

Canadian Natural

**Q2** **Six Months Ended June 30, 2005**

# CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY PRODUCTION AND CASH FLOW

In commenting on first half 2005 results, Canadian Natural's Chairman, Allan Markin, stated "The execution of our defined path for profitable growth continues on track. Our existing operations are delivering expected results and management continues to drive the delivery of several key development projects. Our financial position remains exceptionally strong which allows us to continue building one of the most solid, sustainable energy producers in the world."

Steve Laut, President and Chief Operating Officer of Canadian Natural added, "Our operating divisions are delivering. As a result of our activities during the second quarter, our third quarter production volumes are expected to increase by about 43 thousand barrels of oil equivalent per day or 8%. In Canada, today we are producing approximately 460 thousand barrels per day of oil equivalents, reflecting our exploitation program that continues to deliver results. In the third quarter, the North Sea is coming out of maintenance and is currently at record production levels, our Primrose development is exceeding expectations and our Baobab development in Côte d'Ivoire is coming on stream in early August, only 4.5 years from initial discovery – ranking amongst the best performances in the West Africa deep-water basin. Finally, our world class Horizon Oil Sands Project continued on-time and on-budget with over 500 workers on site and detailed engineering continuing at vendors offices located throughout Europe and North America."

**HIGHLIGHTS**

| | Quarterly Results | | | Six Month Results | |
|---|---|---|---|---|---|
| ($ millions, except as noted) | **Q2/05** | Q1/05 | Q2/04 | **2005** | 2004 |
| Net earnings (loss) | **$ 219** | $ (424) | $ 259 | **$ (205)** | $ 517 |
| per common share, basic[1] | **$ 0.41** | $ (0.79) | $ 0.48 | **$ (0.38)** | $ 0.96 |
| Adjusted net earnings from operations[2] | **$ 460** | $ 380 | $ 364 | **$ 840** | $ 703 |
| per common share, basic[1] | **$ 0.86** | $ 0.71 | $ 0.68 | **$ 1.57** | $ 1.31 |
| Cash flow from operations[3] | **$ 1,136** | $ 1,009 | $ 930 | **$ 2,145** | $ 1,778 |
| per common share, basic[1] | **$ 2.12** | $ 1.88 | $ 1.73 | **$ 4.00** | $ 3.32 |
| Capital expenditures, net of dispositions | **$ 609** | $ 1,372 | $ 844 | **$ 1,981** | $ 2,337 |
| Debt to book capitalization[4] | **35%** | 37% | 36% | **35%** | 36% |
| Daily production, before royalties | | | | | |
| Natural gas (mmcf/d) | **1,454** | 1,455 | 1,452 | **1,455** | 1,373 |
| Crude oil and NGLs (mbbl/d) | **289.1** | 287.8 | 275.4 | **288.4** | 268.3 |
| Equivalent production (mboe/d) | **531.4** | 530.3 | 517.3 | **530.9** | 497.1 |

*[1] Per share amounts restated to reflect two-for-one common share split in May 2005.*

*[2] Adjusted net earnings from operations is a non-GAAP term that the Company utilizes to evaluate its performance. The derivation of this item is discussed in the MD&A.*

*[3] Cash flow from operations is a non-GAAP term that the Company considers key as it demonstrates its ability to fund capital reinvestment and debt repayment. The derivation of this item is discussed in the MD&A.*

*[4] Includes current portion of long-term debt.*

- Record cash flow generation during Q2/05 of over $1.1 billion, a 22% improvement over Q2/04 and a 13% improvement over Q1/05.
- Strong quarterly adjusted net earnings from operations of $460 million, representing a 26% increase over Q2/04 and 21% increase over Q1/05.
- Record quarterly production volumes, 3% higher than Q2/04 and 1 mboe/d higher than Q1/05. Quarterly natural gas production represents 46% of equivalent production and 53% of Canadian equivalent production.
- Q3/05 midpoint guidance of 574 mboe/d represents an increase of 43 mboe/d or 8% from Q2/05 levels and Q3/04 levels.
- First half loss of $205 million included charges of:
  - $0.8 billion after tax for the unrealized mark-to-market of the Company's commodity hedge position, effectively recognizing commodity strip price strength at June 30 for hedged production for the second half of 2005 and future years in the year to date,
  - $0.3 billion after tax for revaluation of stock option liability to reflect stock price appreciation in the first six months of the year.
- Successful second quarter drilling program of 225 net wells, excluding stratigraphic test and service wells, with a 93% success ratio, reflecting Canadian Natural's strong, predictable, low risk asset base.
- Continued strong undeveloped conventional land base in Canada of 11.1 million net acres – a key asset in today's highly competitive industry.
- Completed the disposition of a large portion of its overriding royalty interests, which were considered non-core to the Company's operations, for proceeds of approximately $345 million.
- Facilities for the offshore Baobab Field in Côte d'Ivoire were essentially completed by the end of the quarter. Final commissioning is currently underway with first production expected in early August.
- Following successful completion of scheduled platform maintenance in the North Sea during Q2/05, current production levels are approximately 80 mbbl/d of crude oil, up 27% from Q2/05 levels.
- Horizon Oil Sands Project remained on budget and on schedule with site preparation and construction work completed as planned.
- The Company issued C$400 million in 10-year notes at a rate of 4.95%.
- Strong balance sheet maintained with debt to book capitalization of 35%.
- The 2005 second quarter dividend increased 7% from $0.05625 per common share to $0.06 per common share.

## CORPORATE UPDATE

Canadian Natural is pleased to announce that Norman F. McIntyre has been appointed a member of the Board of Directors of the Company. Mr. McIntyre, until his recent retirement, was a senior officer of one of Canada's largest integrated crude oil and natural gas companies, with operations in Canada and around the world. Mr. McIntyre brings with him over 40 years of experience in all aspects of the crude oil and natural gas industry including large scale project execution and oil sands development.

## 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 June 30, 2005 (thousands of net acres) | Drilling activity six months ended June 30, 2005 (net wells) |
|---|---|---|
| Canadian conventional | | |
| Northeast British Columbia | **2,026** | **191** |
| Northwest Alberta | **1,617** | **84** |
| Northern Plains | **6,679** | **430** |
| Southern Plains | **644** | **71** |
| Southeast Saskatchewan | **84** | **20** |
| | **11,050** | **796** |
| Horizon Oil Sands Project | **116** | **122** |
| United Kingdom North Sea | **511** | **6** |
| Offshore West Africa | **886** | **3** |
| | **12,563** | **927** |

**Drilling activity** (number of wells)

| | Six months ended June 30 | | | |
|---|---|---|---|---|
| | **2005** | | 2004 | |
| | **Gross** | **Net** | Gross | Net |
| Crude oil | **290** | **258** | 196 | 185 |
| Natural gas | **456** | **398** | 492 | 444 |
| Dry | **80** | **72** | 77 | 72 |
| Subtotal | **826** | **728** | 765 | 701 |
| Stratigraphic test / service wells | **201** | **199** | 271 | 270 |
| Total | **1,027** | **927** | 1,036 | 971 |
| Success rate (excluding stratigraphic test / service wells) | | **90%** | | 90% |

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** | **Q2/05** | | Q1/05 | | Q2/04 | |
|---|---|---|---|---|---|---|
| | **mboe/d** | **%** | mboe/d | % | mboe/d | % |
| Natural gas | **242.3** | **46** | 242.5 | 46 | 241.9 | 47 |
| Light crude oil and NGLs | **126.3** | **24** | 132.6 | 25 | 118.7 | 23 |
| Pelican Lake crude oil | **20.0** | **4** | 17.9 | 3 | 19.6 | 4 |
| Primary heavy crude oil | **92.2** | **17** | 92.0 | 17 | 101.4 | 19 |
| Thermal heavy crude oil | **50.6** | **9** | 45.3 | 9 | 35.7 | 7 |
| Total | **531.4** | **100** | 530.3 | 100 | 517.3 | 100 |

**North American natural gas**

| | Quarterly Results | | | Six Month Results | |
|---|---|---|---|---|---|
| | **Q2/05** | Q1/05 | Q2/04 | **2005** | 2004 |
| Natural gas production (mmcf/d) | **1,434** | 1,430 | 1,389 | **1,432** | 1,310 |
| Net wells targeting natural gas | **68** | 386 | 88 | **454** | 512 |
| Net successful wells drilled | **60** | 338 | 86 | **398** | 444 |
| Success rate | **88%** | 88% | 98% | **88%** | 87% |

- Q2/05 natural gas production represented a 3% increase over Q2/04 and maintained Q1/05 levels.
- Canadian Natural growth rates for Q3/05, Q4/05 and annual 2005 volumes are expected to approach 5% when compared to the previous year, a further reflection of the balanced drilling program. Q3/05 drilling activity is expected to total 267 wells, including approximately 104 shallow wells in the Southern Plains. This program combined with current North American production levels of approximately 1,420 mmcf/d, will result in third quarter production of 1,400 mmcf/d to 1,430 mmcf/d.
- During Q2/05 Alberta encountered much higher than normal precipitation levels with resulting extensive flooding and road closures throughout portions of the Province. While the Company plans for a variety of weather contingencies the unusual level of precipitation was not foreseeable. Hence, this phenomenon had an impact on mobilization, drilling, completion, tie-in and maintenance activities. As at the date of this release, 9 of the 34 drill rigs currently contracted by the Company remained immobilized due to the impact of residual moisture. This will impact third quarter drilling efforts in both natural gas and heavy crude oil and is reflected in quarterly guidance.
- Given that Canadian Natural made the strategic decision to control inflationary pressures through a more balanced distribution of drilling activities throughout the year, drilling activity for the second quarter was 78% of that of the previous year. However, due to wet weather, tie-ins of new wells were delayed and approximately 50 mmcf/d of production remains stranded. While not material to the overall corporate activities this did result in 1.4% lower than expected quarterly natural gas production volumes and will result in a reduction of annual midpoint natural gas guidance of approximately 1.7%. Canadian Natural continues to believe that a balanced drilling approach will yield better cost control as peak drill rig utilization is reduced at high demand periods.
- High success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q2/05 natural gas drilling program consisted of 8 net wells in Northwest Alberta, 47 net wells in the Southern Plains, and 13 net wells in the Northern Plains.

**North American crude oil and NGLs**

| | Quarterly Results | | | Six Month Results | |
|---|---|---|---|---|---|
| | **Q2/05** | Q1/05 | Q2/04 | **2005** | 2004 |
| Crude oil and NGLs production (mbbl/d) | **216** | 209 | 204 | **212** | 198 |
| Net wells targeting crude oil | **153** | 114 | 40 | **267** | 183 |
| Net successful wells drilled | **146** | 106 | 39 | **252** | 179 |
| Success rate | **95%** | 93% | 98% | **94%** | 98% |

- Q2/05 crude oil drilling activity was concentrated in the Northern Plains with 138 net crude oil wells. Included in this amount were 62 primary heavy crude oil wells that are expected to yield production increases in the third quarter as primary heavy crude oil wells typically increase production through the first six months of their productive lives.
- The Primrose North Field expansion continued with the drilling of 53 new wells in Q2/05. Production from the pads at Primrose is subject to the cycling of steam injection and crude oil production. Due to such normal cycling activities, average thermal crude oil production levels in Q2/05 were 15 mbbl/d or 42% higher than Q2/04. It is expected that additional new well pads will come on stream in Q3/05, increasing production levels before decreasing in Q4/05 for another steam cycle. Primrose North expansion pads continue to produce at rates approximately 30% better than expected while project development continues on plan. Due to the success of this program, certain facets of the development have been accelerated resulting in $70 million of additional capital expenditures also being accelerated from 2006.
- The Pelican Lake waterflood expansion continued successfully from first quarter with the drilling of 12 additional producing wells interspaced between previously converted injection wells to complete three more waterflood pad patterns. All water injector conversions are now complete for 2005. Water is being actively injected to obtain optimal voidage replacement prior to drilling the final group of producing wells in Q3/05. Production levels for Pelican Lake have increased by 2 mbbl/d or 12% over Q1/05 as Canadian Natural continues to see positive waterflood performance.
- Canadian Natural also drilled a combination of 12 new single-leg and multi-leg primary wells in Pelican Lake during Q2/05. Due to these positive results, Canadian Natural is moving to a 3 rig drilling program with a further 60 wells expected to be drilled over the second half of 2005.
- 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.
- During the second quarter, the Company blended approximately 130 mbbl/d of crude oil. The majority of heavier crude oils were contributed to the Western Canadian Select ("WCS") stream as market conditions resulted in this stream offering the optimal pricing for bitumen.
- The Company has committed to 25 mbbl/d of new pipeline capacity on the reversal of the Corsicana Pipeline, which will carry heavy 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.
- Q3/05 drilling activity will include approximately 200 wells in the Northern Plains, including 136 primary heavy crude oil wells. This program, combined with current North American production levels of approximately 225 mbbl/d and anticipated oil cycles on thermal projects, will result in third quarter production of 220 mbbl/d to 230 mbbl/d, an increase of 2%-7% over Q2/05 levels.

**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.

| | Quarterly Results | | | Six Month Results | |
|---|---|---|---|---|---|
| | **Q2/05** | Q1/05 | Q2/04 | **2005** | 2004 |
| Total crude oil production (mbbl/d) | | | | | |
| North Sea | **63** | 71 | 60 | **67** | 59 |
| Offshore West Africa | **10** | 8 | 11 | **9** | 12 |
| Total natural gas production (mmcf/d) | | | | | |
| North Sea | **17** | 23 | 55 | **20** | 54 |
| Offshore West Africa | **3** | 2 | 8 | **3** | 9 |
| Net wells targeting crude oil | **4.2** | 2.9 | 3.5 | **7.1** | 7.0 |
| Net successful wells drilled | **3.4** | 2.3 | 2.5 | **5.7** | 6.0 |
| Success rate | **81%** | 79% | 71% | **80%** | 86% |

*North Sea*

- Canadian Natural continues to execute its exploitation plans in the North Sea. Q2/05 production levels decreased from Q1/05 levels due to scheduled maintenance as well as production curtailments resulting from third party natural gas export restrictions. These issues were resolved during Q2/05 with current production levels from the basin at approximately 80 mbbl/d of crude oil and 22 mmcf/d of natural gas.
- During Q2/05, 3.6 net wells were drilled with an additional 3.5 net wells drilling at quarter end.
- During Q2/05, approximately 22 mbbl/d of production from the Ninian South Platform was suspended for three weeks in order to facilitate a scheduled maintenance shut down. This affected production levels from a portion of the Ninian Field as well as the Lyell Field and the Columbas Terraces.
- Re-pressurization of the Ninian Field continued in the second quarter after the Q4/04 loss of a power turbine used to drive water injection on the Ninian North Platform 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 continued to recover. Ninian production averaged 20 mbbl/d compared with 17 mbbl/d during Q1/05. Current production levels are 24 mbbl/d net to Canadian Natural.
- At the Murchison Platform, oil production was constrained by approximately 2 mbbl/d averaged over the quarter by the shut in of third party export facilities. Current production levels are approximately 15 mbbl/d.
- On the T-Block, the execution of exploitation plans commenced and the major refurbishment of the Tiffany Platform drilling rig was completed with a two well program underway. Production from the first of these wells, in conjunction with intervention work on the Toni and Thelma Fields, has added approximately 3 mboe/d late in Q2/05. In addition, on Thelma, two wells are scheduled to spud later this year, targeting unswept areas of the field.
- Commencing late in Q3/05, production from the Kyle Field will be processed through the Banff Floating Production Storage and Offtake vessel ("FPSO"). The existing Kyle FPSO will be released in September 2005. The consolidation of these production facilities are expected to result in lower combined operating costs from these fields and will ultimately extend field lives for both fields.
- During the third quarter 4 net wells are expected to be completed, while third quarter production expectations are
  80 mboe/d to 89 mboe/d, a 22% to 35% improvement over Q2/05.
- Canadian Natural continues to utilize its mature basin expertise, and will continue to evaluate accretive acquisition opportunities with exploitation upside potential.

*Offshore West Africa*

- The development of the 57.61% owned and operated Baobab Field, located offshore Côte d'Ivoire, was essentially complete at quarter end, with minor optimizations occurring in July prior to final commissioning. First oil from the field is expected in early August at a rate of 25 mbbl/d net to Canadian Natural, increasing to approximately 35 mbbl/d by year end. Completion of this project is a significant indicator of the high level of expertise that Canadian Natural has achieved since entering the offshore production arena in 2000. Baobab, a deep water development, was first discovered by Canadian Natural in Q1/01 and will be brought on stream in 4.5 years and within the Company's budgeted costs in a highly competitive environment.
- Net production at East Espoir continues to meet expectations, averaging 11 mboe/d during Q2/05. The infill drilling program of four additional wells commenced in the quarter with the first of the wells coming on stream in late June at an initial rate of 1.1 mbbl/d. Production from the remaining wells will further increase production over the second half of the year.
- The West Espoir drilling tower, which will facilitate development drilling of this reservoir, is currently under construction, progressing on time and within budget. First crude oil from West Espoir is expected in mid 2006 delivering 13 mboe/d when fully commissioned.

**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 are targeted for 2012, following completion of Phase 3 construction.
- The high degree of up front project engineering and pre-planning has reduced the risks on "cost-plus" aspects of the project and will mitigate the risk of scope changes on the fixed bid portions (68% of Phase 1 costs). 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 considered 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 Phase 1 of the Horizon Project will be, including a contingency fund of $700 million, $6.8 billion with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008 respectively.
- The quarterly update for the project is as follows:

| *Project status summary* | **June 30, 2005** | | Sep 30, 2005 |
|---|---|---|---|
| | **Actual** | Plan | Plan |
| Work progress (cumulative) | **6%** | 6% | 14% |
| Capital spending (cumulative) | **6%** | 7% | 13% |

*Accomplished during the second quarter*

- All project areas were fully staffed and overall detailed engineering was 27% complete and on schedule with over 1,000 engineering professionals working on the project design.
- Total procurement progress is at $3.3 billion awarded contracts and purchase orders, with a further $500 million in the tender stages.
- Several common service and infrastructure agreements (i.e. concrete, camp catering, etc.) have been established with local and regional suppliers.
- Module construction is well underway for the main piperack, with over 90% of the bulk materials received at the fabricator's yards.

- Achieved the project milestone of over 1 million manhours of site work during the quarter. Project to date is 1.4 million manhours worked on site.
- All plant and initial mine area clearing were completed during the quarter.
- Site grading and installation of deep underground utilities were approximately 50% complete and on schedule.
- First plant site turnover to an EPC contractor was achieved on schedule for the coker foundations.
- Completed construction of the first of three plant site camps.
- Construction of temporary natural gas supply, water and sewage treatment plants and power supply was completed.
- Overburden removal in the mine area commenced three weeks ahead of schedule.

*Q3/2005 milestones*

- Occupancy of the first of three on-site camps, built to accommodate up to 1,500 construction personnel.
- Completion and commissioning of the site aerodrome landing strip (capable of handling up to 737-size aircraft).
- Detailed engineering planned to be over 60% complete.
- Receive shipment of first modules on main piperack.
- Ramp up of overburden removal operation to 60,000 tonnes / day.
- Turnover plant site areas for Hydrotreating and Extraction foundation construction.

A picture gallery providing visual updates on construction progress is available on the Company's website at http://www.cnrl.com/horizon/updates/photo_gallery.html.

## MARKETING

| | Quarterly Results | | | Six Months Results | |
|---|---|---|---|---|---|
| | **Q2/05** | Q1/05 | Q2/04 | **2005** | 2004 |
| Crude oil and NGLs pricing | | | | | |
| WTI benchmark price (US$/bbl) | **$ 53.13** | $ 49.90 | $ 38.34 | **$ 51.53** | $ 36.75 |
| Lloyd Blend Heavy oil differential from WTI (%) | **40%** | 39% | 30% | **39%** | 29% |
| US/Canada average exchange rate | **$ 0.8038** | $ 0.8152 | $ 0.7358 | **$ 0.8094** | $ 0.7471 |
| Corporate average pricing before hedging activities (C$/bbl) | **$ 42.51** | $ 39.81 | $ 36.72 | **$ 41.17** | $ 35.49 |
| Natural gas pricing | | | | | |
| AECO benchmark price (C$/GJ) | **$ 7.00** | $ 6.35 | $ 6.45 | **$ 6.67** | $ 6.35 |
| Corporate average pricing before hedging activities (C$/mcf) | **$ 7.33** | $ 6.68 | $ 6.64 | **$ 7.01** | $ 6.48 |

- Crude oil and NGLs pricing benefited from higher WTI reference pricing, partially offset by continued higher than normal 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 historical average level. Continued high crack spreads coupled with limited North American refining capacity has resulted in an extension of this light oil premium into mid-2005.
- The level of differential has recently narrowed substantially with July differentials of 24% being realized. The Company's current expectations for average differentials over the next twelve months are approximately 32%.

## 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 555 mboe/d, comprised of 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 – $3.425 billion of bank credit facilities. In the aggregate, Canadian Natural had $3.2 billion of unused bank lines available at June 30, 2005.
  - Strong balance sheet – with a debt to book capitalization ratio of 35%, debt to cash flow of 0.9x, debt to EBITDA of 0.8x and shareholders' equity of $7.1 billion.
  - Financial flexibility – Canadian Natural's 5- and 10-year business 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.
- To ensure adequate free cash flow from conventional crude oil and natural gas operations to fund the Horizon Project, Management may hedge up to 75% of the near 12 months budgeted 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 policy, approximately 70% of budgeted 2005 and 50% of expected 2006 crude oil volumes have been hedged. Approximately 70% of budgeted 2005 and 50% 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 increase in crude oil prices at the end of June 2005, Canadian Natural recorded an after-tax expense of approximately $760 million on its risk management activities. This unrealized risk management expense reflects, at June 30, 2005, the implied price differentials for the non-designated hedges for the second half of 2005 and future years. This does not affect the Company's 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 its capital expenditure program, including the Horizon Project and does not plan to 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.
- In May 2005 the Company issued C$400 million in 10 year notes at a rate of 4.95%.
- In May 2005 the Company further increased common share dividends from C$0.05625 per share to $0.06 per share. This 7% increase represents the fifth increase in dividend rates since the program's creation in 2001.
- In June 2005 the Company updated its short form shelf prospectus, allowing for the issue of up to US$2 billion debt securities in the United States until July 2007.

## OUTLOOK

The Company currently expects 2005 production levels before royalties to average 1,432 to 1,474 mmcf/d of natural gas and 312 to 335 mbbl/d of crude oil and NGLs. Q3/05 production guidance before royalties is 1,423 to 1,468 mmcf/d of natural gas and 322 to 344 mbbl/d of crude oil and NGLs.

Capital expenditure levels have been increased in Canada by $350 million to reflect accelerated spending on the Primrose thermal development and the expansion of the Pelican Lake drilling program. This increase also reflects general inflationary pressures and additional costs incurred as a direct result of the wet weather. Drill rigs are generally contracted on day rate basis, and due to mobility issues the utilization of these rigs has not been as effective as would otherwise be expected.

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 and six months ended June 30, 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 financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The financial measures, adjusted net earnings from operations and cash flow from operations, referred to in this MD&A, are not prescribed by GAAP and are reconciled in the "Financial Highlights" section.

Certain prior period amounts have been reclassified to enable comparison with the current period's presentation.

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 crude 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 presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices exclude the effect of risk management activities, except where noted otherwise. Production net of royalties is presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the three and six months ended June 30, 2005 in relation to the comparable periods in 2004 and the first quarter in 2005. The accompanying tables form an integral part of this MD&A. This MD&A is dated July 29, 2005.

## FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005(1) | Jun 30 2004 (1) | **Jun 30 2005** | Jun 30 2004 (1) |
| Revenue, before royalties | **$ 2,164** | $ 1,993 | $ 1,865 | **$ 4,157** | $ 3,503 |
| Net earnings (loss) | **$ 219** | $ (424) | $ 259 | **$ (205)** | $ 517 |
| Per common share – basic | **$ 0.41** | $ (0.79) | $ 0.48 | **$ (0.38)** | $ 0.96 |
| – diluted | **$ 0.41** | $ (0.79) | $ 0.48 | **$ (0.38)** | $ 0.96 |
| Adjusted net earnings from operations(2) | **$ 460** | $ 380 | $ 364 | **$ 840** | $ 703 |
| Per common share – basic | **$ 0.86** | $ 0.71 | $ 0.68 | **$ 1.57** | $ 1.31 |
| – diluted | **$ 0.86** | $ 0.71 | $ 0.68 | **$ 1.57** | $ 1.31 |
| Cash flow from operations(3) | **$ 1,136** | $ 1,009 | $ 930 | **$ 2,145** | $ 1,778 |
| Per common share – basic | **$ 2.12** | $ 1.88 | $ 1.73 | **$ 4.00** | $ 3.32 |
| – diluted | **$ 2.12** | $ 1.88 | $ 1.73 | **$ 4.00** | $ 3.32 |
| Capital expenditures, net of dispositions | **$ 609** | $ 1,372 | $ 844 | **$ 1,981** | $ 2,337 |

*(1) Per share amounts restated to reflect a two-for-one common share split in May 2005.*

*(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.*

| | *Three Months Ended* | | | *Six Months Ended* | |
|---|---|---|---|---|---|
| *($ millions)* | ***Jun 30 2005*** | *Mar 31 2005* | *Jun 30 2004* | ***Jun 30 2005*** | *Jun 30 2004* |
| *Net earnings (loss) as reported* | ***$ 219*** | *$ (424)* | *$ 259* | ***$ (205)*** | *$ 517* |
| *Unrealized foreign exchange loss, net of tax (a)* | ***14*** | *-* | *28* | ***14*** | *66* |
| *Unrealized risk management loss, net of tax (b)* | ***81*** | *679* | *47* | ***760*** | *115* |
| *Stock-based compensation, net of tax (c)* | ***146*** | *125* | *30* | ***271*** | *71* |
| *Effect of statutory tax rate changes on future income tax liabilities (d)* | ***-*** | *-* | *-* | ***-*** | *(66)* |
| *Adjusted net earnings from operations* | ***$ 460*** | *$ 380* | *$ 364* | ***$ 840*** | *$ 703* |

*a) Unrealized foreign exchange losses primarily result 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 net earnings. The amounts ultimately realized 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 based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt.*

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| *($ millions)* | ***Jun 30 2005*** | *Mar 31 2005* | *Jun 30 2004* | ***Jun 30 2005*** | *Jun 30 2004* |
| *Net earnings (loss)* | ***$ 219*** | *$ (424)* | *$ 259* | ***$ (205)*** | *$ 517* |
| *Non-cash items:* | | | | | |
| *Depletion, depreciation and amortization* | ***484*** | *474* | *426* | ***958*** | *815* |
| *Asset retirement obligation accretion* | ***17*** | *18* | *10* | ***35*** | *21* |
| *Stock-based compensation* | ***215*** | *184* | *50* | ***399*** | *106* |
| *Unrealized risk management activities* | ***119*** | *998* | *70* | ***1,117*** | *172* |
| *Unrealized foreign exchange loss* | ***16*** | *-* | *36* | ***16*** | *83* |
| *Deferred petroleum revenue tax (recovery)* | ***4*** | *-* | *(3)* | ***4*** | *1* |
| *Future income tax expense (recovery)* | ***62*** | *(241)* | *82* | ***(179)*** | *63* |
| *Cash flow from operations* | ***$ 1,136*** | *$ 1,009* | *$ 930* | ***$ 2,145*** | *$ 1,778* |

## SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the six months ended June 30, 2005, the Company recorded a loss of $205 million compared to net earnings of $517 million in 2004. The loss for the first half of 2005 included unrealized after-tax expenses of $1,045 million related to the Company's risk management activities, stock-based compensation plans and foreign exchange, compared to $252 million in the comparable period in 2004. Excluding the effects of these items, adjusted net earnings from operations increased 19% to $840 million from $703 million in the comparable period in 2004 due to the continuation of strong commodity prices as well as record levels of total production.

For the second quarter 2005, the Company reported net earnings of $219 million compared to net earnings of $259 million in the second quarter 2004 and a loss of $424 million for the first quarter 2005. Net earnings in the second quarter of 2005 included unrealized after-tax expenses of $241 million related to risk management activities, stock-based compensation plans and foreign exchange, compared to $105 million in the second quarter of 2004 and $804 million in the first quarter of 2005. Excluding these items, adjusted net earnings from operations in the second quarter of 2005 increased by 26% to $460 million from $364 million in the comparable period in 2004, and increased 21% from $380 million in the prior quarter.

The Company expects that consolidated net earnings will continue to reflect significant quarterly volatility due to the impact of risk management activities, stock-based compensation and foreign exchange.

In January 2005, the Board of Directors authorized the expansion of the Company's economic hedging program to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow for its capital expenditure program through the Horizon Project construction period. This expanded program allows for the economic hedging of up to 75% of the near 12 months budgeted 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 70% of 2005 budgeted crude oil volumes and approximately 50% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 70% of 2005 budgeted natural gas volumes and approximately 50% 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 9 to the consolidated financial statements.

As effective as economic hedges are against reference commodity prices, a substantial portion of the crude oil related financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the "non-designated hedges"). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, the unrealized risk management expense reflects, at June 30, 2005, the implied price differentials for the non-designated hedges for the remainder of 2005 and future years. Primarily due to the dramatic increase in crude oil forward pricing in 2005, the Company recorded a $1,117 million ($760 million after tax) unrealized loss on its risk management activities for the six months ended June 30, 2005, including a $119 million ($81 million after tax) unrealized loss for the three months ended June 30, 2005. This unrealized loss does not affect the Company's cash flow or its 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.

The Company also recorded a $399 million ($271 million after tax) stock-based compensation expense for the six months ended June 30, 2005 in connection with the 73% appreciation in the Company's share price, and a $215 million ($146 million after tax) stock-based compensation expense as a result of the 30% appreciation in the Company's share price in the second quarter of 2005 (June 30, 2005 - C$44.40; March 31, 2005 - C$34.18; December 31, 2004 - C$25.63). As required by GAAP, the Company's outstanding stock options are carried at fair value based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect the changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in stock-based compensation expense in the period. The stock-based compensation liability reflects the Company's potential cash liability should all the expensed options be surrendered for a cash payout at the market price on June 30, 2005. In periods when substantial stock price changes occur, the

Company is subject to significant earnings volatility. 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 six months ended June 30, 2005 increased 21% to $2,145 million from $1,778 million for the comparable period in 2004. Cash flow from operations in the second quarter of 2005 increased to $1,136 million, up 22% from $930 million for the second quarter of 2004 and up 13% from $1,009 million in the prior quarter respectively. The increase in cash flow from operations was due mainly to strong commodity prices and record levels of total production on a boe basis.

Total production averaged 530,851 boe/d for the six months ended June 30, 2005, up 7% from 497,143 boe/d in the comparable period in 2004. Production for the second quarter of 2005 increased 3% to 531,380 boe/d from 517,343 boe/d in the second quarter of 2004.

**OPERATING HIGHLIGHTS**

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** ($/bbl, except daily production) | | | | | |
| Daily production, before royalties (bbl/d) | **289,064** | 287,803 | 275,398 | **288,437** | 268,342 |
| Sales price (1) | **$ 42.51** | $ 39.81 | $ 36.72 | **$ 41.17** | $ 35.49 |
| Royalties | **3.33** | 3.39 | 3.15 | **3.36** | 3.03 |
| Production expense | **11.66** | 11.30 | 9.92 | **11.48** | 9.75 |
| Netback | **$ 27.52** | $ 25.12 | $ 23.65 | **$ 26.33** | $ 22.71 |
| **Natural gas** ($/mcf, except daily production) | | | | | |
| Daily production, before royalties (mmcf/d) | **1,454** | 1,455 | 1,452 | **1,455** | 1,373 |
| Sales price (1) | **$ 7.33** | $ 6.68 | $ 6.64 | **$ 7.01** | $ 6.48 |
| Royalties | **1.48** | 1.30 | 1.38 | **1.39** | 1.33 |
| Production expense | **0.71** | 0.69 | 0.66 | **0.71** | 0.65 |
| Netback | **$ 5.14** | $ 4.69 | $ 4.60 | **$ 4.91** | $ 4.50 |
| **Barrels of oil equivalent** ($/boe, except daily production) | | | | | |
| Daily production, before royalties (boe/d) | **531,380** | 530,316 | 517,343 | **530,851** | 497,143 |
| Sales price (1) | **$ 43.05** | $ 39.94 | $ 38.20 | **$ 41.51** | $ 37.09 |
| Royalties | **5.85** | 5.42 | 5.55 | **5.64** | 5.30 |
| Production expense | **8.29** | 8.04 | 7.12 | **8.17** | 7.08 |
| Netback | **$ 28.91** | $ 26.48 | $ 25.53 | **$ 27.70** | $ 24.71 |

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

## BUSINESS ENVIRONMENT

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| WTI benchmark price (US$/bbl) | **$ 53.13** | $ 49.90 | $ 38.34 | **$ 51.53** | $ 36.75 |
| Dated Brent benchmark price (US$/bbl) | **$ 51.55** | $ 47.71 | $ 35.42 | **$ 49.64** | $ 33.70 |
| Differential to LLB blend (US$/bbl) | **$ 21.22** | $ 19.26 | $ 11.63 | **$ 20.25** | $ 10.77 |
| Condensate benchmark price (US$/bbl) | **$ 53.56** | $ 51.45 | $ 39.17 | **$ 52.51** | $ 37.58 |
| NYMEX benchmark price (US$/mmbtu) | **$ 6.80** | $ 6.31 | $ 5.97 | **$ 6.56** | $ 5.83 |
| AECO benchmark price (C$/GJ) | **$ 7.00** | $ 6.35 | $ 6.45 | **$ 6.67** | $ 6.35 |
| US / Canadian dollar average exchange rate (US$) | **0.8038** | 0.8152 | 0.7358 | **0.8094** | 0.7471 |

World crude oil prices continued to strengthen in the second quarter of 2005 due to tight world oil supplies caused by the growth in world-wide demand, particularly in the United States, China and India, as well as due to restricted refinery capacity in North America and continued political instability in various parts of the world. West Texas Intermediate ("WTI") averaged US$51.53 per bbl for the six months ended June 30, 2005, an increase of 40% compared to US$36.75 per bbl in the comparable period in 2004. In the second quarter of 2005, WTI averaged US$53.13 per bbl, up 39% from US$38.34 per bbl in the comparable period in 2004, and up 6% from US$49.90 per bbl in the first quarter of 2005.

The positive impact of higher WTI prices on the Company's crude oil production continues to be significantly offset by wider heavy crude oil differentials, which increased 88% to US$20.25 per bbl for the six months ended June 30, 2005 from US$10.77 in the comparable period in 2004. For the three months ended June 30, 2005, heavy crude oil differentials increased 82% compared to the second quarter of 2004 to average US$21.22 per bbl and increased 10% from the first quarter of 2005. Heavy crude oil differentials in 2005 were 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, also contributed to lower heavy crude oil price realizations. Compared to 2004, realized crude oil prices were also negatively impacted by the stronger Canadian dollar.

North America natural gas prices also remained strong due to concerns around supply and the impact of higher crude oil prices. NYMEX natural gas prices increased 13% to average US$6.56 per mmbtu for the six months ended June 30, 2005, up from US$5.83 per mmbtu in the comparable period in 2004. In the second quarter of 2005, NYMEX natural gas prices increased 14% to average US$6.80 per mmbtu, up from US$5.97 per mmbtu in the comparable period in 2004, and increased 8% from US$6.31 per mmbtu in the prior quarter. AECO natural gas prices increased 5% to average $6.67 per GJ for the six months ended June 30, 2005, up from $6.35 per GJ in the comparable period in 2004. AECO natural gas prices increased 9% to average $7.00 per GJ in the second quarter of 2005, up from $6.45 per GJ in the comparable period in 2004, and increased 10% from $6.35 per GJ in the prior quarter.

**PRODUCT PRICES**[1]

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** ($/bbl) | | | | | |
| North America | **$ 35.24** | $ 32.28 | $ 32.31 | **$ 33.79** | $ 31.54 |
| North Sea | **$ 64.81** | $ 59.56 | $ 49.22 | **$ 62.04** | $ 46.81 |
| Offshore West Africa | **$ 58.24** | $ 62.34 | $ 49.34 | **$ 59.95** | $ 45.63 |
| Company average | **$ 42.51** | $ 39.81 | $ 36.72 | **$ 41.17** | $ 35.49 |
| **Natural gas** ($/mcf) | | | | | |
| North America | **$ 7.38** | $ 6.73 | $ 6.78 | **$ 7.06** | $ 6.59 |
| North Sea | **$ 3.07** | $ 3.52 | $ 3.28 | **$ 3.33** | $ 4.17 |
| Offshore West Africa | **$ 6.88** | $ 7.67 | $ 5.18 | **$ 7.20** | $ 4.97 |
| Company average | **$ 7.33** | $ 6.68 | $ 6.64 | **$ 7.01** | $ 6.48 |
| **Company average** ($/boe) | **$ 43.05** | $ 39.94 | $ 38.20 | **$ 41.51** | $ 37.09 |
| **Percentage of revenue** (excluding midstream revenue) | | | | | |
| Crude oil and NGLs | **54%** | 54% | 51% | **54%** | 52% |
| Natural gas | **46%** | 46% | 49% | **46%** | 48% |

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

Realized crude oil prices increased 16% to average $41.17 per bbl for the six months ended June 30, 2005, up from $35.49 per bbl in the comparable period in 2004. For the second quarter 2005, realized crude prices increased 16% to average $42.51 per bbl, up from $36.72 per bbl in the comparable period in 2004 and up 7% from the first quarter of 2005. The increase in realized crude oil prices was primarily due to higher benchmark world crude oil prices.

The impact of the higher benchmark crude oil prices compared to 2004 was partially offset by the strengthening Canadian dollar, which increased 8% in relation the US dollar. An increase in the Canadian dollar results in lower revenue from the sale of the Company's production.

The Company's realized natural gas price increased 8% to average $7.01 per mcf for the six months ended June 30, 2005, up from $6.48 per mcf in the comparable period in 2004. The realized natural gas price increased 10% to average $7.33 per mcf in the second quarter of 2005, up 10% from $6.64 per mcf in the comparable period in 2004 and up 7% from $6.68 per mcf in the prior quarter. The increase in gas prices was due in large part to the increase in crude oil prices.

**North America**

North America realized crude oil prices increased 7% to average $33.79 per bbl for the six months ended June 30, 2005, up from $31.54 per bbl in the comparable period in 2004. Realized crude oil prices in the second quarter of 2005 averaged $35.24 per bbl, up from $32.31 per bbl in the comparable period in 2004. The increase in the realized crude oil price was due mainly to higher world crude oil prices, partially offset by wider heavy crude oil differentials and the strengthening Canadian dollar. Prices increased 9% in the second quarter of 2005 compared to the first quarter due to higher world oil prices offset by wider heavy crude oil differentials.

The Company continues to focus on its crude oil marketing strategy, which includes developing 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. During the second quarter, the Company contributed approximately 130 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 and has an API of 19-22 degrees. Volumes of the new blend are 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 oil 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 7% to average $7.06 per mcf for the six months ended June 30, 2005, up from $6.59 per mcf in the comparable period in 2004. The realized natural gas price in the second quarter of 2005 averaged $7.38 per mcf, up 9% from $6.78 per mcf in the comparable period in 2004 and up 10% from $6.73 per mcf in the prior quarter. The increases were due to fluctuations in the North America benchmark natural gas price in response to crude oil pricing.

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

| | **Q2 2005** | Q1 2005 | Q2 2004 |
|---|---|---|---|
| Wellhead Price (1) | | | |
| Light crude oil and NGLs (C$/bbl) | **$ 55.66** | $ 50.46 | $ 44.83 |
| Pelican Lake crude oil (C$/bbl) | **$ 34.24** | $ 31.74 | $ 31.90 |
| Primary heavy crude oil (C$/bbl) | **$ 28.42** | $ 25.46 | $ 28.22 |
| Thermal heavy crude oil (C$/bbl) | **$ 26.71** | $ 24.69 | $ 27.67 |
| Natural gas (C$/mcf) | **$ 7.38** | $ 6.73 | $ 6.78 |

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

**North Sea**

North Sea realized crude oil prices increased 33% to average $62.04 per bbl for the six months ended June 30, 2005, up from $46.81 per bbl in the comparable period in 2004, and increased 32% to average $64.81 per bbl in the second quarter of 2005, up from $49.22 per bbl in the comparable period in 2004. The increase in the realized crude oil price was due mainly to higher world benchmark crude oil prices and fluctuations in the Brent differential offset by the strengthening Canadian dollar. Prices increased 9% in the second quarter of 2005 compared to the first quarter due to higher world oil prices.

**Offshore West Africa**

Offshore West Africa realized crude oil prices increased 31% to average $59.95 per bbl for the six months ended June 30, 2005, up from $45.63 per bbl in the comparable period in 2004, and increased 18% to average $58.24 per bbl in the second quarter of 2005, up from $49.34 per bbl in the comparable period in 2004. The increase in the realized crude oil prices from the comparable periods in 2004 was due to higher world benchmark crude oil prices, offset by the strengthening Canadian dollar. The realized crude oil prices in the second quarter of 2005 decreased 7% from the previous quarter price of $62.34 per bbl due to the timing of liftings.

## DAILY PRODUCTION, before royalties

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** (bbl/d) | | | | | |
| North America | **215,693** | 209,125 | 203,741 | **212,427** | 197,946 |
| North Sea | **62,884** | 71,139 | 60,105 | **66,989** | 58,602 |
| Offshore West Africa | **10,487** | 7,539 | 11,552 | **9,021** | 11,794 |
| | **289,064** | 287,803 | 275,398 | **288,437** | 268,342 |
| **Natural gas** (mmcf/d) | | | | | |
| North America | **1,434** | 1,430 | 1,389 | **1,432** | 1,310 |
| North Sea | **17** | 23 | 55 | **20** | 54 |
| Offshore West Africa | **3** | 2 | 8 | **3** | 9 |
| | **1,454** | 1,455 | 1,452 | **1,455** | 1,373 |
| **Total barrel of oil equivalent (boe/d)** | **531,380** | 530,316 | 517,343 | **530,851** | 497,143 |
| **Product mix** | | | | | |
| Light crude oil and NGLs | **24%** | 25% | 23% | **24%** | 24% |
| Pelican Lake crude oil | **4%** | 3% | 4% | **4%** | 4% |
| Primary heavy crude oil | **17%** | 17% | 19% | **17%** | 19% |
| Thermal heavy crude oil | **9%** | 9% | 7% | **9%** | 7% |
| Natural gas | **46%** | 46% | 47% | **46%** | 46% |

## DAILY PRODUCTION, net of royalties

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** (bbl/d) | | | | | |
| North America | **189,137** | 179,472 | 177,643 | **184,331** | 172,840 |
| North Sea | **62,779** | 71,074 | 59,983 | **66,903** | 58,501 |
| Offshore West Africa | **10,160** | 7,310 | 11,197 | **8,743** | 11,433 |
| | **262,076** | 257,856 | 248,823 | **259,977** | 242,774 |
| **Natural gas** (mmcf/d) | | | | | |
| North America | **1,143** | 1,148 | 1,094 | **1,145** | 1,033 |
| North Sea | **17** | 23 | 54 | **20** | 54 |
| Offshore West Africa | **3** | 2 | 8 | **3** | 9 |
| | **1,163** | 1,173 | 1,156 | **1,168** | 1,096 |
| **Total barrel of oil equivalent (boe/d)** | **455,866** | 453,385 | 441,525 | **454,632** | 425,489 |

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.

Total crude oil and natural gas production averaged 530,851 boe/d for the six months ended June 30, 2005, an increase of 7% or 33,708 boe/d from the comparable period in 2004. Second quarter total production in 2005 reached record levels of 531,380 boe/d, an increase of 3% or 14,037 boe/d compared to the second quarter of 2004. The increase in production year over year was due to the Company's extensive capital expenditure program, which resulted in record levels of production, as well as accretive acquisitions completed in 2004.

Total crude oil and NGLs production for the six months ended June 30, 2005 increased 7% to 288,437 bbl/d from 268,342 bbl/d for the comparable period in 2004. In the second quarter of 2005, production was 289,064 bbl/d, an increase of 5% from 275,398 bbl/d in the second quarter of 2004. Crude oil and NGLs production in the second quarter of 2005 was in line with the Company's previously issued guidance of 280,000 to 303,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the six months ended June 30, 2005 increased 6% or 82 mmcf/d to average 1,455 mmcf/d compared to 1,373 mmcf/d for the comparable period in 2004. Natural gas production of 1,454 mmcf/d in the second quarter was negatively impacted by the early arrival of spring break-up and weather-related delays in North America. As a result of these weather-related factors, the Company's second quarter natural gas production was marginally under the Company's previously issued guidance of 1,478 to 1,521 mmcf/d.

The Company expects annual production levels in 2005 to average 1,432 to 1,474 mmcf/d of natural gas and 312 to 335 mbbl/d of crude oil and NGLs. Third quarter 2005 production guidance is 1,423 to 1,468 mmcf/d of natural gas and 322 to 344 mbbl/d of crude oil and NGLs.

**North America**

North America crude oil and NGLs production for the six months ended June 30, 2005 increased 7% or 14,481 bbl/d to average 212,427 bbl/d, up from 197,946 bbl/d in the comparable period in 2004. Production in the second quarter of 2005 increased 6% or 11,952 bbl/d to average 215,693 bbl/d, up from 203,741 bbl/d in the comparable period in 2004 and 3% higher than the first quarter 2005 production of 209,125 bbl/d. The increase in crude oil and NGLs production was mainly due to the timing of Primrose production cycles and the increased production as a result of the Pelican Lake waterflood project.

North America natural gas production for the six months ended June 30, 2005 increased 9% or 122 mmcf/d to average 1,432 mmcf/d, up from 1,310 mmcf/d in the comparable period in 2004. Natural gas production increased as a result of organic growth and accretive property acquisitions in 2004. In the second quarter of 2005, production increased 3% or 45 mmcf/d to average 1,434 mmcf/d, up from 1,389 mmcf/d in the comparable period in 2004. In the second quarter, natural gas production was negatively impacted by the early arrival of spring break-up and weather-related delays. In June 2005, wide areas of Alberta encountered significantly higher than normal precipitation levels resulting in extensive flooding and road closures throughout portions of the province. While the Company plans for a variety of weather-related contingencies, the impact of the unseasonably wet weather negatively impacted the Company's drilling, completion, tie-in and maintenance activities.

## North Sea

North Sea crude oil production for the six months ended June 30, 2005 was 66,989 bbl/d, an increase of 14% from 58,602 bbl/d in the comparable period in 2004. Crude oil production in the second quarter of 2005 increased 5% to 62,884 bbl/d, higher than production of 60,105 bbl/d in the comparable period in 2004, but 12% lower than first quarter 2005 production of 71,139 bbl/d. In the second quarter of 2005, a planned three-week maintenance shutdown of the Ninian South Platform reduced production from a portion of the Ninian Field, as well as the Lyell Field and Columbas Terraces, by approximately 22,000 bbl/d. Production in the second quarter was also negatively impacted by a production curtailment in the Murchison Field resulting from the shut-in of third party natural gas export facilities.

Natural gas production in the North Sea for the six months ended June 30, 2005 decreased 63% to average 20 mmcf/d, down from 54 mmcf/d in the comparable period in 2004. Natural gas production in the second quarter of 2005 decreased 69% from second quarter 2004 and 26% from the first quarter of 2005. 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 although the full production benefit has been constrained by facilities capacity.

## Offshore West Africa

Offshore West Africa crude oil production for the six months ended June 30, 2005 decreased 24% to 9,021 bbl/d, from 11,794 bbl/d in the comparable period in 2004. 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. Second quarter 2005 production of 10,487 bbl/d decreased 9% compared to production of 11,552 bbl/d in the second quarter of 2004, but increased by 39% from first quarter 2005 production of 7,539 bbl/d due to the first of the infill wells coming on stream in June 2005. Offshore West Africa production is expected to increase in the third quarter due to production from the 57.61% owned and operated Baobab Field located offshore Côte d'Ivoire. Production from the Baobab Field is anticipated to commence in early August 2005 at an expected rate of 25 mbbl/d net to the Company.

Natural gas production in Offshore West Africa for the six-month and three-month periods ended June 30, 2005 decreased from the comparable periods in 2004 due to the shut in of production as noted above.

## ROYALTIES

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** ($/bbl) | | | | | |
| North America | **$ 4.34** | $ 4.58 | $ 4.14 | **$ 4.45** | $ 4.00 |
| North Sea | **$ 0.11** | $ 0.05 | $ 0.10 | **$ 0.08** | $ 0.08 |
| Offshore West Africa | **$ 1.81** | $ 1.90 | $ 1.52 | **$ 1.85** | $ 1.39 |
| Company average | **$ 3.33** | $ 3.39 | $ 3.15 | **$ 3.36** | $ 3.03 |
| **Natural gas** ($/mcf) | | | | | |
| North America | **$ 1.50** | $ 1.33 | $ 1.44 | **$ 1.41** | $ 1.39 |
| North Sea | **$ -** | $ - | $ - | **$ -** | $ - |
| Offshore West Africa | **$ 0.21** | $ 0.23 | $ 0.16 | **$ 0.22** | $ 0.15 |
| Company average | **$ 1.48** | $ 1.30 | $ 1.38 | **$ 1.39** | $ 1.33 |
| **Company average** ($/boe) | **$ 5.85** | $ 5.42 | $ 5.55 | **$ 5.64** | $ 5.30 |
| **Percentage of revenue** (1) | | | | | |
| Crude oil and NGLs | **9%** | 9% | 9% | **9%** | 9% |
| Natural gas | **20%** | 20% | 21% | **20%** | 20% |
| Boe | **14%** | 14% | 15% | **14%** | 14% |

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

### North America

North America crude oil and NGLs royalties for the six and three months ended June 30, 2005 increased from the comparable periods in 2004 primarily due to higher benchmark crude oil prices. Second quarter 2005 crude oil and NGLs royalties decreased from the first quarter due to a higher proportion of the Company's production being composed of thermal and Pelican Lake crude oil, which are subject to lower royalty rates.

Natural gas royalties fluctuated from the comparable periods in 2004 and the prior quarter due to 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 remaining royalty 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 allocated to royalty expense and current income tax expense in accordance with the PSC.

## PRODUCTION EXPENSE

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| **Crude oil and NGLs** ($/bbl) | | | | | |
| North America | **$ 10.14** | $ 10.07 | $ 8.91 | **$ 10.11** | $ 8.78 |
| North Sea | **$ 17.41** | $ 14.91 | $ 13.84 | **$ 16.09** | $ 13.56 |
| Offshore West Africa | **$ 8.47** | $ 11.43 | $ 7.43 | **$ 9.70** | $ 7.26 |
| Company average | **$ 11.66** | $ 11.30 | $ 9.92 | **$ 11.48** | $ 9.75 |
| **Natural gas** ($/mcf) | | | | | |
| North America | **$ 0.68** | $ 0.66 | $ 0.60 | **$ 0.68** | $ 0.60 |
| North Sea | **$ 2.92** | $ 2.52 | $ 1.92 | **$ 2.70** | $ 1.78 |
| Offshore West Africa | **$ 1.37** | $ 1.25 | $ 1.38 | **$ 1.32** | $ 1.30 |
| Company average | **$ 0.71** | $ 0.69 | $ 0.66 | **$ 0.71** | $ 0.65 |
| **Company average** ($/boe) | **$ 8.29** | $ 8.04 | $ 7.12 | **$ 8.17** | $ 7.08 |

### North America

North America crude oil and NGLs production expense for the six and three months ended June 30, 2005 increased from the comparable periods in 2004. The increase was due to higher service costs as a result of increased industry-wide activity in reaction to higher commodity prices, the impact of the higher crude oil prices on fuel related expenses, and a larger portion of the Company's crude oil production being comprised of higher cost thermal crude oil. The increase in North America crude oil and NGLs production expense from the prior quarter was primarily due to increased production of higher cost thermal crude oil.

North America natural gas production expense per mcf for the six and three months ended June 30, 2005 increased from the comparable period in 2004. The increase was due to the service and commodity cost pressures noted above. North America natural gas production expense increased from the prior quarter due to third party gas plant maintenance shut downs in Northeast British Columbia and continued service cost pressures.

### North Sea

North Sea crude oil production expense varied on a per barrel basis from both the comparable periods 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 fluctuated on a per barrel basis from the comparable periods due to changes in production from the Espoir Field. Production expenses in the first six months of 2005 were impacted by the curtailment of production to facilitate the infill drilling program and the modifications to the FPSO to accommodate West Espoir production.

## MIDSTREAM

| ($ millions) | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Revenue | **$ 17** | $ 21 | $ 17 | **$ 38** | $ 33 |
| Production expense | **5** | 6 | 5 | **11** | 9 |
| Midstream cash flow | **12** | 15 | 12 | **27** | 24 |
| Depreciation | **2** | 2 | 1 | **4** | 3 |
| Segment earnings before taxes | **$ 10** | $ 13 | $ 11 | **$ 23** | $ 21 |

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% of the Company's heavy crude oil production was transported to 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 six months ended June 30, 2005 increased from the comparable period in 2004 due to increased third party revenue earned from the Pelican Lake Pipeline.

## DEPLETION, DEPRECIATION AND AMORTIZATION (1)

| | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Expense ($ millions) | **$ 482** | $ 472 | $ 425 | **$ 954** | $ 812 |
| $/boe | **$ 9.98** | $ 9.89 | $ 9.01 | **$ 9.93** | $ 8.96 |

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

Depletion, Depreciation and Amortization ("DD&A") for the six and three months ended June 30, 2005 increased in total and on a boe basis from the comparable periods in 2004 and the first quarter of 2005. 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 estimated future costs to develop the Company's proved undeveloped reserves.

## ASSET RETIREMENT OBLIGATION ACCRETION

| | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Expense ($ millions) | **$ 17** | $ 18 | $ 10 | **$ 35** | $ 21 |
| $/boe | **$ 0.36** | $ 0.38 | $ 0.22 | **$ 0.37** | $ 0.23 |

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

## ADMINISTRATION EXPENSE

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 (1) | **Jun 30 2005** | Jun 30 2004 (1) |
| Net expense ($ millions) | **$ 42** | $ 35 | $ 29 | **$ 77** | $ 57 |
| $/boe | **$ 0.85** | $ 0.74 | $ 0.63 | **$ 0.79** | $ 0.64 |

*(1) Restated to conform to current year presentation.*

Administration expense for the six and three months ended June 30, 2005 increased in total and on a boe basis from the comparable periods in 2004, as well as the first quarter of 2005, primarily due to higher staffing levels associated with the Company's expanding asset base and costs associated with the Company's Share Bonus Plan.

The Share Bonus Plan incorporates employee share ownership in the Company while reducing the granting of stock options and the dilution of current Shareholders. Under the plan, cash bonuses awarded based on Company and employee performance are 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 six months ended June 30, 2005, the Company recognized $13 million of compensation expense under the Share Bonus Plan (June 30, 2004 - $7 million).

## STOCK-BASED COMPENSATION

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 (1) | **Jun 30 2005** | Jun 30 2004 (1) |
| Stock option plan ($ millions) | **$ 215** | $ 184 | $ 50 | **$ 399** | $ 106 |
| $/boe | **$ 4.45** | $ 3.85 | $ 1.06 | **$ 4.15** | $ 1.18 |

*(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 recorded a $399 million ($271 million after tax) stock-based compensation expense for the six months ended June 30, 2005 in connection with the 73% appreciation in the Company's share price, and a $215 million ($146 million after tax) stock-based compensation expense as a result of the 30% appreciation in the Company's share price in the second quarter of 2005 (June 30, 2005 - C$44.40; March 31, 2005 - C$34.18; December 31, 2004 - C$25.63). As required by GAAP, the Company's outstanding stock options are carried at fair value based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the options exercised or surrendered in the period, with the net change recognized in stock-based compensation expense in the period. The stock-based compensation liability reflects the Company's potential cash liability should all the expensed options be surrendered for a cash payout at the market price on June 30, 2005. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the six months ended June 30, 2005, the Company paid $110 million for stock options surrendered for cash settlement (June 30, 2004 - $45 million).

## INTEREST EXPENSE

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| Interest expense, net ($ millions) | **$ 40** | $ 43 | $ 49 | **$ 83** | $ 94 |
| $/boe | **$ 0.82** | $ 0.91 | $ 1.03 | **$ 0.87** | $ 1.03 |
| Average effective interest rate | **5.2%** | 5.5% | 5.0% | **5.4%** | 5.3% |

Net interest expense decreased on a total and boe basis for the six and three months ended June 30, 2005 from the comparable periods in 2004 primarily due to the capitalization of construction period interest related to the Horizon Project in 2005 (three months ended June 30, 2005 – $14 million; three months ended March 31, 2005 - $11 million). Pre-capitalization interest increased over comparable periods in 2004 mainly due to higher overall debt levels.

## 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 did not qualify as hedges under the Guideline or were not designated as hedges ("non-designated hedges") were initially 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 price, 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 periodically 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.

Cross currency swap agreements are periodically used to manage 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.

## RISK MANAGEMENT

| ($ millions) | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| **Realized loss (gain)** | | | | | |
| Crude oil and NGLs financial instruments | **$ 94** | $ 105 | $ 108 | **$ 199** | $ 145 |
| Natural gas financial instruments | **2** | (10) | 2 | **(8)** | 2 |
| Interest rate swaps | **-** | (8) | (10) | **(8)** | (19) |
| | **$ 96** | $ 87 | $ 100 | **$ 183** | $ 128 |
| **Unrealized loss (gain)** | | | | | |
| Crude oil and NGLs financial instruments | **$ 168** | $ 907 | $ 61 | **$ 1,075** | $ 167 |
| Natural gas financial instruments | **(50)** | 86 | (3) | **36** | - |
| Interest rate swaps | **1** | 5 | 12 | **6** | 5 |
| | **$ 119** | $ 998 | $ 70 | **$ 1,117** | $ 172 |
| **Total** | **$ 215** | $ 1,085 | $ 170 | **$ 1,300** | $ 300 |

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 Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Crude oil and NGLs ($/bbl) | **$ 3.58** | $ 4.07 | $ 4.31 | **$ 3.82** | $ 2.96 |
| Natural gas ($/mcf) | **$ 0.02** | $ (0.08) | $ 0.01 | **$ (0.03)** | $ - |

The effect of the realized gain on non-designated interest rate swaps was to decrease the Company's interest expense as follows:

| ($ millions) | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Interest expense as per the financial statements | **$ 40** | $ 43 | $ 49 | **$ 83** | $ 94 |
| Realized risk management (gain) | **-** | (8) | (10) | **(8)** | (19) |
| | **$ 40** | $ 35 | $ 39 | **$ 75** | $ 75 |
| Average effective interest rate | **5.2%** | 4.5% | 4.0% | **4.8%** | 4.3% |

As effective as economic hedges are against reference commodity prices, a substantial portion of the crude oil related financial instruments entered into by the Company do not meet the requirements for hedge accounting under GAAP due to currency, product quality and location differentials (the “non-designated hedges”). The Company is required to mark-to-market these non-designated hedges based on prevailing forward commodity prices in effect at the end of each reporting period. Accordingly, unrealized risk management expense reflects, at June 30, 2005, the implied price differentials for the non-designated hedges for the remainder of 2005 and future years. Primarily due to the dramatic increase in crude oil forward pricing in 2005, the Company recorded a $1,117 million ($760 million after tax) unrealized loss on its risk management activities for the six months ended June 30, 2005, including a $119 million ($81 million after tax) unrealized loss for the three months ended June 30, 2005.

## FOREIGN EXCHANGE

| | Three Months Ended | | | Six Months Ended | |
|---|---|---|---|---|---|
| ($ millions) | **Jun 30 2005** | Mar 31 2005 | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| Realized foreign exchange gain | **$ (6)** | $ (12) | $ (10) | **$ (18)** | $ (14) |
| Unrealized foreign exchange loss | **16** | - | 36 | **16** | 83 |
| | **$ 10** | $ (12) | $ 26 | **$ (2)** | $ 69 |

The Company’s results are affected by the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority of the Company’s revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in lower revenue from the sale of the Company’s production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar will result in higher revenue from the sale of the Company’s production. The value of the Company’s US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar. Production expenses are also subject to fluctuations due to changes in the exchange rate of the UK pound sterling to the US dollar on North Sea operations.

The majority of the realized foreign exchange gain was 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 loss was related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt. The Canadian dollar ended the second quarter of 2005 at US$0.8159 compared to US$0.8308 at December 31, 2004 (March 31, 2005 - US$0.8267; June 30, 2004 - US$0.7460).

In order to mitigate a portion of the volatility associated with fluctuations in exchange rates, 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<br>**Jun 30 2005** | <br>Mar 31 2005 | <br>Jun 30 2004 | Six Months Ended<br>**Jun 30 2005** | <br>Jun 30 2004 |
|---|---|---|---|---|---|
| **Taxes other than income tax** | | | | | |
| Current | **$ 36** | $ 42 | $ 52 | **$ 78** | $ 87 |
| Deferred | **4** | - | (3) | **4** | 1 |
| | **$ 40** | $ 42 | $ 49 | **$ 82** | $ 88 |
| **Current income tax** | | | | | |
| North America – Current income tax | **$ 30** | $ 30 | $ 45 | **$ 60** | $ 82 |
| North America – Large corporations tax | **4** | 2 | 1 | **6** | 4 |
| North Sea | **28** | 39 | 14 | **67** | 37 |
| Offshore West Africa | **4** | 3 | 4 | **7** | 7 |
| | **$ 66** | $ 74 | $ 64 | **$ 140** | $ 130 |
| **Future income tax expense (recovery)** | **$ 62** | $ (241) | $ 82 | **$ (179)** | $ 63 |
| **Effective income tax rate** | **37.0%** | 28.3% | 36.1% | **15.8%** | 27.2% |

Taxes other than income tax includes current and deferred petroleum revenue tax ("PRT") and Canadian 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 decreased from the comparable periods as a result of higher capital expenditures and lower production from PRT paying fields.

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 North Sea current income tax expense for the six and three months ended June 30, 2005 increased from the comparable period in 2004 due mainly to higher realized product prices and increased production volumes.

In 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 phased elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid.

## CAPITAL EXPENDITURES

| ($ millions) | Three Months Ended Jun 30 2005 | Three Months Ended Mar 31 2005 | Three Months Ended Jun 30 2004 | Six Months Ended Jun 30 2005 | Six Months Ended Jun 30 2004 |
|---|---|---|---|---|---|
| **Expenditures on property, plant and equipment** | | | | | |
| Net property (dispositions) acquisitions [(1)] | **$ (341)** | $ 2 | $ 277 | **$ (339)** | $ 784 |
| Land acquisition and retention | **52** | 36 | 39 | **88** | 70 |
| Seismic evaluations | **20** | 41 | 11 | **61** | 43 |
| Well drilling, completion and equipping | **306** | 634 | 231 | **940** | 814 |
| Pipeline and production facilities | **283** | 432 | 166 | **715** | 446 |
| **Total net reserve replacement expenditures** | **320** | 1,145 | 724 | **1,465** | 2,157 |
| Horizon Oil Sands Project | **275** | 215 | 103 | **490** | 149 |
| Midstream | **-** | 4 | 3 | **4** | 3 |
| Abandonments | **7** | 4 | 6 | **11** | 13 |
| Head office | **7** | 4 | 8 | **11** | 15 |
| **Total net capital expenditures** | **$ 609** | $ 1,372 | $ 844 | **$ 1,981** | $ 2,337 |
| **By segment** | | | | | |
| North America | **$ 110** | $ 940 | $ 578 | **$ 1,050** | $ 1,875 |
| North Sea | **112** | 57 | 75 | **169** | 151 |
| Offshore West Africa | **97** | 144 | 71 | **241** | 131 |
| Other | **1** | 4 | - | **5** | - |
| Horizon Oil Sands Project | **275** | 215 | 103 | **490** | 149 |
| Midstream | **-** | 4 | 3 | **4** | 3 |
| Abandonments | **7** | 4 | 6 | **11** | 13 |
| Head office | **7** | 4 | 8 | **11** | 15 |
| Total | **$ 609** | $ 1,372 | $ 844 | **$ 1,981** | $ 2,337 |

*(1) Includes Business Combinations.*

The Company's strategy is focused on building a diversified asset base that is balanced between various products. In order to facilitate efficient operations, the Company focuses its activities into core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the 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 production costs.

Net capital expenditures in the six months ended June 30, 2005 were $1,981 million compared to $2,337 million in the comparable period in 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 927 net wells consisting of 398 natural gas wells, 258 crude oil wells, 199 stratigraphic test and service wells, and 72 wells that were dry compared to 971 net wells in the first six months of 2004. The Company achieved an overall success rate of 90%, 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.

Net capital expenditures in the second quarter of 2005 were $609 million compared to $844 million in the comparable period in 2004 and $1,372 million in the prior quarter. The decrease in net capital expenditures was primarily a result of the disposition of a large portion of the Company's overriding royalty interests throughout Western Canada and Ontario, combined with seasonally reduced drilling activity. In the second quarter the Company drilled a total of 236 net wells consisting of 60 natural gas wells, 149 crude oil wells, 11 stratigraphic test and service wells, and 16 wells that were dry compared to 132 net wells in the second quarter of 2004. The Company achieved an overall success rate of 93%, excluding stratigraphic test and service wells.

**North America**

North America accounted for approximately 79% of the total capital expenditures for the first six months of 2005 compared to approximately 88% in the comparable period in 2004.

During the first half of 2005, the Company drilled 454 net wells targeting natural gas, including 186 wells in Northeast British Columbia, 122 wells in the Northern Plains region, 79 wells in Northwest Alberta, and 67 wells in the Southern Plains region. The Company also drilled 267 net wells targeting crude oil during the first half of 2005. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 123 heavy crude oil wells, 39 Pelican Lake crude oil wells, 69 thermal crude oil wells, and 5 light crude oil wells were drilled. In the second quarter the Company drilled 60 net wells targeting natural gas and 146 net wells targeting crude oil.

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 plan.

In 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 commence a three-rig drilling program with a further 30 wells expected to be drilled in the second half of 2005. The Company plans to enhance the waterflood process by the use of a polymer flood. Facilities for the Pelican Lake polymer flood were installed in April and the pilot test has been initiated. The results of the pilot project are not expected for several months. If successful, a polymer flood could substantially increase the recovery over waterflood at Pelican Lake.

In the second quarter of 2005, the Company sold 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.

In the third quarter, the Company's drilling activity is expected to be comprised of 267 natural gas wells, including 104 shallow gas wells in Southern Alberta and 200 crude oil wells in the Northern Plains region, including 136 primary heavy crude oil wells.

**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 are targeted for 2012 following completion of Phase 3 of construction.

During the second quarter, the Horizon Project continued with detailed engineering and infrastructure development activity. In the second quarter, the temporary water and sewage treatment plants, the site clearing, the construction of the first of the plant camp sites, the airport road, and muskeg removal in preparation for overburden removal, were completed. Site grading and installation of deep underground facilities, such as electrical, natural gas, water and sewage are approximately 50% complete and on schedule, and overburden removal and dyke construction commenced. Further, the coker foundations area was turned over to the EPC contractor on schedule.

In addition to direct construction costs, the Company capitalized $25 million of construction period interest and $45 million of stock-based compensation costs during the six months ended June 30, 2005.

In the third quarter of 2005, the site aerodrome landing strip is expected to be completed and commissioned, the occupancy of the first of three on-site camps will occur, overburden removal is expected to be ramped up to 60,000 tonnes/d and the detailed engineering plan is expected to be over 60% complete. It is also anticipated that the plant site areas for Hydrotreating and Extraction foundation construction will be turned over to the contractor.

**North Sea**

In the second quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the second quarter 3.6 net wells were drilled.

In anticipation of the 2005 program of infill drilling, workovers and third party business on the T and B Blocks, the Company completed a major refurbishment of the Tiffany Platform drilling rig, which will facilitate a two well program. In the Thelma Field, the first of two wells is being drilled targeting unswept areas of the field, using a semi-submersible drilling unit.

In the third 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 is expected to result in lower combined operating costs from these fields and may ultimately extend field lives for both fields. During the third quarter, four net wells are expected to be completed.

**Offshore West Africa**

Offshore West Africa capital expenditures include the development of the 57.61% owned and operated Baobab Field, which was substantially complete at the end of the second quarter. Production from the Baobab Field is anticipated to commence in early August 2005 at an expected rate of 25 mbbl/d net to the Company.

At East Espoir, the first of four (2.3 net) wells scheduled for drilling in early 2005 came on stream. The drilling of these wells was 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.

The West Espoir drilling tower, which will facilitate development drilling of the reservoir, is under construction and progressing on time and within budget. First oil from West Espoir is expected in mid 2006, delivering 13 mboe/d when fully commissioned.

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 has entered into an agreement to dispose of its interest in the Block, subject to government approval.

**LIQUIDITY AND CAPITAL RESOURCES**

| ($ millions, except ratios) | **Jun 30 2005** | Mar 31 2005 | Dec 31 2004 | Jun 30 2004 |
|---|---|---|---|---|
| Working capital deficit [1] | **$ 1,340** | $ 1,288 | $ 652 | $ 444 |
| Long-term debt | **$ 3,649** | $ 3,831 | $ 3,538 | $ 3,716 |
| Shareholders' equity | | | | |
| Share capital | **$ 2,428** | $ 2,416 | $ 2,408 | $ 2,393 |
| Retained earnings | **4,655** | 4,468 | 4,922 | 4,090 |
| Foreign currency translation adjustment | **(4)** | (6) | (6) | - |
| Total | **$ 7,079** | $ 6,878 | $ 7,324 | $ 6,483 |
| Debt to cash flow [1] [2] | **0.9x** | 1.0x | 1.0x | 1.1x |
| Debt to EBITDA [1] [2] | **0.8x** | 0.9x | 0.9x | 1.0x |
| Debt to book capitalization [1] | **35.2%** | 36.9% | 33.8% | 36.4% |
| Debt to market capitalization [1] | **13.9%** | 18.0% | 21.4% | 25.7% |
| After tax return on average common shareholders' equity [2] | **9.9%** | 10.7% | 21.4% | 16.0% |
| After tax return on average capital employed [1] [2] | **7.5%** | 8.1% | 15.3% | 11.6% |

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

*(2) Based on trailing 12-month activity.*

At June 30, 2005, the working capital deficit was $1,340 million and included the current portion of other long-term liabilities of $1,178 million, comprised of stock-based compensation of $462 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $716 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 June 30, 2005.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Project. In the second quarter of 2005, strong operational results and commodity prices resulted in debt to book capitalization levels of approximately 35%. The Company believes it has 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 June 30, 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 authorized the expansion of the Company's economic hedging program to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow for its capital expenditures program through the Horizon Project construction period. This expanded program allows for the economic hedging of up to 75% of the near 12 months budgeted 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 through the use of derivative financial instruments. For the purpose of this program, the purchase of crude oil put options is in addition to the above parameters. As a result, approximately 70% of 2005 budgeted crude oil volumes and approximately 50% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 70% of 2005 budgeted natural gas volumes and approximately 50% 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 9 to the consolidated financial statements.

**Long-term debt**

As at June 30, 2005, the Company had in place unsecured bank credit facilities of $3,425 million, comprised of a $100 million operating demand facility, a $1,500 million, 5-year revolving credit facility maturing December 2009 and a two-tranche facility totaling $1,825 million. The first tranche of $1,000 million is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one year periods at the mutual agreement of the Company and the lenders.

At June 30, 2005, the Company had undrawn bank lines of credit of $3,192 million.

In May 2005, the company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Net proceeds from the sale of the notes were used to repay bank indebtedness. The sale of the notes was the first issuance under the short form Canadian base shelf prospectus dated August 1, 2003 which allows for the issuance of debt securities in an aggregate principal amount of up to C$1 billion.

In June 2005, the Company filed a short form shelf prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

**Share capital**

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. As at June 30, 2005, there were 536,885,000 common shares outstanding. As at July 29, 2005, the Company had 536,923,000 common shares outstanding.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 26,818,012 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 July 29, 2005, the Company had not purchased any common shares under the renewed Normal Course Issuer Bid.

In February 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.225 per common share. In May 2005, the Board of Directors approved an increase in the annual dividend paid by the Company to $0.24 per common share. The increase represents a 7% increase from the prior quarter and a 20% increase from the dividend paid on July 1, 2004, 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 Board of Directors increased the annual dividend paid by the Company to $0.20 per common share in 2004, up from the previous level of $0.15 per common share.

## 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 June 30, 2005:

| | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter |
|---|---|---|---|---|---|---|
| Natural gas transportation | $ 105 | $ 168 | $ 103 | $ 80 | $ 39 | $ 168 |
| Oil transportation and pipeline | $ 6 | $ 15 | $ 17 | $ 18 | $ 19 | $ 159 |
| FPSO operating lease | $ 54 | $ 53 | $ 53 | $ 53 | $ 53 | $ 199 |
| Baobab Project | $ 39 | $ - | $ - | $ - | $ - | $ - |
| Offshore drilling and other | $ 105 | $ 5 | $ - | $ - | $ - | $ - |
| Electricity | $ 14 | $ 39 | $ 41 | $ - | $ - | $ - |
| Office lease | $ 10 | $ 20 | $ 20 | $ 20 | $ 21 | $ 31 |
| Processing | $ 3 | $ 2 | $ - | $ - | $ - | $ - |
| Long-term debt (1) | $ 194 | $ - | $ 163 | $ 38 | $ 70 | $ 3,162 |

*(1) No debt repayments are reflected for the bank credit facilities due to the extendible nature of the facilities.*

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 Phase 1 of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008 respectively.

## 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

Beginning in 2005, in connection with the Board of Directors' approval of the Horizon Project, the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization ceases once construction is substantially complete. For the six months ended June 30, 2005, pre-tax interest of $25 million was capitalized to 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 second quarter of 2005. Each separate item in the sensitivity analysis shows the effect of an increase / decrease 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 | $ | 96 | $ | 0.18 | $ | 67 | $ | 0.13 |
| Including financial derivatives | $ | 1 - 21 | $ | 0.00 - 0.04 | $ | 0 - 4 | $ | 0.00 - 0.01 |
| Natural gas – AECO C$0.10/mcf [2] | | | | | | | | |
| Excluding financial derivatives | $ | 39 | $ | 0.07 | $ | 25 | $ | 0.05 |
| Including financial derivatives | $ | 38 | $ | 0.07 | $ | 24 | $ | 0.04 |
| **Volume changes** | | | | | | | | |
| Crude oil – 10,000 bbl/d | $ | 86 | $ | 0.16 | $ | 45 | $ | 0.08 |
| Natural gas – 10 mmcf/d | $ | 19 | $ | 0.04 | $ | 8 | $ | 0.01 |
| **Foreign currency rate change** | | | | | | | | |
| $0.01 change in C$ in relation to US$[2] | | | | | | | | |
| Excluding financial derivatives | $ | 69 - 71 | $ | 0.13 | $ | 25 - 26 | $ | 0.05 |
| Including financial derivatives | $ | 69 - 71 | $ | 0.13 | $ | 25 - 26 | $ | 0.05 |
| **Interest rate change - 1%** | $ | 8 | $ | 0.02 | $ | 8 | $ | 0.02 |

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

*(2) For details of financial instruments in place, see the consolidated financial statement note 9.*

## OTHER OPERATING HIGHLIGHTS

## NETBACK ANALYSIS

| ($/boe, except daily production) | Three Months Ended Jun 30 2005 | Mar 31 2005 | Jun 30 2004 | Six Months Ended Jun 30 2005 | Jun 30 2004 |
|---|---|---|---|---|---|
| Daily production, before royalties (boe/d) | **531,380** | 530,316 | 517,343 | **530,851** | 497,143 |
| Sales price [1] | **$ 43.05** | $ 39.94 | $ 38.20 | **$ 41.51** | $ 37.09 |
| Royalties | **5.85** | 5.42 | 5.55 | **5.64** | 5.30 |
| Production expense [2] | **8.29** | 8.04 | 7.12 | **8.17** | 7.08 |
| **Netback** | **28.91** | 26.48 | 25.53 | **27.70** | 24.71 |
| Midstream contribution [2] | **(0.25)** | (0.31) | (0.24) | **(0.28)** | (0.26) |
| Administration [3] | **0.85** | 0.74 | 0.63 | **0.79** | 0.64 |
| Interest, net | **0.82** | 0.91 | 1.03 | **0.87** | 1.03 |
| Realized risk management loss | **1.98** | 1.83 | 2.12 | **1.91** | 1.41 |
| Realized foreign exchange gain | **(0.14)** | (0.25) | (0.22) | **(0.19)** | (0.16) |
| Taxes other than income tax - current | **0.76** | 0.87 | 1.08 | **0.81** | 0.96 |
| Current income tax - North America | **0.62** | 0.63 | 0.95 | **0.62** | 0.91 |
| Current income tax - Large Corporations Tax | **0.09** | 0.05 | - | **0.07** | 0.04 |
| Current income tax - North Sea | **0.59** | 0.81 | 0.32 | **0.70** | 0.42 |
| Current income tax - Offshore West Africa | **0.08** | 0.06 | 0.08 | **0.07** | 0.08 |
| **Cash flow** | **$ 23.51** | $ 21.14 | $ 19.78 | **$ 22.33** | $ 19.64 |

*(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) | **Jun 30 2005** | Dec 31 2004 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash | **$ 31** | $ 28 |
| Accounts receivable and other | **1,704** | 1,138 |
| Current portion of other long-term assets (note 2) | **-** | 72 |
| | **1,735** | 1,238 |
| **Property, plant and equipment** (net) | **17,948** | 17,064 |
| **Other long-term assets** (note 2) | **114** | 108 |
| | **$ 19,797** | $ 18,410 |
| **LIABILITIES** | | |
| **Current liabilities** | | |
| Accounts payable | **$ 466** | $ 379 |
| Accrued liabilities | **1,237** | 1,057 |
| Current portion of long-term debt (note 3) | **194** | 194 |
| Current portion of other long-term liabilities (note 4) | **1,178** | 260 |
| | **3,075** | 1,890 |
| **Long-term debt** (note 3) | **3,649** | 3,538 |
| **Other long-term liabilities** (note 4) | **1,595** | 1,208 |
| **Future income tax** (note 5) | **4,399** | 4,450 |
| | **12,718** | 11,086 |
| **SHAREHOLDERS' EQUITY** | | |
| **Share capital** (note 6) | **2,428** | 2,408 |
| **Retained earnings** | **4,655** | 4,922 |
| **Foreign currency translation adjustment** (note 7) | **(4)** | (6) |
| | **7,079** | 7,324 |
| | **$ 19,797** | $ 18,410 |

*Commitments (note 10)*

**Consolidated statements of earnings**

| (millions of Canadian dollars, except per common share amounts, unaudited) | Three Months Ended Jun 30 2005 | Three Months Ended Jun 30 2004 | Six Months Ended Jun 30 2005 | Six Months Ended Jun 30 2004 |
|---|---|---|---|---|
| **Revenue** | **$ 2,164** | $ 1,865 | **$ 4,157** | $ 3,503 |
| Less: royalties | **(283)** | (262) | **(542)** | (480) |
| **Revenue, net of royalties** | **1,881** | 1,603 | **3,615** | 3,023 |
| **Expenses** | | | | |
| Production | **405** | 339 | **794** | 647 |
| Transportation | **66** | 50 | **133** | 116 |
| Depletion, depreciation and amortization | **484** | 426 | **958** | 815 |
| Asset retirement obligation accretion (note 4) | **17** | 10 | **35** | 21 |
| Administration | **42** | 29 | **77** | 57 |
| Stock-based compensation (note 4) | **215** | 50 | **399** | 106 |
| Interest, net | **40** | 49 | **83** | 94 |
| Risk management activities (note 9) | **215** | 170 | **1,300** | 300 |
| Foreign exchange loss (gain) | **10** | 26 | **(2)** | 69 |
| | **1,494** | 1,149 | **3,777** | 2,225 |
| **Earnings before taxes** | **387** | 454 | **(162)** | 798 |
| Taxes other than income tax | **40** | 49 | **82** | 88 |
| Current income tax (note 5) | **66** | 64 | **140** | 130 |
| Future income tax expense (recovery) (note 5) | **62** | 82 | **(179)** | 63 |
| **Net earnings (loss)** | **$ 219** | $ 259 | **$ (205)** | $ 517 |
| **Net earnings (loss) per common share** (note 8) | | | | |
| Basic | **$ 0.41** | $ 0.48 | **$ (0.38)** | $ 0.96 |
| Diluted | **$ 0.41** | $ 0.48 | **$ (0.38)** | $ 0.96 |

**Consolidated statements of retained earnings**

| (millions of Canadian dollars, unaudited) | Six Months Ended Jun 30 2005 | Six Months Ended Jun 30 2004 |
|---|---|---|
| **Balance – beginning of period** | **$ 4,922** | $ 3,650 |
| Net earnings (loss) | **(205)** | 517 |
| Dividends on common shares (note 6) | **(62)** | (54) |
| Purchase of common shares under Normal Course Issuer Bid (note 6) | **-** | (23) |
| **Balance – end of period** | **$ 4,655** | $ 4,090 |

**Consolidated statements of cash flows**

| (millions of Canadian dollars, unaudited) | Three Months Ended<br>**Jun 30 2005** | Three Months Ended<br>Jun 30 2004 | Six Months Ended<br>**Jun 30 2005** | Six Months Ended<br>Jun 30 2004 |
|---|---|---|---|---|
| **Operating activities** | | | | |
| Net earnings (loss) | **$ 219** | $ 259 | **$ (205)** | $ 517 |
| Non-cash items | | | | |
| Depletion, depreciation and amortization | **484** | 426 | **958** | 815 |
| Asset retirement obligation accretion | **17** | 10 | **35** | 21 |
| Stock-based compensation | **215** | 50 | **399** | 106 |
| Unrealized risk management activities | **119** | 70 | **1,117** | 172 |
| Unrealized foreign exchange loss | **16** | 36 | **16** | 83 |
| Deferred petroleum revenue tax (recovery) | **4** | (3) | **4** | 1 |
| Future income tax expense (recovery) | **62** | 82 | **(179)** | 63 |
| Deferred charges | **(33)** | 5 | **(38)** | (1) |
| Abandonment expenditures | **(7)** | (6) | **(11)** | (13) |
| Net change in non-cash working capital | **135** | (9) | **(87)** | (161) |
| | **1,231** | 920 | **2,009** | 1,603 |
| **Financing activities** | | | | |
| (Repayment) issue of bank credit facilities | **(614)** | 498 | **(341)** | 881 |
| Issue (repayment) of medium-term notes | **400** | (125) | **400** | (125) |
| Repayment of senior unsecured notes | **-** | (54) | **-** | (54) |
| Repayment of obligations under capital leases | **-** | (1) | **-** | (7) |
| Issue of common shares | **3** | 8 | **5** | 20 |
| Purchase of common shares | **-** | (30) | **-** | (30) |
| Dividends on common shares | **(30)** | (27) | **(57)** | (47) |
| Net change in non-cash working capital | **4** | 5 | **20** | (4) |
| | **(237)** | 274 | **27** | 634 |
| **Investing activities** | | | | |
| Expenditures on property, plant and equipment | **(950)** | (840) | **(2,318)** | (2,301) |
| Net proceeds on sale of property, plant and equipment | **348** | 2 | **348** | 4 |
| Net expenditures on property, plant and equipment | **(602)** | (838) | **(1,970)** | (2,297) |
| Investment in other assets | **(60)** | - | **(60)** | - |
| Net change in non-cash working capital | **(342)** | (366) | **(3)** | (28) |
| | **(1,004)** | (1,204) | **(2,033)** | (2,325) |
| **(Decrease) increase in cash** | **(10)** | (10) | **3** | (88) |
| **Cash – beginning of period** | **41** | 26 | **28** | 104 |
| **Cash – end of period** | **$ 31** | $ 16 | **$ 31** | $ 16 |
| **Interest paid** | **$ 47** | $ 47 | **$ 91** | $ 96 |
| **Taxes paid** | | | | |
| Taxes other than income tax | **$ 49** | $ 27 | **$ 159** | $ 71 |
| Current income tax | **$ 12** | $ 40 | **$ 123** | $ 63 |

**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

Beginning in 2005, in connection with the Board of Directors' approval of the Horizon Oil Sands Project ("Horizon Project"), the Company commenced capitalization of construction period interest based on costs incurred and the Company's cost of borrowing. Interest capitalization ceases once construction is substantially complete. For the six months ended June 30, 2005, pre-tax interest of $25 million was capitalized to the Horizon Project.

### Comparative figures

Comparative figures for the prior year have been restated to reflect the impact of the retroactive adoption of CICA Section 3860 "Financial Instruments – Presentation and Disclosure" effective December 31, 2004, on the Company's Preferred Securities.

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

## 2. OTHER LONG–TERM ASSETS

| | **Jun 30 2005** | Dec 31 2004 |
|---|---|---|
| Risk management (note 9) | **$ -** | $ 104 |
| Deferred charges and other | **114** | 76 |
| | **114** | 180 |
| Less: current portion | **-** | 72 |
| | **$ 114** | $ 108 |

## 3. LONG-TERM DEBT

| | Jun 30 2005 | Dec 31 2004 |
|---|---|---|
| Bank credit facilities | | |
| Bankers' acceptances | $ **216** | $ - |
| US dollar bankers' acceptances (2005 – US$ nil, 2004 – US$471 million) | **-** | 557 |
| Medium-term notes | **525** | 125 |
| Senior unsecured notes (2005 – US$218 million, 2004 – US$218 million) | **308** | 306 |
| Preferred securities (2005 – US$80 million, 2004 – US$80 million) | **98** | 96 |
| US dollar debt securities (2005 – US$2,200 million, 2004 – US$2,200 million) | **2,696** | 2,648 |
| | **3,843** | 3,732 |
| Less: current portion of long-term debt | **194** | 194 |
| | $ **3,649** | $ 3,538 |

**Bank credit facilities**

As at June 30, 2005, the Company had in place unsecured bank credit facilities of $3,425 million, comprised of a $100 million operating demand facility, a $1,500 million, 5-year revolving credit facility maturing December 2009 and a two-tranche facility totaling $1,825 million. The first tranche of $1,000 million is fully revolving for a period of three years to June 2008. The second tranche of $825 million is fully revolving for a period of five years to June 2010. Both tranches are extendible annually for one year periods at the mutual agreement of the Company and the lenders.

In addition to the outstanding debt, letters of credit aggregating $25 million were also outstanding at June 30, 2005.

**Medium-term notes**

In May 2005, the Company issued $400 million of debt securities maturing June 2015, bearing interest at 4.95%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

**US dollar debt securities**

In June 2005, the Company filed a short form shelf prospectus that allows for the issue of up to US$2 billion of debt securities in the United States until July 2007. If issued, these securities will bear interest as determined at the date of issuance.

## 4. OTHER LONG-TERM LIABILITIES

| | | **Jun 30 2005** | | Dec 31 2004 |
|---|---|---|---|---|
| Asset retirement obligation | **$** | **1,196** | $ | 1,119 |
| Stock-based compensation | | **642** | | 323 |
| Risk management (note 9) | | **919** | | - |
| Deferred revenue (note 9) | | **16** | | 26 |
| | | **2,773** | | 1,468 |
| Less: current portion | | **1,178** | | 260 |
| | **$** | **1,595** | $ | 1,208 |

**Asset retirement obligation**

At June 30, 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 approximately $3,120 million (December 31, 2004 - $3,060 million). These costs will be incurred over the lives of the operating assets and have been discounted using an average credit-adjusted risk free rate of 6.7%. A reconciliation of the discounted asset retirement obligation is as follows:

| | | **Six months ended Jun 30, 2005** | | Year ended Dec 31, 2004 |
|---|---|---|---|---|
| Asset retirement obligation | | | | |
| Balance – beginning of period | **$** | **1,119** | $ | 897 |
| Liabilities incurred | | **42** | | 339 |
| Liabilities settled | | **(11)** | | (32) |
| Asset retirement obligation accretion | | **35** | | 51 |
| Revision of estimates | | **(1)** | | (86) |
| Foreign exchange | | **12** | | (50) |
| Balance – end of period | **$** | **1,196** | $ | 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 vested options are surrendered for cash settlement.

| | **Six months ended Jun 30, 2005** | Year ended Dec 31, 2004 |
|---|---|---|
| Stock-based compensation | | |
| Balance – beginning of period | **$ 323** | $ 171 |
| Stock-based compensation provision | **399** | 249 |
| Current period payment for options surrendered | **(110)** | (80) |
| Transferred to common shares | **(15)** | (38) |
| Capitalized to Horizon Project | **45** | 21 |
| Balance – end of period | **642** | 323 |
| Less: current portion | **462** | 243 |
| | **$ 180** | $ 80 |

## 5. INCOME TAXES

The provision for income taxes is as follows:

| | Three Months Ended | | Six Months Ended | |
|---|---|---|---|---|
| | **Jun 30 2005** | Jun 30 2004 | **Jun 30 2005** | Jun 30 2004 |
| Current income tax expense | | | | |
| Current income tax – North America | **$ 30** | $ 45 | **$ 60** | $ 82 |
| Large corporations tax – North America | **4** | 1 | **6** | 4 |
| Current income tax – North Sea | **28** | 14 | **67** | 37 |
| Current income tax – Offshore West Africa | **4** | 4 | **7** | 7 |
| | **66** | 64 | **140** | 130 |
| Future income tax expense (recovery) | **62** | 82 | **(179)** | 63 |
| Income tax expense (recovery) | **$ 128** | $ 146 | **$ (39)** | $ 193 |

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** | Six months ended Jun 30, 2005 | | |
|---|---|---|---|
| **Common shares** | **Number of shares** (thousands) (1) | | **Amount** |
| Balance – beginning of period | **536,361** | **$** | **2,408** |
| Issued upon exercise of stock options | **524** | | **5** |
| Previously recognized liability on stock options exercised for common shares | **-** | | **15** |
| Balance – end of period | **536,885** | **$** | **2,428** |

*(1) Restated to reflect two-for-one common share split in May 2005.*

**Share split**

The Company's shareholders approved a subdivision or split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 5, 2005. All common share, stock option and per common share amounts have been restated to retroactively reflect the share split.

**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 26,818,012 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 June 30, 2005, the Company had not purchased any shares under its Normal Course Issuer Bid.

**Dividend policy**

The Company pays regular quarterly dividends in January, April, July, and October of each year.

On February 18, 2005, the Board of Directors set the regular 2005 quarterly dividend at $0.05625 per common share (2004 - $0.05 per common share). On May 5, 2005, the Board of Directors increased the regular quarterly dividend to $0.06 per common share effective with the dividend payable on July 1, 2005.

**Stock options**

| | Six Months Ended Jun 30, 2005 | | |
|---|---|---|---|
| | **Stock options** (thousands) (1) | | **Weighted average exercise price** (1) |
| Outstanding – beginning of period | **32,522** | **$** | **12.37** |
| Granted | **6,638** | **$** | **28.36** |
| Exercised for common shares | **(524)** | **$** | **9.60** |
| Surrendered for cash settlement | **(4,953)** | **$** | **10.20** |
| Forfeited | **(943)** | **$** | **16.31** |
| Outstanding – end of period | **32,740** | **$** | **15.87** |
| Exercisable – end of period | **8,835** | **$** | **10.77** |

*(1) Restated to reflect two-for-one common share split in May 2005.*

## 7. FOREIGN CURRENCY TRANSLATION ADJUSTMENT

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

| | | **Jun 30 2005** |
|---|---|---|
| Balance – beginning of period | **$** | **(6)** |
| Unrealized gain on translation of net investment | | **4** |
| Hedge of net investment with US dollar denominated debt (net of tax) | | **(2)** |
| Balance – end of period | **$** | **(4)** |

## 8. NET EARNINGS (LOSS) PER COMMON SHARE

| | Three Months Ended | | | | Six Months Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | | **Jun 30 2005** | | Jun 30 2004[1] | | **Jun 30 2005** | | Jun 30 2004[1] |
| Weighted average common shares outstanding (thousands) | | | | | | | | |
| Basic | | **536,689** | | 536,842 | | **536,597** | | 536,126 |
| Assumed settlement of preferred securities with common shares[2] | | **-** | | - | | **-** | | - |
| Diluted | | **536,689** | | 536,842 | | **536,597** | | 536,126 |
| Net earnings (loss) | **$** | **219** | $ | 259 | **$** | **(205)** | $ | 517 |
| Interest on preferred securities, net of tax[2] | | **-** | | - | | **-** | | - |
| Revaluation of preferred securities, net of tax[2] | | **-** | | - | | **-** | | - |
| Diluted net earnings (loss) | **$** | **219** | $ | 259 | **$** | **(205)** | $ | 517 |
| Net earnings (loss) per common share | | | | | | | | |
| Basic | **$** | **0.41** | $ | 0.48 | **$** | **(0.38)** | $ | 0.96 |
| Diluted | **$** | **0.41** | $ | 0.48 | **$** | **(0.38)** | $ | 0.96 |

*(1) Restated to reflect two-for-one common share split in May 2005.*

*(2) Preferred securities are not dilutive for the three months and six months ended June 30, 2005 and June 30, 2004.*

## 9. 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 net changes in fair value of non-designated financial instruments are recognized on the consolidated balance sheet and in net earnings.

| | Risk management mark-to-market | Deferred revenue |
|---|---|---|
| Balance – beginning of year | $ 104 | $ (26) |
| Purchase of put options | 94 | - |
| Net change in fair value of financial instruments outstanding as at June 30, 2005 | (1,117) | - |
| Amortization of deferred revenue | - | 10 |
| Balance – end of period | (919) | (16) |
| Less: current portion | (703) | (13) |
| | $ (216) | $ (3) |

Net unrealized mark-to-market losses for the three months ended June 30, 2005 were $119 million ($1,117 million for the six months ended June 30, 2005).

As at June 30, 2005, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $777 million (December 31, 2004 - net asset of $33 million).

The Company uses derivative financial instruments to manage its commodity price, 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 June 30, 2005:

| | Remaining term | Volume | Average price | Index |
|---|---|---|---|---|
| **Crude oil** | | | | |
| Oil price collars | 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 | Jul 2005 – Sep 2005 | 50,000 bbl/d | US$31.09 | WTI |
| | Oct 2005 – Dec 2005 | 50,000 bbl/d | US$29.81 | WTI |
| | Mar 2006 – Jul 2006 | 90,000 bbl/d | US$40.00 | WTI |
| | Jan 2007 – Dec 2007 | 100,000 bbl/d | US$28.00 | WTI |
| | Jan 2007 – Dec 2007 | 100,000 bbl/d | US$35.00 | WTI |
| Brent differential swaps | Jan 2006 – Dec 2006 | 25,000 bbl/d | US$1.29 | WTI/Dated Brent |
| | Jan 2007 – Dec 2007 | 50,000 bbl/d | US$1.34 | WTI/Dated Brent |

| | Remaining term | Volume | Average price | Index |
|---|---|---|---|---|
| **Natural gas** | | | | |
| AECO collars | 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 – Jun 2006 | 993,000 GJ/d | C$5.83 – C$8.06 | AECO |
| | Jul 2006 – Oct 2006 | 725,000 GJ/d | C$5.60 – C$ 7.59 | AECO |

| | Remaining term | | | Amount ($ millions) | Average exchange rate (US$/C$) |
|---|---|---|---|---|---|
| **Foreign currency** | | | | | |
| Currency collars | Jul 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 | Jul 2005 | – | Dec 2005 | US$125 | 1.55 | 7.69% | 7.30% |

| | Remaining term | | | Amount ($ millions) | Fixed rate | Floating rate |
|---|---|---|---|---|---|---|
| **Interest rate** | | | | | | |
| Swaps – fixed to floating | Jul 2005 | – | Jan 2007 | US$200 | 7.20% | LIBOR(1) + 2.23% |
| | Jul 2005 | – | Oct 2012 | US$350 | 5.45% | LIBOR(1) + 0.81% |
| | Jul 2005 | – | Dec 2014 | US$350 | 4.90% | LIBOR(1) + 0.38% |
| Swaps – floating to fixed | Jul 2005 | – | Mar 2007 | C$8 | 7.36% | CDOR(2) |

*(1) London Interbank Offered Rate.*

*(2) Canadian Deposit Overnight Rate.*

## 10. Commitments

The Company has committed to certain payments as follows:

| | 2005 | 2006 | 2007 | 2008 | 2009 | Thereafter |
|---|---|---|---|---|---|---|
| Natural gas transportation | $ 105 | $ 168 | $ 103 | $ 80 | $ 39 | $ 168 |
| Oil transportation and pipeline | $ 6 | $ 15 | $ 17 | $ 18 | $ 19 | $ 159 |
| FPSO operating lease | $ 54 | $ 53 | $ 53 | $ 53 | $ 53 | $ 199 |
| Baobab Project | $ 39 | $ - | $ - | $ - | $ - | $ - |
| Offshore drilling and other | $ 105 | $ 5 | $ - | $ - | $ - | $ - |
| Electricity | $ 14 | $ 39 | $ 41 | $ - | $ - | $ - |
| Office lease | $ 10 | $ 20 | $ 20 | $ 20 | $ 21 | $ 31 |
| Processing | $ 3 | $ 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 Phase 1 of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008 respectively.

## 11. SEGMENTED INFORMATION

| (millions of Canadian dollars, unaudited) | North America Three Months Ended Jun 30 | | North America Six Months Ended Jun 30 | | North Sea Three Months Ended Jun 30 | | North Sea Six Months Ended Jun 30 | | Offshore West Africa Three Months Ended Jun 30 | | Offshore West Africa Six Months Ended Jun 30 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 |
| **Segmented revenue** | **1,719** | 1,510 | **3,263** | 2,828 | **381** | 293 | **775** | 556 | **57** | 56 | **101** | 106 |
| Less: royalties | **(281)** | (260) | **(538)** | (476) | **-** | (1) | **(1)** | (1) | **(2)** | (1) | **(3)** | (3) |
| **Revenue, net of royalties** | **1,438** | 1,250 | **2,725** | 2,352 | **381** | 292 | **774** | 555 | **55** | 55 | **98** | 103 |
| **Segmented expenses** | | | | | | | | | | | | |
| Production | **288** | 241 | **563** | 460 | **104** | 85 | **205** | 162 | **9** | 9 | **17** | 18 |
| Transportation | **70** | 53 | **140** | 119 | **5** | 7 | **11** | 15 | **-** | - | **-** | - |
| Depletion, depreciation and amortization | **396** | 355 | **780** | 672 | **72** | 55 | **154** | 110 | **14** | 15 | **20** | 30 |
| Asset retirement obligation accretion | **7** | 7 | **16** | 14 | **10** | 3 | **19** | 7 | **-** | - | **-** | - |
| Realized risk management activities | **76** | 76 | **135** | 98 | **20** | 24 | **48** | 30 | **-** | - | **-** | - |
| **Total segmented expenses** | **837** | 732 | **1,634** | 1,363 | **211** | 174 | **437** | 324 | **23** | 24 | **37** | 48 |
| **Segmented earnings before the following** | **601** | 518 | **1,091** | 989 | **170** | 118 | **337** | 231 | **32** | 31 | **61** | 55 |
| **Non-segmented expenses** | | | | | | | | | | | | |
| Administration | | | | | | | | | | | | |
| Stock-based compensation | | | | | | | | | | | | |
| Interest | | | | | | | | | | | | |
| Unrealized risk management activities | | | | | | | | | | | | |
| Foreign exchange loss (gain) | | | | | | | | | | | | |
| **Total non-segmented expenses** | | | | | | | | | | | | |
| **Earnings (loss) before taxes** | | | | | | | | | | | | |
| Taxes other than income tax | | | | | | | | | | | | |
| Current income tax expense | | | | | | | | | | | | |
| Future income tax expense (recovery) | | | | | | | | | | | | |
| **Net earnings (loss)** | | | | | | | | | | | | |

| (millions of Canadian dollars, unaudited) | Midstream Three Months Ended Jun 30 | | Midstream Six Months Ended Jun 30 | | Other Three Months Ended Jun 30 | | Other Six Months Ended Jun 30 | |
|---|---|---|---|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 |
| **Segmented revenue** | **17** | 17 | **38** | 33 | **-** | - | **-** | - |
| Less: royalties | **-** | - | **-** | - | **-** | - | - | - |
| **Revenue, net of royalties** | **17** | 17 | **38** | 33 | - | - | - | - |
| **Segmented expenses** | | | | | | | | |
| Production | **5** | 5 | **11** | 9 | **-** | - | **-** | - |
| Transportation | **-** | - | **-** | - | **-** | - | **-** | - |
| Depletion, depreciation and amortization | **2** | 1 | **4** | 3 | **-** | - | **-** | - |
| Asset retirement obligation accretion | **-** | - | **-** | - | **-** | - | **-** | - |
| Realized risk management activities | **-** | - | **-** | - | **-** | - | **-** | - |
| **Total segmented expenses** | **7** | 6 | **15** | 12 | **-** | - | **-** | - |
| **Segmented earnings before the following** | **10** | 11 | **23** | 21 | - | - | - | - |
| **Non-segmented expenses** | | | | | | | | |
| Administration | | | | | | | | |
| Stock-based compensation | | | | | | | | |
| Interest | | | | | | | | |
| Unrealized risk management activities | | | | | | | | |
| Foreign exchange loss (gain) | | | | | | | | |
| **Total non-segmented expenses** | | | | | | | | |
| **Earnings (loss) before taxes** | | | | | | | | |
| Taxes other than income tax | | | | | | | | |
| Current income tax expense | | | | | | | | |
| Future income tax expense (recovery) | | | | | | | | |
| **Net earnings (loss)** | | | | | | | | |

| (millions of Canadian dollars, unaudited) | Inter-segment Elimination Three Months Ended Jun 30 | | Inter-segment Elimination Six Months Ended Jun 30 | | Total Three Months Ended Jun 30 | | Total Six Months Ended Jun 30 | |
|---|---|---|---|---|---|---|---|---|
| | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 | **2005** | 2004 |
| **Segmented revenue** | **(10)** | (11) | **(20)** | (20) | **2,164** | 1,865 | **4,157** | 3,503 |
| Less: royalties | **-** | - | **-** | - | **(283)** | (262) | **(542)** | (480) |
| **Revenue, net of royalties** | **(10)** | (11) | **(20)** | (20) | **1,881** | 1,603 | **3,615** | 3,023 |
| **Segmented expenses** | | | | | | | | |
| Production | **(1)** | (1) | **(2)** | (2) | **405** | 339 | **794** | 647 |
| Transportation | **(9)** | (10) | **(18)** | (18) | **66** | 50 | **133** | 116 |
| Depletion, depreciation and amortization | **-** | - | **-** | - | **484** | 426 | **958** | 815 |
| Asset retirement obligation accretion | **-** | - | **-** | - | **17** | 10 | **35** | 21 |
| Realized risk management activities | **-** | - | **-** | - | **96** | 100 | **183** | 128 |
| **Total segmented expenses** | **(10)** | (11) | **(20)** | (20) | **1,068** | 925 | **2,103** | 1,727 |
| **Segmented earnings before the following** | **-** | - | **-** | - | **813** | 678 | **1,512** | 1,296 |
| **Non-segmented expenses** | | | | | | | | |
| Administration | | | | | **42** | 29 | **77** | 57 |
| Stock-based compensation | | | | | **215** | 50 | **399** | 106 |
| Interest | | | | | **40** | 49 | **83** | 94 |
| Unrealized risk management activities | | | | | **119** | 70 | **1,117** | 172 |
| Foreign exchange loss (gain) | | | | | **10** | 26 | **(2)** | 69 |
| **Total non-segmented expenses** | | | | | **426** | 224 | **1,674** | 498 |
| **Earnings (loss) before taxes** | | | | | **387** | 454 | **(162)** | 798 |
| Taxes other than income tax | | | | | **40** | 49 | **82** | 88 |
| Current income tax expense | | | | | **66** | 64 | **140** | 130 |
| Future income tax expense (recovery) | | | | | **62** | 82 | **(179)** | 63 |
| **Net earnings (loss)** | | | | | **219** | 259 | **(205)** | 517 |

**Additions to property, plant and equipment**

| | Six months ended | |
|---|---|---|
| | **Jun 30 2005** | Jun 30 2004 |
| North America | **$ 882** | $ 2,047 |
| North Sea | **169** | 151 |
| Offshore West Africa | **272** | 131 |
| Other | **5** | 13 |
| Horizon Oil Sands Project | **490** | 149 |
| Midstream | **4** | 3 |
| Head office | **11** | 15 |
| | **$ 1,833** | $ 2,509 |

| | Property, plant and equipment | | Total assets | |
|---|---|---|---|---|
| | **Jun 30 2005** | Dec 31 2004 | **Jun 30 2005** | Dec 31 2004 |
| **Segmented assets** | | | | |
| North America | **$ 13,503** | $ 13,394 | **$ 14,891** | $ 14,428 |
| North Sea | **1,847** | 1,823 | **2,111** | 2,036 |
| Offshore West Africa | **1,153** | 901 | **1,222** | 914 |
| Other | **13** | 8 | **50** | 35 |
| Horizon Oil Sands Project | **1,162** | 672 | **1,209** | 672 |
| Midstream | **209** | 209 | **253** | 268 |
| Head office | **61** | 57 | **61** | 57 |
| | **$ 17,948** | $ 17,064 | **$ 19,797** | $ 18,410 |

## 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 June 30, 2005: | |
|---|---|
| Interest coverage (times) | |
| Net earnings(1) | 6.0x |
| Cash flow from operations(2) | 21.7x |

*(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.*

*(2) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.*

## 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 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 from operations, cash flow from operations per common 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 its performance. 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 & 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*

Kimberly I. McKay
*Treasurer*

Bruce E. McGrath
*Corporate Secretary*

**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

Ambassador Gordon D. Giffin

John G. Langille

Keith A.J. MacPhail

Allan P. Markin

Norman F. McIntyre

James S. Palmer, C.M., A.O.E., Q.C.

Eldon R. Smith, M.D.

David A. Tuer

**International Operations**

CNR International (U.K.) Limited

Martin Cole
*Vice-President & Managing Director*

**Investor Relations**

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