects 2005 production levels before royalties to average 1,448 to 1,510 mmcf/d of natural gas and 307 to 335 mbbl/d of crude oil and NGLs. Q2/2005 production guidance before royalties is 1,478 to 1,521 mmcf/d of natural gas and 280 to 303 mbbl/d of crude oil and NGLs. Detailed guidance on production levels and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/. Commodity hedge information is regularly updated and may similarly be found at http://www.cnrl.com/investor_info/corporate_guidance/hedging.html.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of Canadian Natural Resources Limited (the "Company"), should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2005 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2004.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf: 1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise.

The following discussion refers primarily to the Company's first quarter 2005 financial results compared to the first quarter 2004 and the fourth quarter 2004. This MD&A is dated April 29, 2005.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004 [1]
Revenue, before royalties	**$ 1,993**	$ 1,969	$ 1,638
Net earnings (loss)	**$ (424)**	$ 577	$ 258
Per common share – basic	**$ (1.58)**	$ 2.15	$ 0.96
– diluted	**$ (1.58)**	$ 2.13	$ 0.96
Adjusted net earnings from operations[2]	**$ 380**	$ 321	$ 339
Per common share – basic	**$ 1.42**	$ 1.20	$ 1.27
– diluted	**$ 1.42**	$ 1.19	$ 1.26
Cash flow from operations[3]	**$ 1,009**	$ 950	$ 848
Per common share – basic	**$ 3.76**	$ 3.54	$ 3.16
– diluted	**$ 3.76**	$ 3.52	$ 3.14
Capital expenditures, net of dispositions	**$ 1,372**	$ 1,421	$ 1,493

(1) Restated to reflect two-for-one share split in May 2004.

(2) Adjusted net earnings from operations is a non-GAAP term that represents net earnings (loss) adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The following reconciliation lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results.

($ millions)	*Three months ended Mar 31 2005*	*Dec 31 2004*	*Mar 31 2004*
Net earnings (loss) as reported	***$ (424)***	*$ 577*	*$ 258*
Unrealized foreign exchange (gain) loss, net of tax [a]	***-***	*(61)*	*38*
Unrealized risk management loss (gain), net of tax [b]	***679***	*(212)*	*68*
Stock-based compensation expense, net of tax [c]	***125***	*17*	*41*
Effect of statutory tax rate changes on future income tax liabilities [d]	***-***	*-*	*(66)*
Adjusted net earnings from operations	***$ 380***	*$ 321*	*$ 339*

a) *Unrealized foreign exchange gains and losses result primarily from the translation of long-term debt to period end exchange rates and are immediately recognized in net earnings.*

b) *Effective January 1, 2004, the Company adopted a new accounting standard whereby financial instruments not designated as hedges are valued at fair value on its balance sheet, with changes in fair value, net of taxes, flowing through earnings. The realized value may be different than reflected in these financial statements due to changes in the underlying items hedged, primarily crude oil and natural gas prices.*

c) *The Company's employee stock option plan provides for a cash payment option. The fair value of the outstanding stock options is recorded as a liability on the Company's balance sheet and quarterly changes in the fair value, net of taxes, flow through net earnings.*

d) *All substantively enacted adjustments in applicable income tax rates are applied to underlying assets and liabilities on the Company's balance sheet in determining future income tax assets and liabilities. The impact of these tax rate changes is recorded in net earnings during the period the legislation is substantively enacted. During the first quarter of 2004, the province of Alberta introduced legislation to reduce its corporate income tax rate.*

(3) Cash flow from operations is a non-GAAP term that represents net earnings (loss) adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

	Three months ended		
($ millions)	**Mar 31 2005**	Dec 31 2004	Mar 31 2004
Net earnings (loss)	***$ (424)***	*$ 577*	*$ 258*
Non-cash items:			
Depletion, depreciation and amortization	***474***	*501*	*389*
Asset retirement obligation accretion	***18***	*16*	*11*
Stock-based compensation	***184***	*24*	*56*
Unrealized risk management activities loss (gain)	***998***	*(317)*	*102*
Unrealized foreign exchange (gain) loss	**-**	*(77)*	*47*
Deferred petroleum revenue tax (recovery)	**-**	*(32)*	*4*
Future income tax (recovery) expense	***(241)***	*258*	*(19)*
Cash flow from operations	***$ 1,009***	*$ 950*	*$ 848*

In the first quarter of 2005, the Company recorded a loss of $424 million as a result of its risk management activities and stock-based compensation plans, while adjusted net earnings from operations increased 12% to $380 million, up from $339 million in the comparable period in 2004, and increased 18% from $321 million in the prior quarter, due to strong commodity prices and record levels of natural gas production.

In January 2005, the Board of Directors of the Company authorized an expanded hedging program for the Company to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period. This expanded program allows for up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48 to be hedged. For the purpose of this program, the purchase of put options is in addition to the above parameters. As a result of the expanded hedging program, approximately 70% of expected 2005 and approximately 50% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 67% of expected 2005 natural gas volumes and approximately 40% of expected 2006 natural gas volumes have similarly been hedged through the use of collars. Details of the Company's risk management activities program can be found in note 10 to the consolidated financial statements.

As effective as economic hedges are against reference commodity prices, a certain portion of the financial instruments entered into by the Company do not meet the requirements for hedge accounting under Generally Accepted Accounting Principles ("GAAP") due to currency, product quality and location differentials (the "non-designated hedges"). As a result, the Company is required to mark-to-market the non-designated hedges based on the prevailing market prices. Due to the sharp increase in crude oil prices at the end of March 2005, the Company recorded a $998 million ($679 million after tax) unrealized loss on its risk management activities. The unrealized risk management expense primarily reflects, at March 31, 2005, the implied price differentials for the non-designated hedges for the remainder of 2005 and 2006. This does not affect the Company's first quarter cash flow or the Company's ability to finance ongoing capital programs. The Company believes the risk management program continues to meet the objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas production in order to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period.

The Company also recorded a $184 million ($125 million after tax) stock-based compensation expense in the first quarter of 2005 as a result of the 33% appreciation in the Company's share price (March 31, 2005 – C$68.36). The Company's stock options are fair valued at the end of each quarter based on the market price of the Company's common shares, with any changes recognized in net earnings. The stock-based compensation expense reflects the increase in the potential cash liability should all the options be exercised for a cash payout at the market price on March 31, 2005. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

Cash flow from operations for the three months ended March 31, 2005 increased 19% to $1,009 million from $848 million in the comparable period in 2004 and increased 6% from $950 million in the prior quarter due mainly to strong commodity prices and record levels of natural gas production.

Total production averaged 530,316 boe/d before royalties for the three months ended March 31, 2005, up 11% from 476,944 boe/d in the comparable period in 2004, but down slightly from 530,745 boe/d in the prior quarter.

OPERATING HIGHLIGHTS

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs ($/bbl, except daily production)			
Daily production, before royalties (bbl/d)	**287,803**	295,704	261,286
Sales price[1]	**$ 39.81**	$ 36.92	$ 34.21
Royalties	**3.39**	2.95	2.91
Production expense	**11.30**	10.41	9.58
Netback	**$ 25.12**	$ 23.56	$ 21.72
Natural gas ($/mcf, except daily production)			
Daily production, before royalties (mmcf/d)	**1,455**	1,410	1,294
Sales price[1]	**$ 6.68**	$ 6.77	$ 6.31
Royalties	**1.30**	1.34	1.27
Production expense	**0.69**	0.68	0.65
Netback	**$ 4.69**	$ 4.75	$ 4.39
Barrels of oil equivalent ($/boe, except daily production)			
Daily production, before royalties (boe/d)	**530,316**	530,745	476,944
Sales price[1]	**$ 39.94**	$ 38.51	$ 35.88
Royalties	**5.42**	5.21	5.03
Production expense	**8.04**	7.61	7.02
Netback	**$ 26.48**	$ 25.69	$ 23.83

(1) Including transportation costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
WTI benchmark price (US$/bbl)	**$ 49.90**	$ 48.27	$ 35.16
Dated Brent benchmark price (US$/bbl)	**$ 47.71**	$ 44.06	$ 31.98
Differential to LLB blend (US$/bbl)	**$ 19.26**	$ 19.61	$ 9.92
Condensate benchmark price (US$/bbl)	**$ 51.45**	$ 48.56	$ 35.99
NYMEX benchmark price (US$/mmbtu)	**$ 6.31**	$ 6.86	$ 5.69
AECO benchmark price (C$/GJ)	**$ 6.35**	$ 6.71	$ 6.26
US / Canadian dollar average exchange rate (US$)	**0.8152**	0.8195	0.7587

World crude oil prices remained strong in the first quarter of 2005 due to strong world-wide demand growth, particularly in the United States and Asia. West Texas Intermediate ("WTI") averaged US$49.90 per bbl for the three months ended March 31, 2005, up 42% compared to US$35.16 per bbl in the comparable period in 2004 and up 3% from US$48.27 per bbl in the prior quarter. The impact of the higher WTI prices on the Company's heavier crude oil production continues to be mitigated as a result of wider heavy crude oil differentials, which increased 94% to US$19.26 per bbl for the three months ended March 31, 2005 from the comparable period in 2004. The heavy crude oil differentials decreased 2% from US$19.61 per bbl in the prior quarter. The heavy crude oil differentials have reduced from the highs reached in late December 2004. However, the heavy crude oil differentials are higher than the long-term average as a result of physical limitations for demand at refineries and due to plant turnarounds and maintenance, which exacerbated the impact of normal seasonality. Additional problems at refineries and upgraders, as well as the higher prices of diluents required to reduce the viscosity of heavy crude oil production to meet requirements for transmission in sales pipelines, have contributed to lower heavy crude oil price realizations. Realized crude oil prices were also impacted by the stronger Canadian dollar.

North America natural gas prices remained strong due to concerns around supply and the impact of higher crude oil prices. NYMEX natural gas prices increased 11% to average US$6.31 per mmbtu for the three months ended March 31, 2005 from US$5.69 per mmbtu in the comparable period in 2004, but decreased 8% from US$6.86 per mmbtu in the prior quarter. AECO natural gas prices increased 1% to average $6.35 per GJ for the three months ended March 31, 2005, up from $6.26 per GJ in the comparable period in 2004, but decreased 5% from $6.71 per GJ in the prior quarter.

PRODUCT PRICES[1]

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs ($/bbl)			
North America	**$ 32.28**	$ 30.99	$ 30.72
North Sea	**$ 59.56**	$ 52.77	$ 44.27
Offshore West Africa	**$ 62.34**	$ 51.28	$ 42.08
Company average	**$ 39.81**	$ 36.92	$ 34.21
Natural gas ($/mcf)			
North America	**$ 6.73**	$ 6.88	$ 6.37
North Sea	**$ 3.52**	$ 3.26	$ 5.08
Offshore West Africa	**$ 7.67**	$ 4.73	$ 4.80
Company average	**$ 6.68**	$ 6.77	$ 6.31
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**54%**	53%	52%
Natural gas	**46%**	47%	48%

(1) Including transportation costs and excluding risk management activities.

Realized crude oil prices increased 16% to average $39.81 per bbl for the three months ended March 31, 2005, up from $34.21 per bbl in the comparable period in 2004, and increased 8% from $36.92 per bbl in the prior quarter. The increase in realized crude oil prices is a result of higher benchmark crude oil prices.

The Company's realized natural gas price increased 6% to average $6.68 per mcf for the three months ended March 31, 2005, up from $6.31 per mcf in the comparable period in 2004. The realized natural gas price decreased 1% from $6.77 per mcf in the prior quarter.

North America

North America realized crude oil prices increased 5% to average $32.28 per bbl for the three months ended March 31, 2005, up from $30.72 per bbl in the comparable period in 2004, and increased 4% from $30.99 per bbl in the prior quarter. The increase in the realized crude oil price is due mainly to higher world crude oil prices, partially mitigated by wider heavy crude oil differentials and the stronger Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, which includes the development of a blending strategy, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with PADD II refiners to add incremental heavy crude oil conversion capacity. As part of an industry initiative to develop new blends of Western Canadian crude oils, the Company has access to blending capacity of up to 140 mbbl/d. The Company is contributing 125 mbbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy oil with premium quality asphalt characteristics. The new blend has an API of 19-22 degrees and is expected to grow, with the potential to become a new benchmark for North American markets in addition to WTI. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian west coast where crude cargos can be sold on a world-wide basis. The Company has committed to 25,000 bbl/d of capacity on the Corsicana Pipeline, which will carry crude oil to the Gulf of Mexico and is expected to be in operation later this year. The Corsicana Pipeline is made up of a series of segments extending from Patoka Illinois to Beaumont Texas, near the Gulf Coast.

North America realized natural gas prices increased 6% to average $6.73 per mcf for the three months ended March 31, 2005, up from $6.37 per mcf in the comparable period in 2004. The realized natural gas price decreased 2% from $6.88 per mcf in the prior quarter due to fluctuations in the North America benchmark natural gas price.

A comparison of the price received for the Company's North American production is as follows:

	Q1 2005	Q4 2004	Q1 2004
Wellhead price[1]			
Light crude oil and NGLs (C$/bbl)	**$ 50.46**	$ 49.34	$ 40.69
Pelican Lake crude oil (C$/bbl)	**$ 31.74**	$ 29.90	$ 29.93
Primary heavy crude oil (C$/bbl)	**$ 25.46**	$ 24.96	$ 27.17
Thermal heavy crude oil (C$/bbl)	**$ 24.69**	$ 25.52	$ 26.57
Natural gas (C$/mcf)	**$ 6.73**	$ 6.88	$ 6.37

(1) Including transportation costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 35% to average $59.56 per bbl for the three months ended March 31, 2005, up from $44.27 per bbl in the comparable period in 2004, and increased 13% from $52.77 per bbl in the prior quarter. The increase in the realized crude oil price is due mainly to higher world crude oil prices and fluctuations in the Brent differential.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 48% to average $62.34 per bbl for the three months ended March 31, 2005, up from $42.08 per bbl in the comparable period in 2004, and increased 22% from $51.28 per bbl in the prior quarter. The increase in the realized crude oil price is due to higher world crude oil prices.

DAILY PRODUCTION, before royalties

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs (bbl/d)			
North America	**209,125**	214,493	192,151
North Sea	**71,139**	69,971	57,099
Offshore West Africa	**7,539**	11,240	12,036
	287,803	295,704	261,286
Natural gas (mmcf/d)			
North America	**1,430**	1,365	1,230
North Sea	**23**	40	54
Offshore West Africa	**2**	5	10
	1,455	1,410	1,294
Total barrel of oil equivalent (boe/d)	**530,316**	530,745	476,944
Product mix			
Light crude oil and NGLs	**25%**	24%	25%
Pelican Lake crude oil	**3%**	4%	4%
Primary heavy crude oil	**17%**	18%	19%
Thermal heavy crude oil	**9%**	10%	7%
Natural gas	**46%**	44%	45%

DAILY PRODUCTION, net of royalties

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs (bbl/d)			
North America	**179,472**	187,106	168,052
North Sea	**71,074**	69,863	57,020
Offshore West Africa	**7,310**	10,908	11,670
	257,856	267,877	236,742
Natural gas (mmcf/d)			
North America	**1,148**	1,092	973
North Sea	**23**	40	54
Offshore West Africa	**2**	5	9
	1,173	1,137	1,036
Total barrel of oil equivalent (boe/d)	**453,385**	457,356	409,493

Daily production and per barrel statistics are presented throughout the MD&A on a “before royalty” or “gross” basis. Production net of royalties is presented above for information purposes only.

The Company’s business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

Production before royalties on a barrel of crude oil equivalent basis was 530,316 boe/d for the three months ended March 31, 2005, up 11% or 53,372 boe/d from the comparable period in 2004. The increase in production was due to the Company’s extensive capital expenditure program resulting in record levels of natural gas production and accretive acquisitions completed in 2004.

Total crude oil and NGLs production before royalties increased 10% or 26,517 bbl/d to average 287,803 bbl/d for the three months ended March 31, 2005, up from 261,286 bbl/d for the comparable period in 2004, but decreased 3% or 7,901 bbl/d from the prior quarter. Crude oil and NGLs production before royalties in the first quarter of 2005 was in line with the Company’s guidance of 269,000 to 290,000 bbl/d.

Natural gas production before royalties continues to represent the Company’s largest product offering. Natural gas production before royalties for the three months ended March 31, 2005 increased 12% or 161 mmcf/d from the comparable period in 2004 to average 1,455 mmcf/d, and increased 3% or 45 mmcf/d from the prior quarter. The increase was a result of a successful natural gas drilling program and the acquisition of certain resource properties during 2004 in the Company’s North America segment. Natural gas production before royalties in the first quarter of 2005 was in line with the Company’s guidance of 1,440 to 1,482 mmcf/d.

The Company expects annual production levels before royalties in 2005 to average 1,448 to 1,510 mmcf/d of natural gas and 307 to 335 mbbl/d of crude oil and NGLs. Second quarter 2005 production guidance before royalties is 1,478 to 1,521 mmcf/d of natural gas and 280 to 303 mbbl/d of crude oil and NGLs.

North America

Crude oil and NGLs production before royalties in North America for the three months ended March 31, 2005 increased 9% or 16,974 bbl/d to average 209,125 bbl/d, up from 192,151 bbl/d in the comparable period in 2004, but decreased 3% or 5,368 bbl/d from 214,493 bbl/d in the prior quarter due mainly to the timing of Primrose production cycles.

North America natural gas production before royalties for the three months ended March 31, 2005 increased 16% or 200 mmcf/d to average 1,430 mmcf/d, up from 1,230 mmcf/d in the comparable period in 2004, and increased 5% or 65 mmcf/d from 1,365 mmcf/d in the prior quarter. North American production of natural gas increased as a result of organic growth and accretive property acquisitions.

North Sea

Crude oil production before royalties from the North Sea for the three months ended March 31, 2005 increased 25% or 14,040 bbl/d to average 71,139 bbl/d, up from 57,099 bbl/d in the comparable period in 2004, and increased 2% or 1,168 bbl/d from 69,971 bbl/d in the prior quarter. Crude oil production before royalties was impacted by the unplanned extended shutdown on the Ninian North Platform due to the loss of pressure to the reservoir as a result of problems with a power turbine used to drive water injection. Remedial work is completed and production is recovering.

In the second quarter of 2005, production from the Ninian South Platform will be shutdown for three weeks in order to complete scheduled maintenance. The shutdown will impact production levels from part of the Ninian Field as well as the Lyell Field and Columbas Terraces.

Natural gas production before royalties in the North Sea for the three months ended March 31, 2005 decreased 57% or 31 mmcf/d to average 23 mmcf/d, down from 54 mmcf/d in the comparable period in 2004 and decreased 43% or 17 mmcf/d from 40 mmcf/d in the prior quarter. The decrease was due to the commencement of the natural gas reinjection program in the Banff Field in the Central North Sea in the fourth quarter of 2004. The natural gas reinjection project is expected to result in an overall increase in the reservoir recovery, but will result in reductions in natural gas production. Despite some delays and production interruptions during commissioning, results to date are positive with full production benefit expected to commence during the second quarter of 2005.

Offshore West Africa

Offshore West Africa crude oil production before royalties for the three months ended March 31, 2005 decreased 37% or 4,497 bbl/d to average 7,539 bbl/d, down from 12,036 bbl/d in the comparable period in 2004, and decreased 33% or 3,701 bbl/d from 11,240 bbl/d in the prior quarter due to the curtailment of production. Production was curtailed to facilitate the drilling of four additional (2.3 net) infill wells in East Espoir and in order to make modifications to the Floating Production Storage and Offtake vessel ("FPSO") to accommodate West Espoir production. The infill drilling commenced during the first quarter.

Natural gas production before royalties in Offshore West Africa for the three months ended March 31, 2005 decreased 80% or 8 mmcf/d, to average 2 mmcf/d from 10 mmcf/d the comparable period in 2004 and decreased 60% or 3 mmcf/d from 5 mmcf/d in the prior quarter. The decrease in natural gas production was due to the shut-in of production noted above.

Production was shut-in for approximately 2 weeks in the first quarter to accommodate the drilling and modifications to the FPSO, resulting in approximately 2 mboe/d of production being curtailed.

ROYALTIES

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs ($/bbl)			
North America	**$ 4.58**	$ 3.96	$ 3.85
North Sea	**$ 0.05**	$ 0.08	$ 0.06
Offshore West Africa	**$ 1.90**	$ 1.52	$ 1.28
Company average	**$ 3.39**	$ 2.95	$ 2.91
Natural gas ($/mcf)			
North America	**$ 1.33**	$ 1.39	$ 1.33
North Sea	**$ -**	$ -	$ -
Offshore West Africa	**$ 0.23**	$ 0.14	$ 0.15
Company average	**$ 1.30**	$ 1.34	$ 1.27
Company average ($/boe)	**$ 5.42**	$ 5.21	$ 5.03
Percentage of revenue(1)			
Crude oil and NGLs	**9%**	8%	8%
Natural gas	**20%**	20%	20%
Boe	**14%**	14%	14%

(1) Including transportation costs and excluding risk management activities.

North America

North America crude oil and NGLs royalties increased from both the comparable period in 2004 and the prior quarter due to higher benchmark crude oil prices.

Natural gas royalties as a percentage of revenue fluctuated from the prior quarter as a result of fluctuations in natural gas prices and the strong correlation of royalties to natural gas prices.

North Sea

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The only remaining royalty in the North Sea is a gross overriding royalty on the Ninian Field.

Offshore West Africa

Offshore West Africa production is governed by the terms of the Production Sharing Contract (“PSC”). Under the PSC, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover the capital and operating costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government’s share of revenue attributable to the Company’s equity interest is reported as either royalty expense or current income tax expense in accordance with the PSC.

PRODUCTION EXPENSE

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs ($/bbl)			
North America	**$ 10.07**	$ 9.06	$ 8.65
North Sea	**$ 14.91**	$ 14.96	$ 13.26
Offshore West Africa	**$ 11.43**	$ 7.82	$ 7.09
Company average	**$ 11.30**	$ 10.41	$ 9.58
Natural gas ($/mcf)			
North America	**$ 0.66**	$ 0.63	$ 0.60
North Sea	**$ 2.52**	$ 2.29	$ 1.65
Offshore West Africa	**$ 1.25**	$ 1.31	$ 1.23
Company average	**$ 0.69**	$ 0.68	$ 0.65
Company average ($/boe)	**$ 8.04**	$ 7.61	$ 7.02

North America

North America crude oil and NGLs production expense for the three months ended March 31, 2005 increased from the comparable period in 2004 due to thermal crude oil production making up a larger portion of the Company's crude oil and NGLs production, increased service costs as a result of increased activity in reaction to higher commodity prices, and the impact of the higher WTI price on gasoline and other production expenses. North America crude oil and NGLs production expense increased from the prior quarter as a result of higher costs experienced in winter months and the increase in chemicals purchased and maintenance done in the first quarter.

North America natural gas production expense per mcf for the three months ended March 31, 2005 increased from the comparable period in 2004. The increase is due to the cost pressures noted above.

North Sea

North Sea crude oil production expense varied on a per barrel basis from both the comparable period in 2004 and the prior quarter due to the timing of maintenance work and the changes in production volumes on a relatively fixed cost base.

Offshore West Africa

Offshore West Africa crude oil production expenses are largely fixed in nature and therefore fluctuate on a per barrel basis from the comparable periods due to changes in production from the Espoir Field.

MIDSTREAM

($ millions)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Revenue	**$ 21**	$ 18	$ 16
Production expense	**6**	5	4
Midstream cash flow	**15**	13	12
Depreciation	**2**	2	2
Segment earnings before taxes	**$ 13**	$ 11	$ 10

The Company'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 80% of the Company's heavy crude oil production was transported to the international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy crude oil.

Revenue from the midstream assets for the three months ended March 31, 2005 increased from the comparable period in 2004 and the prior quarter due to increased third party revenue earned from the Pelican Lake Pipeline.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Expense ($ millions)	**$ 472**	$ 499	$ 387
$/boe	**$ 9.89**	$ 10.24	$ 8.91

(1) DD&A excludes depreciation on midstream assets.

Depletion, Depreciation and Amortization ("DD&A") for the three months ended March 31, 2005 increased in total and per boe from the comparable period in 2004. The increase in DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with recent acquisitions, future abandonment costs associated with the acquisition of additional properties in the North Sea, and higher costs to develop the Company's proved undeveloped reserves. DD&A decreased in total and per boe from the prior quarter due to the results of the first quarter capital expenditures program.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Expense ($ millions)	**$ 18**	$ 16	$ 11
$/boe	**$ 0.38**	$ 0.33	$ 0.25

Asset retirement obligation accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time.

ADMINISTRATION EXPENSE

	Three months ended		
	Mar 31 2005	Dec 31 2004[(1)]	Mar 31 2004[(1)]
Expense ($ millions)	**$ 35**	$ 36	$ 28
$/boe	**$ 0.74**	$ 0.72	$ 0.65

(1) Restated to conform to current year presentation.

Administration expense for the three months ended March 31, 2005 increased in total and on a per boe basis from the comparable period in 2004 due to higher staffing levels associated with the Company's expanding asset base.

Included in administration expense is the cost associated with the Company's Share Bonus Plan. The Share Bonus Plan incorporates share ownership in the Company by its employees without the granting of stock options or the dilution of current Shareholders. Under the plan, a cash bonus may be awarded based on the Company's and the employee's performance and subsequently used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. For the three months ended March 31, 2005, the Company has recognized $7 million of compensation expense under the Share Bonus Plan (December 31, 2004 - $2 million, March 31, 2004 - $5 million).

STOCK-BASED COMPENSATION

	Three months ended		
	Mar 31 2005	Dec 31 2004[(1)]	Mar 31 2004[(1)]
Stock option plan ($ millions)	**$ 184**	$ 24	$ 56
$/boe	**$ 3.85**	$ 0.50	$ 1.30

(1) Restated to conform to current year presentation.

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The Option Plan balances the need for a long-term compensation program to retain employees with reducing the impact of dilution on current Shareholders and the reporting of the expense associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the fair value of outstanding stock options are expensed. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company has recorded a liability at March 31, 2005 of $446 million (December 31, 2004 - $323 million; March 31, 2004 - $171 million) for expected cash settlements of stock options based on the fair value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of the Company's common shares). The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings for the quarter.

The stock-based compensation expense relating to the Company's Option Plan for the three months ended March 31, 2005 is $184 million ($125 million after tax) as a result of the 33% appreciation of the Company's share price to $68.36 in the quarter.

For the three months ended March 31, 2005, the Company paid $77 million for stock options surrendered for cash settlement (December 31, 2004 - $14 million; March 31, 2004 - $31 million).

INTEREST EXPENSE

	Three months ended		
	Mar 31 2005	Dec 31 2004	Mar 31 2004
Interest expense, net ($ millions)	**$ 43**	$ 48	$ 45
$/boe	**$ 0.91**	$ 1.00	$ 1.03
Average effective interest rate	**5.5%**	5.1%	5.7%

Interest expense decreased on a total and per boe basis for the three months ended March 31, 2005 from the comparable period in 2004 and prior quarter due to the capitalization of $11 million of interest related to the Horizon Project. Pre-capitalization interest increased over prior periods mainly due to higher overall debt levels. Pre-capitalization interest rates also increased over the prior quarter due to higher average effective interest rates. The average effective interest rate increased from the prior quarter due to an increase in short-term borrowing rates.

RISK MANAGEMENT ACTIVITIES

On January 1, 2004, the Company prospectively adopted the Canadian Institute of Charted Accountants' ("CICA") Accounting Guideline 13, "Hedging Relationships" and Emerging Issues Committee ("EIC") 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Financial instruments that do not qualify as hedges under the Guideline or are not designated as hedges ("non-designated hedges") are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on non-designated interest rate contracts are included in risk management activities.

The Company enters into cross currency swap agreements to manage its currency exposure on long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under other assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction is recognized. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Adoption of this Guideline and EIC 128 had the following effects on the Company's consolidated financial statements:

RISK MANAGEMENT

($ millions)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Realized loss (gain)			
Crude oil and NGLs financial instruments	**$ 105**	$ 180	$ 37
Natural gas financial instruments	**(10)**	2	-
Interest rate swaps	**(8)**	(7)	(9)
	$ 87	$ 175	$ 28
Unrealized loss (gain)			
Crude oil and NGLs financial instruments	**$ 907**	$ (321)	$ 106
Natural gas financial instruments	**86**	-	3
Interest rate swaps	**5**	4	(7)
	$ 998	$ (317)	$ 102
Total	**$ 1,085**	$ (142)	$ 130

The effect of the realized loss (gain) from crude oil and NGLs and natural gas financial instruments was to decrease (increase) the Company's average realized prices as follows:

	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Crude oil and NGLs ($/bbl)	**$ 4.07**	$ 6.63	$ 1.55
Natural gas ($/mcf)	**$ (0.08)**	$ -	$ -

The effect of the realized gain on interest rate swaps on the Company's interest expense was:

($ millions, except interest rates)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Interest expense as per the financial statements	**$ 43**	$ 48	$ 45
Less: realized risk management gain	**(8)**	(7)	(9)
	$ 35	$ 41	$ 36
Average effective interest rate	**4.5%**	4.6%	4.5%

FOREIGN EXCHANGE

($ millions)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Realized foreign exchange (gain) loss	**$ (12)**	$ 16	$ (4)
Unrealized foreign exchange (gain) loss	**-**	(77)	47
	$ (12)	$ (61)	$ 43

The majority of the realized foreign exchange gain or loss is a result of the effects of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling.

The majority of the unrealized foreign exchange gain or loss is related to the fluctuation in the Canadian dollar in relation to the US dollar. The Canadian dollar ended the first quarter of 2005 at US$0.8267 compared to US$0.8308 at December 31, 2004 (March 31, 2004 – US$0.7631).

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has 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 income tax rates)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Taxes other than income tax			
Current	**$ 42**	$ 47	$ 35
Deferred	**-**	(32)	4
Total	**$ 42**	$ 15	$ 39
Current income tax			
North America – Current income tax	**$ 30**	$ 1	$ 37
North America – Large corporations tax	**2**	5	3
North Sea	**39**	(16)	23
Offshore West Africa	**3**	3	3
Other	**-**	1	-
Total	**$ 74**	$ (6)	$ 66
Future income tax (recovery) expense	**$ (241)**	$ 258	$ (19)
Effective income tax rate	**28.3%**	30.4%	15.5%

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") 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 taxes increased from the comparable periods as a result of higher crude oil prices and increased production levels.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the amount of capital expenditures incurred in Canada and the way it is deployed.

The Company is liable for the payment of Federal Large Corporations Tax ("LCT"). LCT for the three months ended March 31, 2005 decreased to $2 million from $3 million in the comparable period in 2004 and $5 million in the prior quarter as a result of the Company being taxable and paying Federal corporate surtax. In addition, the LCT rate was reduced from 0.2% to 0.175% as part of the phased elimination of LCT over five years.

The North Sea current income tax expense for the three months ended March 31, 2005 increased to $39 million from $23 million in the comparable period in 2004 due mainly to higher realized product prices and increased production volumes. In the fourth quarter of 2004, the North Sea recorded a recovery of current income tax expense due to the tax pools acquired in a recent acquisition being immediately deductible.

In the first quarter of 2004, the North America future tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate from 12.5% to 11.5%. The Federal Government also introduced legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid.

The following table shows the effect of non-recurring benefits on income taxes:

	Three months ended		
($ millions, except income tax rates)	**Mar 31 2005**	Dec 31 2004	Mar 31 2004
Income tax as reported			
Current income tax expense (recovery)	**$ 74**	$ (6)	$ 66
Future income tax (recovery) expense	**(241)**	258	(19)
	(167)	252	47
Alberta corporate tax rate reduction	**-**	-	66
Total	**$ (167)**	$ 252	$ 113
Expected effective income tax rate	**28.3%**	30.4%	37.1%

CAPITAL EXPENDITURES

($ millions)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Expenditures on property, plant and equipment			
Net property acquisitions [1]	**$ 2**	$ 761	$ 507
Land acquisition and retention	**36**	13	31
Seismic evaluations	**41**	21	32
Well drilling, completion and equipping	**634**	359	583
Pipeline and production facilities	**432**	185	280
Total net reserve replacement expenditures	**1,145**	1,339	1,433
Horizon Oil Sands Project	**215**	58	46
Midstream	**4**	11	-
Abandonments	**4**	5	7
Head office	**4**	8	7
Total net capital expenditures	**$ 1,372**	$ 1,421	$ 1,493
By segment			
North America	**$ 940**	$ 1,141	$ 1,297
North Sea	**57**	87	76
Offshore West Africa	**144**	110	60
Other	**4**	1	-
Horizon Oil Sands Project	**215**	58	46
Midstream	**4**	11	-
Abandonments	**4**	5	7
Head office	**4**	8	7
Total	**$ 1,372**	$ 1,421	$ 1,493

(1) Includes Business Combinations.

The Company's strategy is focused on building a diversified asset base that is balanced between various products.

Capital expenditures in the first quarter of 2005 were $1,372 million compared to $1,493 million in the comparable period in 2004 and $1,421 million in the fourth quarter of 2004. The decrease in capital expenditures was a result of the decrease in property acquisitions. The Company continues to make significant progress on its larger, future-growth projects while maintaining its focus on existing assets. The Company drilled a total of 691 net wells consisting of 338 natural gas wells, 109 crude oil wells, 188 stratigraphic test and service wells, and 56 wells that were dry compared to 839 net wells in first quarter of 2004. The Company achieved an overall success rate of 89%, excluding stratigraphic test and service wells. These excellent results reflect the disciplined approach that the Company takes in its exploitation and development programs and the strength of its asset base.

North America

North America accounted for approximately 85% of the total capital expenditures in the first quarter of 2005 compared to approximately 90% in the comparable period in 2004.

During the first quarter, the Company drilled 386 net wells targeting natural gas, including 186 wells in Northeast British Columbia, 109 wells in the Northern Plains region, 71 wells in Northwest Alberta, and 20 wells in the Southern Plains region. The Company also drilled 114 net wells targeting crude oil during the first quarter 2005. These wells were concentrated in the Company's crude oil Northern Plains region where 61 heavy crude oil wells, 15 Pelican Lake crude oil wells, 16 thermal crude oil wells, and four light crude oil wells were drilled.

The Company increased capital spending levels directed toward natural gas drilling and in an effort to reduce pressures of a tight 2005 winter drilling season, started earlier. This effort included a detailed and sequential drilling program that facilitated the procurement of better drilling rigs and crews for the winter season; both of which are an integral part of cost control.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal project, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. The Primrose North expansion continues to be on track and on budget with total capital expenditures of approximately $300 million expected to be incurred, leading to first oil of 30 mbbl/d in 2006.

In the third quarter of 2004, the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometres from its existing Primrose South steam plant and 25 kilometres from its Wolf Lake central processing facility. Once completed, Primrose East will be fully integrated with existing operations at Wolf Lake, Primrose South and Primrose North. The Company currently expects to complete its regulatory application by late 2005 with a regulatory decision expected in late 2006.

The Pelican Lake enhanced crude oil recovery project continues on track. To date, the waterflood has provided initial production increases as expected and has shown positive waterflood response. The waterflood project will be expanded in 2005 and the Company plans to enhance the process by use of a polymer flood. Facilities for the Pelican Lake polymer flood have been installed in April and the pilot test has been initiated.

Horizon Oil Sands Project

On February 9, 2005 the Board of Directors of the Company unanimously authorized the Company to proceed with Phase 1 of the Horizon Project. This decision reflected the high degree of project definition that has enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. To further mitigate the risks associated with fixed price bidding, the Phase 1 construction efforts were broken down into 21 individual projects, each with a value ranging from $10 million to $700 million.

The Horizon Project continues on schedule and on budget. First production of 110 mbbl/d of light, sweet synthetic crude oil from Phase 1 construction is targeted to commence in the second half of 2008. Production levels of 232 mbbl/d will be reached following completion of the third phase of construction in 2012.

During the first quarter of 2005, all fixed priced Engineer, Procure and Construct ("EPC") contractors for process plants started detailed engineering and mobilization of their teams. It is expected that detailed engineering on the overall project will be approximately 80% complete by the end of 2005, at which time major construction will commence.

The Company has located professional personnel into engineering contractors' offices in Alberta, California, Michigan and Italy to ensure quality, operability, integrity of design and the co-ordination of construction planning. During the first quarter, site clearing for the mine site is over 66% complete and on schedule, site infrastructure such as temporary power and natural gas has been completed on schedule, site grading and installation of deep underground facilities, such as electrical, natural gas, water and sewage are approximately 10% complete and on schedule and 122 stratigraphic delineation wells were drilled.

In the second quarter of 2005, the temporary water and sewage treatment plants, the site clearing, and the muskeg removal in preparation for overburden removal, will be completed. Also, it is expected that the Coker foundations area will be turned over to the contractor.

North Sea

In the first quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the first quarter two wells were completed.

In anticipation of the 2005 program of infill drilling, workovers and third party business on the T and B Block, the Tiffany platform drilling rig is under going major refurbishment, which will facilitate a two well program. In the Thelma Field, two wells are scheduled to spud later this year targeting unswept areas of the field, using a semi submersible drilling unit. In addition, at Balmoral Field the Company has acquired exploration acreage in the vicinity of the Balmoral Floating Production Vessel.

In the fourth quarter of 2005, production from the Kyle Field will be diverted to the Banff FPSO. Under the terms of an early termination agreement, the existing Kyle FPSO will be released in September, 2005. The consolidation of these production facilities will result in lower combined operating costs from these fields and will ultimately extend field lives for both fields.

Offshore West Africa

Offshore West Africa capital expenditures include the development of the Baobab Field where drilling is ongoing. To date, production testing on four producer wells has met or exceeded expectations. In addition, the FPSO has been completed, is moored on location and has been tied into subsea facilities. The installation of subsea equipment and pipelines commenced during the quarter and is progressing for first production, expected mid 2005.

At East Espoir, an additional four (2.3 net) wells are scheduled for drilling in early 2005 as a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources from the field. A drilling tower is also under construction, progressing on time and within budget, and will be installed at West Espoir in order to facilitate development drilling. First oil from West Espoir is expected in mid 2006, delivering 13 mboe/d when fully commissioned.

Finally, even though additional review of seismic and geological data on Block 16 located offshore Angola indicates significant upside remains a possibility, its risk level is outside the normal operating parameters of the Company. As a result, the Company continues to evaluate alternatives for its holdings in the Block. During first quarter of 2005 a data room was opened and bids received are currently being evaluated.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Working capital deficit[1]	**$ 1,288**	$ 652	$ 923
Long-term debt	**$ 3,831**	$ 3,538	$ 3,165
Shareholders' equity			
Share capital	**$ 2,416**	$ 2,408	$ 2,380
Retained earnings	**4,468**	4,922	3,881
Foreign currency translation adjustment	**(6)**	(6)	1
Total	**$ 6,878**	$ 7,324	$ 6,262
Debt to cash flow[1][2]	**1.0x**	1.0x	1.0x
Debt to EBITDA[1][2]	**0.9x**	0.9x	0.9x
Debt to book capitalization[1]	**36.9%**	33.8%	34.1%
Debt to market capitalization[1]	**18.0%**	21.4%	24.9%
After tax return on average common shareholders' equity[2]	**10.7%**	21.4%	21.3%
After tax return on average capital employed[1][2]	**8.1%**	15.3%	14.9%

(1) Includes current portion of long-term debt.

(2) Based on trailing 12-month activity.

At March 31, 2005, the working capital deficit amounted to $1,288 million and includes the current portion of other long-term liabilities of $915 million, consisting of stock based compensation of $331 million and the mark to market valuation of certain Risk Management financial derivative instruments of $584 million. The settlement of the stock-based compensation liability is dependant upon the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The settlement of the Risk Management financial derivative instruments is primarily dependant upon the underlying crude oil and natural gas prices at the time of settlement of the financial derivative instrument, as compared to the value at March 31, 2005.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Project. In the first quarter of 2005, strong operational results and strong commodity prices resulted in debt to book capitalization levels of 36.9%. The Company has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of exceptional low-risk conventional crude oil and natural gas growth opportunities. The financing of the first phase of the Horizon Project development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to March 31, 2005, such as Baobab, Primrose and West Espoir provide identified growth in production volumes in 2005 and 2006, and will generate incremental free cash flows during the period 2005 to 2008.

In January 2005, the Board of Directors of the Company authorized an expanded hedging program for the Company to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period. This expanded program allows for up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48 to be hedged. For the purpose of this program, the purchase of put options is in addition to the above parameters. As a result of the expanded hedging program, approximately 70% of expected 2005 and approximately 50% of expected 2006 crude oil volumes have been hedged mainly through the use of collars. In addition, approximately 67% of expected 2005 and approximately 40% of expected 2006 natural gas volumes have similarly been hedged through the use of collars. Details of the Company's risk management activities program can be found in note 10 to the consolidated financial statements and is discussed in the risk management activities in the MD&A.

Long-term debt

At March 31, 2005, the Company had undrawn bank lines of credit of $2,572 million.

Share capital

As at March 31, 2005, there were 268,310,000 common shares outstanding. As at April 29, 2005, the Company has 268,326,000 common shares outstanding.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 13,409,006 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As of April 29, 2005, the Company had not purchased any common shares under the renewed Normal Course Issuer Bid.

In February 2005, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.45 per common share for 2005. The 12.5% increase recognizes the stability of the Company's cash flow and provides a return to Shareholders. This is the fifth consecutive year in which the Company has paid dividends and the fourth consecutive year of an increase in the distribution paid to its Shareholders. In February 2004, the Company's Board of Directors increased the annual dividend paid by the Company to $0.40 per common share in 2004, up from the previous level of $0.30 per common share.

In order to increase the liquidity of the Company's common shares, the Board of Directors has recommended to the Company's shareholders to subdivide the Company's common shares on a 2 for 1 basis, which will result in an increase in the Company's total outstanding common shares to approximately 536,652,000 common shares. This recommendation will be voted on by the shareholders at the Annual and Special Meeting of Shareholders to be held on May 5, 2005.

Contractual obligations

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments relate primarily to debt repayments, operating leases relating to office space and offshore production and storage vessels, firm commitments for gathering, processing and transmission services. The following table summarizes the Company's commitments as at March 31, 2005:

	2005	2006	2007	2008	2009	Thereafter
Natural gas transportation	$ 150	$ 166	$ 103	$ 79	$ 38	$ 167
Oil transportation and pipeline	$ 8	$ 9	$ 11	$ 12	$ 13	$ 154
FPSO operating lease	$ 66	$ 48	$ 48	$ 48	$ 48	$ 185
Baobab Project	$ 52	$ -	$ -	$ -	$ -	$ -
Offshore drilling and other	$ 130	$ 6	$ -	$ -	$ -	$ -
Electricity	$ 27	$ 39	$ 41	$ -	$ -	$ -
Office lease	$ 15	$ 21	$ 22	$ 23	$ 24	$ 30
Processing	$ 4	$ 2	$ -	$ -	$ -	$ -
Long-term debt	$ 194	$ -	$ 163	$ 38	$ 70	$ 2,725

Total capital costs for the three phases of the Horizon Project development are expected to be approximately $10.8 billion. The Board of Directors has approved the capital costs for the first phase of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion incurred in 2006, 2007 and 2008 respectively.

Subsequent event

On April 20, 2005, the Company announced the disposition of a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario for proceeds of approximately $345 million, after giving effect to anticipated adjustments. The transaction is expected to close on or about May 10, 2005 subject to the receipt of required regulatory approvals and standard closing conditions. Net proceeds received upon closing will be applied to reduce bank credit facilities.

Critical accounting estimates

The preparation of financial statements requires Management to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2004.

Capitalized interest

The Company capitalizes interest on major development projects during the construction period based on costs incurred and the Company's cost of borrowing. Interest capitalization ceases once construction is substantially complete.

For the three months ended March 31, 2005, the Company has capitalized interest in the amount of $11 million related to the construction of the Horizon Project.

SENSITIVITY ANALYSIS [1]

The following table is indicative of the annualized sensitivities of cash flow and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the first quarter of 2005. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl[2]				
Excluding financial derivatives	$ 91	$ 0.34	$ 63	$ 0.23
Including financial derivatives	$ 56 – 70	$ 0.21 – 0.26	$ 29 – 35	$ 0.11 – 0.13
Natural gas – AECO C$0.10/mcf[2]				
Excluding financial derivatives	$ 39	$ 0.15	$ 25	$ 0.09
Including financial derivatives	$ 39	$ 0.15	$ 25	$ 0.09
Volume changes				
Crude oil – 10,000 bbl/d	$ 76	$ 0.28	$ 38	$ 0.14
Natural gas – 10 mmcf/d	$ 17	$ 0.06	$ 7	$ 0.03
Foreign currency rate change				
$0.01 change in C$ in relation to US$[2]				
Excluding financial derivatives	$ 61 – 63	$ 0.23	$ 20 – 21	$ 0.07 – 0.08
Including financial derivatives	$ 61 – 63	$ 0.23	$ 20 – 21	$ 0.07 – 0.08
Interest rate change - 1%	$ 12	$ 0.04	$ 12	$ 0.04

(1) The sensitivities are calculated based on 2005 first quarter results excluding mark-to-market on risk management activities.

(2) For details of financial instruments in place, see the consolidated financial statement note 10.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe, except daily production)	Three months ended Mar 31 2005	Dec 31 2004	Mar 31 2004
Daily production, before royalties (boe/d)	**530,316**	530,745	476,944
Sales price[1]	**$ 39.94**	$ 38.51	$ 35.88
Royalties	**5.42**	5.21	5.03
Production expense[2]	**8.04**	7.61	7.02
Netback	**26.48**	25.69	23.83
Midstream contribution[2]	**(0.31)**	(0.27)	(0.27)
Administration[3]	**0.74**	0.72	0.65
Interest	**0.91**	1.00	1.03
Realized risk management activities loss	**1.83**	3.58	0.64
Realized foreign exchange (gain) loss	**(0.25)**	0.33	(0.09)
Taxes other than income tax – current	**0.87**	0.98	0.82
Current income tax – North America	**0.63**	0.02	0.86
Current income tax – Large Corporations Tax	**0.05**	0.09	0.08
Current income tax – North Sea	**0.81**	(0.32)	0.52
Current income tax – Offshore West Africa	**0.06**	0.07	0.07
Current income tax – other	**-**	0.03	-
Cash flow	**$ 21.14**	$ 19.46	$ 19.52

(1) Including transportation costs and excluding risk management activities.

(2) Excluding intersegment elimination.

(3) Restated to conform to current year presentation.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)	**Mar 31 2005**	Dec 31 2004
ASSETS		
Current assets		
Cash	**$ 41**	$ 28
Accounts receivable and other	**1,622**	1,176
Current portion of other long-term assets (note 2)	**-**	34
	1,663	1,238
Property, plant and equipment (net)	**17,974**	17,064
Other long-term assets (note 2)	**81**	108
	$ 19,718	$ 18,410
LIABILITIES		
Current liabilities		
Accounts payable	**$ 429**	$ 379
Accrued liabilities	**1,413**	1,057
Current portion of long-term debt (note 3)	**194**	194
Current portion of other long-term liabilities (note 4)	**915**	260
	2,951	1,890
Long-term debt (note 3)	**3,831**	3,538
Other long-term liabilities (note 4)	**1,633**	1,208
Future income tax (note 5)	**4,425**	4,450
	12,840	11,086
SHAREHOLDERS' EQUITY		
Share capital (note 6)	**2,416**	2,408
Retained earnings	**4,468**	4,922
Foreign currency translation adjustment (note 7)	**(6)**	(6)
	6,878	7,324
	$ 19,718	$ 18,410

Commitments (note 12)

Consolidated statements of earnings (loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three months ended **Mar 31 2005**	Mar 31 2004
Revenue	**$ 1,993**	$ 1,638
Less: royalties	**(259)**	(218)
Revenue, net of royalties	**1,734**	1,420
Expenses		
Production	**389**	308
Transportation	**67**	66
Depletion, depreciation and amortization	**474**	389
Asset retirement obligation accretion (note 4)	**18**	11
Administration	**35**	28
Stock-based compensation (note 4)	**184**	56
Interest	**43**	45
Risk management activities	**1,085**	130
Foreign exchange (gain) loss	**(12)**	43
	2,283	1,076
Net earnings (loss) before taxes	**(549)**	344
Taxes other than income tax	**42**	39
Current income tax expense (note 5)	**74**	66
Future income tax recovery (note 5)	**(241)**	(19)
Net earnings (loss)	**(424)**	258
Net earnings (loss) per common share (note 8)		
Basic	**$ (1.58)**	$ 0.96
Diluted	**$ (1.58)**	$ 0.96

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Three months ended **Mar 31 2005**	Mar 31 2004
Balance – beginning of period	**$ 4,922**	$ 3,650
Net earnings (loss)	**(424)**	258
Dividend on common shares (note 6)	**(30)**	(27)
Balance – end of period	**$ 4,468**	$ 3,881

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three months ended Mar 31 2005	Mar 31 2004
Operating activities		
Net earnings (loss)	**$ (424)**	$ 258
Non-cash items		
Depletion, depreciation and amortization	**474**	389
Asset retirement obligation accretion	**18**	11
Stock-based compensation	**184**	56
Unrealized risk management activities	**998**	102
Unrealized foreign exchange loss	**-**	47
Deferred petroleum revenue tax	**-**	4
Future income tax	**(241)**	(19)
Deferred charges	**(5)**	(6)
Abandonment expenditures	**(4)**	(7)
Net change in non-cash working capital	**(222)**	(152)
	778	683
Financing activities		
Issue of bank credit facilities	**273**	383
Repayment of obligations under capital leases	**-**	(6)
Issue of common shares	**2**	12
Dividend on common shares	**(27)**	(20)
Net change in non-cash working capital	**16**	(9)
	264	360
Investing activities		
Expenditures on property, plant and equipment	**(1,368)**	(1,461)
Net proceeds on sale of property, plant and equipment	**-**	2
Net expenditures on property, plant and equipment	**(1,368)**	(1,459)
Net change in non-cash working capital	**339**	338
	(1,029)	(1,121)
Increase (decrease) in cash	**13**	(78)
Cash – beginning of period	**28**	104
Cash – end of period	**$ 41**	$ 26

Supplemental disclosure of cash flow information (note 9)

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the “Company”) include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2004 except as noted below. The interim consolidated financial statements contain disclosures that are supplemental to the Company’s annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto for the year ended December 31, 2004.

Capitalized interest

The Company capitalizes interest on major development projects during the construction period based on costs incurred and the Company’s cost of borrowing. Interest capitalization ceases once construction is substantially complete.

For the three months ended March 31, 2005, the Company has capitalized interest in the amount of $11 million related to the construction of the Horizon Project.

Comparative figures

Certain figures provided for the prior year have been reclassified to conform to the presentation adopted in 2005.

Comparative figures for the prior year have been restated to reflect the retroactive adoption of CICA Section 3860 “Financial Instruments – Presentation and Disclosure” effective December 31, 2004.

2. OTHER LONG–TERM ASSETS

	Mar 31 2005	Dec 31 2004
Risk management (note 10)	**$ -**	$ 66
Deferred charges	**81**	76
	81	142
Less: current portion	**-**	34
	$ 81	$ 108

3. LONG-TERM DEBT

		Mar 31 2005		Dec 31 2004
Bank credit facilities				
Bankers' acceptances	**$**	**835**	$	-
US dollar bankers' acceptances (2005 – US$ nil, 2004 – US$471 million)		**-**		557
Medium-term notes		**125**		125
Senior unsecured notes (2005 – US$218 million, 2004 – US$218 million)		**306**		306
Preferred securities (2005 – US$80 million, 2004 – US$80 million)		**97**		96
US dollar debt securities (2005 – US$2,200 million, 2004 – US$2,200 million)		**2,662**		2,648
		4,025		3,732
Less: current portion of long-term debt		**194**		194
	$	**3,831**	$	3,538

Bank credit facilities

At March 31, 2005, the Company had unsecured bank credit facilities of $3,425 million comprised of a $100 million operating demand facility, a 364 day revolving credit and term-loan facility of $1,825 million and a $1,500 million, 5-year revolving credit facility.

Through foreign currency financial derivatives, the Company fixed the exchange rate on the repayment of its US dollar bankers' acceptances. The US dollar bankers' acceptances were repaid in January 2005 at a US$/C$ exchange rate of 0.8475.

In addition to the outstanding debt, letters of credit aggregating $25 million have been issued.

4. OTHER LONG-TERM LIABILITIES

		Mar 31 2005		Dec 31 2004
Asset retirement obligation	**$**	**1,144**	$	1,119
Stock-based compensation		**446**		323
Risk management (note 10)		**937**		-
Deferred revenue (note 10)		**21**		26
		2,548		1,468
Less: current portion		**915**		260
	$	**1,633**	$	1,208

Asset retirement obligation

At March 31, 2005, the Company's total estimated undiscounted cost to settle its asset retirement obligation with respect to crude oil and natural gas properties and facilities was $3,094 million (December 31, 2004 – $3,063 million). These costs will be incurred over several years and have been discounted using a credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligation is as follows:

	Three months ended Mar 31, 2005	Year ended Dec 31, 2004
Asset retirement obligation		
Balance – beginning of period	**$ 1,119**	$ 897
Liabilities incurred	**9**	339
Liabilities settled	**(4)**	(32)
Asset retirement obligation accretion	**18**	51
Revision of estimates	**(1)**	(86)
Foreign exchange	**3**	(50)
Balance – end of period	**$ 1,144**	$ 1,119

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

Stock-based compensation

The Company's Stock Option Plan ("Option Plan") results in the recognition of a liability for the expected cash settlements under the Option Plan. The current portion represents the amount of the liability that could be realized within the next 12 month period if all currently vested options and all options vesting during that period are surrendered for cash settlement.

	Three months ended Mar 31, 2005	Year ended Dec 31, 2004
Stock-based compensation		
Balance – beginning of period	**$ 323**	$ 171
Stock-based compensation provision	**184**	249
Current period payment for options surrendered	**(77)**	(80)
Transferred to common shares	**(6)**	(38)
Capitalized to Horizon Project	**22**	21
Balance – end of period	**446**	323
Less: current portion	**331**	243
	$ 115	$ 80

5. INCOME TAXES

The provision for income taxes is as follows:

	Three months ended	
	Mar 31 2005	Mar 31 2004
Current income tax expense		
Current income tax – North America	**$ 30**	$ 37
Large corporations tax – North America	**2**	3
Current income tax – North Sea	**39**	23
Current income tax – Offshore West Africa	**3**	3
Current income tax – Other	**-**	-
	74	66
Future income tax recovery	**(241)**	(19)
Income tax (recovery) expense	**$ (167)**	$ 47

A significant portion of the Company's North American taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependant upon the amount of capital expenditures incurred in Canada and the way it is deployed.

In March 2004, the Government of Alberta introduced legislation to reduce its corporate income tax rate by 1% effective April 1, 2004, and accordingly, the Company's future income tax liability was reduced by $66 million in the first quarter. The legislation received royal assent in May 2004.

6. SHARE CAPITAL

Issued

Common shares	Three months ended March 31, 2005 Number of shares (thousands)		Amount
Balance – beginning of period	**268,181**	**$**	**2,408**
Issued upon exercise of stock options	**129**		**2**
Previously recognized liability on stock options exercised for common shares	**-**		**6**
Purchase of shares under Normal Course Issuer Bid	**-**		**-**
Balance – end of period	**268,310**	**$**	**2,416**

Normal course issuer bid

In January, 2005, the Company announced the renewal of its Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange and the New York Stock Exchange to purchase up to 13,409,006 common shares or 5% of the outstanding common shares of the Company on the date of announcement during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at March 31, 2005, the Company had not purchased any shares under its Normal Course Issuer Bid.

Dividend policy

On February 18, 2005, the Board of Directors set the regular quarterly dividend at $0.1125 per common share (2004 - $0.10 per common share). The Company pays regular quarterly dividends in January, April, July, and October of each year.

Stock options

	Three months ended March 31, 2005 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**16,261**	**$**	**24.74**
Granted	**2,902**	**$**	**54.70**
Exercised for common shares	**(129)**	**$**	**19.24**
Surrendered for cash settlement	**(1,913)**	**$**	**19.92**
Forfeited	**(159)**	**$**	**30.31**
Outstanding – end of period	**16,962**	**$**	**30.40**
Exercisable – end of period	**4,613**	**$**	**21.15**

Share split

The Company’s Board of Directors has proposed to its shareholders to subdivide the Company’s common shares on a 2 for 1 basis. The proposal will be voted on at the Annual and Special Meeting of Shareholders to be held on May 5, 2005.

7. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

The foreign currency translation adjustment represents the unrealized gain on the Company's net investment in self-sustaining foreign operations. The Company has 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.

	Mar 31 2005
Balance – beginning of period	**$ (6)**
Unrealized gain on translation of net investment	**(1)**
Hedge of net investment with US dollar denominated debt, net of tax	**1**
Balance – end of period	**$ (6)**

8. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended	
	Mar 31 2005	Mar 31 2004(1)
Weighted average common shares outstanding (thousands)		
Basic	**268,165**	268,170
Assumed settlement of preferred securities with common shares (2)	**-**	2,982
Diluted	**268,165**	271,152
Net earnings (loss)	**$ (424)**	$ 258
Interest on preferred securities, net of tax (2)	**-**	1
Revaluation of preferred securities, net of tax(2)	**-**	1
Diluted net earnings (loss)	**$ (424)**	$ 260
Net earnings (loss) per common share		
Basic	**$ (1.58)**	$ 0.96
Diluted	**$ (1.58)**	$ 0.96

(1) Restated to reflect two-for-one share split in May 2004.

(2) Preferred securities are not dilutive for the three months ended March 31, 2005.

9. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

	Three months ended	
	Mar 31 2005	Mar 31 2004
Interest paid	**$ 44**	$ 49
Taxes paid		
Taxes other than income tax	**$ 110**	$ 44
Current income tax	**$ 111**	$ 23

10. FINANCIAL INSTRUMENTS

Risk management

On January 1, 2004, the fair values of all outstanding financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount. Subsequent changes in fair value are recognized on the consolidated balance sheet and in net earnings.

	Risk management mark-to-market	**Deferred revenue**	**Total unrealized gain/(loss)**
Balance – beginning of year	**$ 66**	**$ (26)**	
Change in fair value of existing financial instruments during the period and new financial instruments entered into in 2005	**(945)**	**-**	**$ (945)**
Put premiums	**29**	**-**	**29**
Realized risk management activities	**(87)**	**-**	**(87)**
Amortization of deferred revenue	**-**	**5**	**5**
Balance – end of period	**(937)**	**(21)**	**$ (998)**
Less: current portion	**(569)**	**(15)**	
	$ (368)	**$ (6)**	

As at March 31, 2005, the fair value of derivative financial instruments designated as hedges was a liability of $742 million (December 31, 2004 – asset of $33 million). As at March 31, 2005, the carrying value of the derivative financial instruments designated as hedges was $nil (December 31, 2004 - $nil).

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 Company has the following financial derivatives outstanding as at March 31, 2005:

	Remaining term	Volume	Average price	Index
Crude oil				
Oil price collars	Apr 2005 – Jun 2005	220,500 bbl/d	US$39.41 – US$50.54	WTI
	Jul 2005 – Sep 2005	254,500 bbl/d	US$40.97 – US$51.70	WTI
	Oct 2005 – Dec 2005	254,500 bbl/d	US$40.97 – US$51.70	WTI
	Jan 2006 – Dec 2006	175,000 bbl/d	US$38.42 – US$49.03	WTI
	Jan 2006 – Dec 2006	22,000 bbl/d	C$46.53 – C$58.67	WTI
Oil puts	Apr 2005 – Jun 2005	123,000 bbl/d	US$29.89	WTI
	Jul 2005 – Sep 2005	50,000 bbl/d	US$31.09	WTI
	Oct 2005 – Dec 2005	50,000 bbl/d	US$29.81	WTI
	Jan 2007 – Dec 2007	100,000 bbl/d	US$28.00	WTI
	Jan 2007 – Dec 2007	23,000 bbl/d	US$35.00	WTI

	Remaining term	Volume	Average price	Index
Natural gas				
AECO collars	Apr 2005 – Jun 2005	1,065,000 GJ/d	C$5.73 – C$7.73	AECO
	Jul 2005 – Sep 2005	1,065,000 GJ/d	C$5.73 – C$7.62	AECO
	Oct 2005 – Dec 2005	1,038,000 GJ/d	C$5.73 – C$8.56	AECO
	Jan 2006 – Mar 2006	1,100,000 GJ/d	C$5.92 – C$10.06	AECO
	Apr 2006 – Oct 2006	575,000 GJ/d	C$5.50 – C$7.09	AECO

	Remaining term			Amount ($ millions)	Average exchange rate (US$/C$)
Foreign currency					
Currency collars	Apr 2005	–	Aug 2005	US$10/month	1.37 – 1.49

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency swap	Apr 2005	–	Dec 2005	US$125	1.55	7.69%	7.30%
Currency forwards	Apr 2005	–	Apr 2005	US$7	1.21	n/a	n/a
	Apr 2005	–	Apr 2005	GBP [1] 4	2.29	n/a	n/a

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Apr 2005	–	Jan 2007	US$200	7.20%	LIBOR[2] + 2.23%
	Apr 2005	–	Oct 2012	US$350	5.45%	LIBOR[2] + 0.81%
	Apr 2005	–	Dec 2014	US$350	4.90%	LIBOR[2] + 0.38%
Swaps – floating to fixed	Apr 2005	–	Mar 2007	C$8	7.36%	CDOR[3]

(1) Great Britain Pounds.

(2) London Interbank Offered Rate.

(3) Canadian Deposit Overnight Rate.

11. SEGMENTED INFORMATION

	North America		North Sea		Offshore West Africa		Midstream		Other	
(millions of Canadian dollars, unaudited)	Three months ended Mar 31		Three months ended Mar 31		Three months ended Mar 31		Three months ended Mar 31		Three months ended Mar 31	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Revenue	**1,544**	1,318	**394**	263	**44**	50	21	16	-	-
Less: royalties	**(257)**	(216)	**(1)**	-	**(1)**	(2)	-	-	-	-
Revenue, net of royalties	**1,287**	1,102	**393**	263	**43**	48	**21**	**16**	**-**	**-**
Segmented expenses										
Production	**275**	219	**101**	77	**8**	9	**6**	4	**-**	**-**
Transportation	**70**	66	**6**	8	**-**	-	**-**	**-**	**-**	**-**
Depletion, depreciation and amortization	**384**	317	**82**	55	**6**	15	**2**	2	**-**	**-**
Asset retirement obligation accretion	**9**	7	**9**	4	**-**	**-**	**-**	-	**-**	**-**
Realized risk management activities	**59**	22	**28**	6	**-**	-	**-**	-	**-**	**-**
Total segmented expenses	**797**	631	**226**	150	**14**	24	**8**	6	**-**	-
Segmented earnings, before the following	**490**	471	**167**	113	**29**	24	**13**	10	**-**	-
Non-segmented expenses										
Administration										
Stock-based compensation										
Interest										
Unrealized risk management activities										
Foreign exchange (gain) loss										
Total non-segmented expenses										
Earnings (loss) before taxes										
Taxes other than income tax										
Current income tax expense										
Future income tax recovery										
Net earnings (loss)										

(millions of Canadian dollars, unaudited)	Inter-segment elimination Three months ended Mar 31		Total Three months ended Mar 31	
	2005	2004	**2005**	2004
Revenue	**(10)**	(9)	**1,993**	1,638
Less: royalties	**-**	-	**(259)**	(218)
Revenue, net of royalties	**(10)**	(9)	**1,734**	1,420
Segmented expenses				
Production	**(1)**	(1)	**389**	308
Transportation	**(9)**	(8)	**67**	66
Depletion, depreciation and amortization	**-**	-	**474**	389
Asset retirement obligation accretion	-	-	**18**	11
Realized risk management activities	-	-	**87**	28
Total segmented expenses	**(10)**	(9)	**1,035**	802
Segmented earnings, before the following	**-**	-	**699**	618
Non-segmented expenses				
Administration			**35**	28
Stock-based compensation			**184**	56
Interest			**43**	45
Unrealized risk management activities			**998**	102
Foreign exchange (gain) loss			**(12)**	43
Total non-segmented expenses			**1,248**	274
Earnings (loss) before taxes			**(549)**	344
Taxes other than income tax			**42**	39
Current income tax expense			**74**	66
Future income tax recovery			**(241)**	(19)
Net earnings (loss)			**(424)**	258

Additions to property, plant and equipment

	Three months ended	
	Mar 31 2005	Mar 31 2004
North America	**$ 949**	$ 1,471
North Sea	**57**	76
Offshore West Africa	**144**	60
Other	**4**	-
Horizon Oil Sands Project	**215**	46
Midstream	**4**	-
Head office	**4**	7
	$ 1,377	$ 1,660

	Property, plant and equipment		Total assets	
	Mar 31 2005	Dec 31 2004	**Mar 31 2005**	Dec 31 2004
Segmented assets				
North America	**$ 13,948**	$ 13,394	**$ 15,344**	$ 14,428
North Sea	**1,805**	1,823	**2,055**	2,036
Offshore West Africa	**1,051**	901	**1,121**	914
Other	**12**	8	**39**	35
Horizon Oil Sands Project	**887**	672	**887**	672
Midstream	**211**	209	**212**	268
Head office	**60**	57	**60**	57
	$ 17,974	$ 17,064	**$ 19,718**	$ 18,410

12. Commitments

The Company has committed to certain payments as follows:

	2005	2006	2007	2008	2009	Thereafter
Natural gas transportation	$ 150	$ 166	$ 103	$ 79	$ 38	$ 167
Oil transportation and pipeline	$ 8	$ 9	$ 11	$ 12	$ 13	$ 154
FPSO operating lease	$ 66	$ 48	$ 48	$ 48	$ 48	$ 185
Baobab Project	$ 52	$ -	$ -	$ -	$ -	$ -
Offshore drilling and other	$ 130	$ 6	$ -	$ -	$ -	$ -
Electricity	$ 27	$ 39	$ 41	$ -	$ -	$ -
Office lease	$ 15	$ 21	$ 22	$ 23	$ 24	$ 30
Processing	$ 4	$ 2	$ -	$ -	$ -	$ -

Total capital costs for the three phases of the Horizon Project development are expected to be approximately $10.8 billion. The Board of Directors has approved the capital costs for the first phase of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion incurred in 2006, 2007 and 2008 respectively.

13. Subsequent event

On April 20, 2005, the Company announced the disposition of a large portion of its overriding royalty interests on various producing properties throughout Western Canada and Ontario for proceeds of approximately $345 million, after giving effect to anticipated adjustments. The transaction is expected to close on or about May 10, 2005 subject to the receipt of required regulatory approvals and standard closing conditions. Net proceeds received upon closing will be applied to reduce bank credit facilities.

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short-form prospectus dated August 2003. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the 12-month period ended March 31, 2005:	
Interest coverage (times)	
Net earnings[(1)]	6.8x
Cash flow from operations[(2)]	22.5x

(1) Net earnings plus income taxes and interest expense; divided by interest expense.

(2) Cash flow from operations plus current income taxes and interest expense; divided by interest expense.

Forward-Looking Statements

Certain statements in this document or documents incorporated herein by reference 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: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; the potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the asset retirement obligations; 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.

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data is presented on a before royalties basis unless otherwise stated. In addition, reference is made to oil and gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6mcf:1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

Canadian Natural retains qualified independent reserves evaluators, to evaluate 100% of the Company's proved and probable crude oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Canadian Natural has been granted an exemption from the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. Canadian Natural has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves. As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material. The Board of Directors of the Company has a Reserves Committee, which has met with the Company's third party reserve evaluators and carried out independent due diligence procedures with them as to the Company's reserves.

Reserves and Net Asset Values presented for years prior to 2003 were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and constant pricing as at December 31, 2005 throughout the productive life of the properties. For further information on pricing assumptions used for each year, please refer to the Company's Annual Information Form as filed on www.sedar.com, or the Company's Annual Report.

Horizon Oil Sands mining reserves have been evaluated under SEC Industry Guide 7 as at February 9, 2005. Resource potential as determined for thermal crude oil assets and other potential mining leases are determined using generally accepted industry methodologies for resource delineation based upon stratigraphic well drilling completed on the properties. They are not considered reserves of the Company for purposes of regulatory filings as regulatory approvals may not have been received or formal development plans may not have been approved by the Board of Directors.

Special Note Regarding non-GAAP Financial Measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as adjusted net earnings from operations, cash flow, cash flow per share and EBITDA (net earnings before interest, taxes, depreciation depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate the performance of the Company and of its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

CORPORATE INFORMATION

Officers

Allan P. Markin*
Chairman of the Board

N. Murray Edwards*
Vice-Chairman of the Board

John G. Langille*
Vice-Chairman of the Board

Steve W. Laut*
President & Chief Operating Officer

Douglas A. Proll*
Chief Financial Officer &
Senior Vice-President, Finance

Réal M. Cusson*
Senior Vice-President, Marketing

Réal J.H. Doucet*
Senior Vice-President, Oil Sands

Allen M. Knight*
Senior Vice-President, International & Corporate Development

Tim S. McKay*
Senior Vice-President, North America Operations

Lyle G. Stevens*
Senior Vice-President, Exploitation

Jeff W. Wilson*
Senior Vice-President, Exploration

Martin Cole*
Vice-President and Managing Director, CNR International (UK) Limited

Mary-Jo E. Case*
Vice-President, Land

Corey B. Bieber
Vice-President, Investor Relations

Wayne M. Chorney
Vice-President, Development Operations

William R. Clapperton
Vice-President, Regulatory, Stakeholder & Environmental Affairs

*Management Committee

Gordon M. Coveney
Vice-President, Exploration - East

Randall S. Davis
Vice-President, Financial Accounting & Controls

Larry C. Galea
Vice-President, Operations Planning

Jerry W. Harvey
Vice-President, Commercial Operations

Peter J. Janson
Vice-President, Engineering Integration

Terry J. Jocksch
Vice-President, Exploitation - East

Christopher M. Kean
Vice-President, Utilities & Offsites

Philip A. Keele
Vice-President, Mining

Cameron S. Kramer
Vice-President, Field Operations

León Miura
Vice-President, Upgrading

S. John Parr
Vice-President, Production - East

David A. Payne
Vice-President, Exploitation - West

Bill R. Peterson
Vice-President, Production - West

John C. Puckering
Vice-President, Site Development

Sheldon L. Schroeder
Vice-President, Project Control

Ken W. Stagg
Vice-President, Exploration, West

Lynn M. Zeidler
Vice-President, Bitumen Production

Bruce E. McGrath
Corporate Secretary

Kimberly I. McKay
Treasurer

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ and CNQ.U*

*denotes trading in US funds

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

Catherine M. Best

N. Murray Edwards

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