

Canadian Natural

Q3 **Nine Months Ended September 30, 2005**

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY CASH FLOW, 2006 BUDGET AND STRATEGIC INVESTMENT PLANS

In commenting on the third quarter 2005 results and the Company's defined growth plan, Canadian Natural's Chairman, Allan Markin, stated "Canadian Natural is in an enviable position. We have a strong asset base and a strong core of technical, operational and financial expertise to unlock the value of these assets as well as the Balance Sheet capacity to finance it. Today, we are announcing our long-term plan to unlock the potential of our vast oil sands assets and in so doing will create significant value for our shareholders. Our plan calls for the evaluation of the combination of Horizon Project Phases 2 and 3 into one combined Project as well as the planned expansion of a further 265,000 bbl/d of Synthetic Crude Oil production from Phases 4 and 5 of the Horizon Project. In addition, we have articulated plans to review the feasibility of constructing a 125,000 bbl/d heavy oil upgrader near our in-situ oil sands developments. This provides additional markets for our heavy oil production and captures a significant portion of the heavy oil value chain. Execution of this strategic plan will allow Canadian Natural to develop its vast oil sands in-situ potential with plans to bring on an incremental 240,000 bbl/d of thermal heavy oil over the next 10-15 years. Management's vision is to build a balanced, sustainable lower-risk exploitation based enterprise and we believe that no other Company has the asset base to define such a plan with such clarity. Just as importantly, we have the skill set and team to deliver on that plan."

Steve Laut, President and Chief Operating Officer of Canadian Natural added, "We have a clearly defined, low-risk plan and the key to value creation is the successful low cost execution of that plan, on a quarter by quarter, year by year basis. The third quarter was a tremendous example of that. In Canada, our natural gas production increased by 5% over the previous year despite weather challenges. Our thermal crude oil sands development as well as our Pelican Lake waterflood continue to exceed expectations. Internationally, we brought Baobab on-stream in only 4.5 years after initial discovery while our infill program at East Espoir has resulted in 27% production gains on that Field. Our world-class Horizon Project continues on time and on budget and the $400 million of engineering work completed prior to construction is paying dividends, allowing us to contain costs and capitalize on construction opportunities going forward. For 2006 we look for continued production growth in each of our segments and 10% overall, all achieved while maintaining strong financial discipline. Of particular note, in 2006 our West Espoir Field located offshore Cote d'Ivoire will come on stream and we will commence development of the newly acquired Olowi Field located offshore Gabon. In Canada, we expect our Primrose in-situ oil sands production volumes to continue to rise to approximately 80 mbbl/d. Construction expenditures on the Horizon Oil Sands Project are expected to reach $2.6 billion in 2006, with construction progress expected to reach 63% completion by December 2006. All of this is to be financed primarily through cash flow. Expected year end debt to book capitalization at the end of 2006 is targeted at approximately 31%. We are definitely capitalizing on our opportunities while maintaining financial and operational discipline."

HIGHLIGHTS

($ millions, except as noted)	Quarterly Results Q3/05	Q2/05	Q3/04	Nine Month Results 2005	2004
Net earnings (loss)	**$ 151**	$ 219	$ 311	**$ (54)**	$ 828
per common share, basic [(1)]	**$ 0.28**	$ 0.41	$ 0.58	**$ (0.10)**	$ 1.54
Adjusted net earnings from operations [(2)]	**$ 593**	$ 460	$ 381	**$ 1,433**	$ 1,084
per common share, basic [(1)]	**$ 1.10**	$ 0.86	$ 0.71	**$ 2.67**	$ 2.02
Cash flow from operations [(3)]	**$ 1,386**	$ 1,136	$ 1,041	**$ 3,531**	$ 2,819
per common share, basic [(1)]	**$ 2.58**	$ 2.12	$ 1.94	**$ 6.58**	$ 5.26
Capital expenditures, net of dispositions	**$ 1,272**	$ 609	$ 875	**$ 3,253**	$ 3,212
Debt to book capitalization [(4)]	**32%**	35%	33%	**32%**	33%
Daily production, before royalties					
Natural gas (mmcf/d)	**1,423**	1,454	1,396	**1,444**	1,381
Crude oil and NGLs (mbbl/d)	**334.7**	289.1	297.3	**304.0**	278.1
Equivalent production (mboe/d)	**571.9**	531.4	529.9	**544.7**	508.2

(1) 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 Q3/05 of approximately $1.4 billion, a 33% improvement over Q3/04 and a 22% improvement over Q2/05.
- Strong quarterly adjusted net earnings from operations of $593 million, representing a 56% increase over Q3/04 and a 29% increase over Q2/05.
- Record quarterly production volumes, 8% higher than Q3/04 and Q2/05. Quarterly natural gas production represents 42% of equivalent production and 50% of North American equivalent production. North American natural gas volumes increased 5% over Q3/04 levels.
- Third quarter net earnings of $151 million included charges of:
  - $430 million after tax for the unrealized mark-to-market of the Company's non-designated commodity hedge position, effectively recognizing commodity strip price strength at September 30 for hedged production for the remainder of 2005 and future years into current results.
  - $135 million after tax for revaluation of stock option liability to reflect stock price appreciation during the quarter.
- Successful third quarter drilling program of 414 net wells, excluding stratigraphic test and service wells, with a 95% success ratio, reflecting Canadian Natural's strong, predictable, low risk asset base.
- Continued strong undeveloped conventional land base in Canada of 11.2 million net acres – a key asset in today's highly competitive industry.
- Facilities for the offshore Baobab Field in Côte d'Ivoire were commissioned in early August with initial production levels of 30 mbbl/d net to Canadian Natural.

- Record production in the North Sea during Q3/05 at 76.5 mboe/d, up 16% from Q2/05, following successful completion of maintenance work.
- In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon, West Africa with development plans to proceed in 2006.
- Horizon Oil Sands Project ("Horizon Project") remained on budget and on schedule with site preparation and construction work completed as planned.
- During the quarter, a pipeline transportation agreement was signed, which will facilitate a dedicated, expandable pipeline to Canadian Natural which will allow Horizon Project Synthetic Crude Oil ("SCO") to reach the pipeline hub at Edmonton, Alberta.
- Strong balance sheet maintained with debt to book capitalization of 32% and debt to EBITDA of 0.7 times.
- Repurchased 300,000 common shares under its Normal Course Issuer Bid.
- Determined 2006 Budget initiatives as follows:
  - 2006 capital expenditures of $6.8 billion. This includes $2.8 billion in North America reflecting the drilling of 1,139 natural gas wells and 722 crude oil wells as well as $0.9 billion internationally to effect exploitation and development work in both the North Sea and Offshore West Africa. Approximately $2.6 billion will be expended on construction of the Horizon Project with a further $128 million spent on pre-engineering of future Phases 2 and 3 of the Horizon Project.
  - Capital spending on the Horizon Project in the amount of $400 million has been accelerated into 2006 from 2007 following completion of significant site work in 2005. This allows for early turnover for construction of several key areas and better balancing of demands on a limited labour force.
  - Equivalent production targets of 580 - 632 mboe/d before royalties, an increase of 10% over midpoint 2005 guidance. Natural gas production is targeted to increase by 5%, while crude oil production will increase by 13%.
  - Utilizing a 2006 planning price deck of US$55/bbl WTI and C$8.75/GJ AECO, cash flow is estimated to reach $5.4 billion to $5.6 billion. These parameters would result in a debt to book capitalization ratio of approximately 31% and debt to EBITDA of 0.9 times at the end of 2006.
- Developed and commenced the implementation of long-term strategic investment plans for the Company's Canadian crude oil assets, as follows:
  - Review the economic and engineering merits of combining Phase 2 and Phase 3 expansions of the Horizon Project into one combined Phase targeted to commence production in 2011. While not changing overall expected capital costs, this combination will provide enhanced overall economics as it allows full synergies and production to be achieved at an earlier date.
  - Commission engineering review on the feasibility of installation of gasification into Horizon Project Phases 1 to 3 in 2013. This technology would be built into Horizon Project Phase 4 and 5 expansions.
  - Commencement of scoping of Phase 4 of Horizon Project to include the addition of 125 mbbl/d of new SCO production targeted to commence in 2014 with Phase 5 adding a further 140 mbbl/d of SCO targeted in 2017.
  - Commence and complete engineering design and execution strategy to build a 100% owned and operated upgrader ("Canadian Natural Upgrader") for the Company's in-situ oil sands assets in the Cold Lake to Athabasca region. This 125 mbbl/d Upgrader would produce light, sweet SCO and would be targeted for commissioning in 2012, with the ability to expand to 175 mbbl/d of light, sweet SCO in later years.
  - The initiation of a program targeted at the development of Canadian Natural's vast in-situ oil sands opportunities as feedstock for the Canadian Natural Upgrader. Over the next 13 -15 years, the Company will target to add over 240 mbbl/d of additional thermal oil sands production to be brought on stream from an estimated undeveloped resource potential of over 3 billion barrels.
  - Upon completion of these strategic investment plans, the Company targets total oil sands in-situ production could reach 300 mbbl/d, 175 mbbl/d of which will be upgraded to SCO and the remainder of which will be marketed as heavier crude oil blends. This is in addition to 497 mbbl/d of SCO currently targeted to be marketed from the Horizon Project and related expansions.

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 production costs.

Activity by core region

	Net undeveloped land as at Sep 30, 2005 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2005 (net wells)
Canadian conventional		
Northeast British Columbia	**2,071**	**206**
Northwest Alberta	**1,646**	**121**
Northern Plains	**6,698**	**626**
Southern Plains	**652**	**223**
Southeast Saskatchewan	**90**	**45**
	11,157	**1,221**
Horizon Oil Sands Project	**116**	**122**
United Kingdom North Sea	**413**	**9**
Offshore West Africa	**886**	**5**
	12,572	**1,357**

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
		2005		2004
	Gross	**Net**	Gross	Net
Crude oil	**490**	**437**	249	221
Natural gas	**723**	**611**	607	537
Dry	**106**	**94**	88	82
Subtotal	**1,319**	**1,142**	944	840
Stratigraphic test / service wells	**217**	**215**	277	276
Total	**1,536**	**1,357**	1,221	1,116
Success rate (excluding stratigraphic test / service wells)		**92%**		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.

Total Company equivalent production

	Q3/05		Q2/05		Q3/04	
	mboe/d	**%**	mboe/d	%	mboe/d	%
Natural gas	**237.2**	**42**	242.3	46	232.7	44
Light crude oil and NGLs	**153.6**	**27**	126.3	24	128.8	24
Pelican Lake crude oil	**24.8**	**4**	20.0	4	21.0	4
Primary heavy crude oil	**93.6**	**16**	92.2	17	96.3	18
Thermal heavy crude oil	**62.7**	**11**	50.6	9	51.1	10
Total	**571.9**	**100**	531.4	100	529.9	100

North American natural gas

	Quarterly Results			Nine Month Results	
	Q3/05	Q2/05	Q3/04	**2005**	2004
Natural gas production (mmcf/d)	**1,400**	1,434	1,336	**1,421**	1,319
Net wells targeting natural gas	**226**	68	99	**680**	611
Net successful wells drilled	**213**	60	93	**611**	537
Success rate	**94%**	88%	94%	**90%**	88%

- Q3/05 natural gas production represented a 5% increase over the previous year and a lower than normal summer production decline from Q2, despite much wetter than normal weather. This summer decline occurs each year due to the winter-oriented drilling program in Canada. In 2005 this decline only approached 2.4% versus 3.8% in 2004 and 2003. This reflects an active drilling program and the more balanced approach that the Company has taken in 2005 in an effort to control drilling cost escalation.
- High success rates reflect Canadian Natural’s low-risk exploitation approach and high quality land base. The Q3/05 drilling program included an active Southern Plains program and was highlighted by the drilling of 81 shallow natural gas and 31 coal bed methane wells. These types of wells, although highly economic, do not add enough productive capacity to offset normal basin declines. In addition, a combined 101 natural gas wells were successfully drilled throughout the Company’s four natural gas regions.
- Canadian Natural growth rates for 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 and the strength of the Company’s natural gas assets. Q4/05 drilling activity is expected to total 346 net wells. This program combined with current North American production levels of approximately 1,412 mmcf/d, will result in fourth quarter production of 1,396 mmcf/d to 1,436 mmcf/d.
- 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 third quarter was 129% more than that of the previous year. Canadian Natural continues to believe that a balanced drilling approach will yield better cost control and in fact is essential in a high cost environment, as peak drill rig utilization is reduced at high demand periods.

North American crude oil and NGLs

	Quarterly Results			Nine Month Results	
	Q3/05	Q2/05	Q3/04	**2005**	2004
Crude oil and NGLs production (mbbl/d)	**231**	216	214	**219**	203
Net wells targeting crude oil	**184**	153	37	**451**	219
Net successful wells drilled	**175**	146	33	**427**	212
Success rate	**95%**	95%	89%	**95%**	96%

- Q3/05 crude oil drilling activity was concentrated in the Northern Plains with 112 net wells targeting heavy crude oil. Wetter than normal weather impeded the primary heavy crude oil drilling program with only 112 of an expected 150 wells being drilled. These wells, along with 29 wells budgeted for Q4/05, will be reinventoried for future years.
- The Primrose Field development continued with the drilling of 19 new wells in Q3/05. Production from the pads at Primrose is subject to the cycling of steam injection and crude oil production. Due to normal cycling activities as well as the addition of new well pads, average thermal crude oil production levels in Q3/05 were 62 mbbl/d or 23% higher than Q3/04. Volumes are expected to decrease in Q4/05 for another steam cycle. Overall, the new Primrose pads continue to produce at rates approximately 30% better than expected while project development continues on plan.
- The Primrose North expansion plans continue on schedule and on budget. Steam injection into the first pad has commenced with first crude oil production expected in January 2006 ramping to 30 mbbl/d by Q3/2006.
- The Pelican Lake waterflood expansion continues to exceed expectations and, coupled with the drilling of 21 additional producing wells, resulted in production levels increasing by 5 mbbl/d or 24% over Q2/05.
- In Southeast Saskatchewan, 16 wells were drilled on the Pierson light oil play, resulting in 575 bbl/d of new light oil production. This better than expected result will create additional exploitation inventory as this knowledge is leveraged on a regional basis.

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			Nine Month Results	
	Q3/05	Q2/05	Q3/04	**2005**	2004
Total crude oil production (mbbl/d)					
North Sea	**74**	63	72	**69**	63
Offshore West Africa	**30**	10	11	**16**	12
Total natural gas production (mmcf/d)					
North Sea	**18**	17	53	**19**	54
Offshore West Africa	**5**	3	7	**4**	8
Net wells targeting crude oil	**4.3**	4.2	3.1	**11.4**	10.1
Net successful wells drilled	**4.3**	3.4	3.1	**10.0**	9.1
Success rate	**100%**	81%	100%	**88%**	90%

North Sea

- Canadian Natural continues to execute its exploitation plans in the North Sea. Q3/05 production achieved all time record levels following completion of scheduled maintenance. However, production remained below expectations due to continued production curtailments resulting from third party natural gas export restrictions at the Murchison Platform and a loss of productivity from certain wells in the Columba Terraces as the lift capacity performance of the long reach wells was less than anticipated with the expected onset of water production.
- Commencing late in Q3/05, all production from the Kyle Field was processed through the Banff Floating Production Storage and Offtake vessel ("FPSO"). The existing Kyle FPSO was released in September 2005. The consolidation of these production facilities has resulted in lower combined operating costs from these fields and may ultimately extend field lives for both fields.
- During Q3/05, 2.5 net wells were drilled with an additional 3.6 net wells drilling at quarter end.
- On the T-Block, at Toni a three subsea well intervention program resulted in an uplift of about 3 mbbl/d. In addition, on Thelma the first of two wells is currently drilling, targeting unswept areas of the field.
- At Balmoral, agreement was reached to tie in the third party Brenda facilities, which will result in lower per-unit operating costs when that field commences production in 2006/7.
- Construction of the subsea water injection pump at Columba E commenced during the quarter. This will be tied into 2 additional subsea water injection wells that will be drilled in 2006.
- Plans for the further development of Lyell progressed, comprising the drilling of 4 new wells and workovers at 2 existing wells in 2006/7.
- Canadian Natural continues to utilize its mature basin expertise and will continue to evaluate accretive acquisition opportunities with exploitation upside potential.

Offshore West Africa

- First production from the 57.61% owned and operated Baobab Field, located offshore Côte d'Ivoire, commenced on August 9, 2005 at approximately 48 mbbl/d (approximately 30 mbbl/d net to Canadian Natural) from 4 wells. Upon completion of drilling of further wells in early 2006, production levels will achieve 35 mbbl/d net to Canadian Natural. 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 was brought on stream in 4.5 years and within the Company's budgeted costs in a highly competitive environment.
- Net production at East Espoir increased by 3 mbbl/d from Q2/05 levels and averaged 14 mboe/d during Q3/05 following the commencement of production from the infill drilling program. The infill drilling program consists of four wells, with two wells now completed and the remaining to be completed in 2006.
- The construction of the West Espoir drilling tower, which will facilitate development drilling of this reservoir, was completed during the quarter and is currently being installed on location. The project continues on time and on budget with first crude oil production expected in mid-2006, ramping up to 13 mboe/d when fully developed.
- In October 2005, Canadian Natural completed the acquisition of the permit to develop the Olowi Field, offshore Gabon, West Africa. The acquired permit (No. G4-187) comprises a 100% operating interest in the production sharing agreement for the block containing the Olowi Field, located about 20 kilometres from the Gabonese coast and in 30 metres water depth. Olowi has been delineated by the drilling of 15 wells on the block and contains approximately 500 million barrels of 34º API light crude oil in place. The oil reservoir is overlain by a large gas cap with about 1 trillion cubic feet of gas in place. The development of the crude oil reserves will commence in late 2006 with first production targeted for late 2008 at a rate of 20 mbbl/d.

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 company is currently evaluating the opportunity to combine Phase 2 and 3 for a joint operational date of 2011.
- All major milestones required before winter have been completed despite excessive rainfall in the third quarter which slowed site preparation work. Completion of these milestones is a key component in achieving critical path success.
- 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.
- Capital costs for Phase 1 of the Horizon Project are estimated at, including a contingency fund of $700 million, $6.8 billion with $1.4 billion to be incurred in 2005, and $2.6 billion in 2006. Total targeted capital costs for all three phases of the development are $10.8 billion.
- The quarterly update for the project is as follows:

Project status summary	**Sep 30, 2005**		Dec 31, 2005
	Actual	Plan	Plan
Work progress (cumulative)	**13%**	14%	16%
Capital spending (cumulative)	**12%**	13%	20%

Accomplished during the third quarter

Detailed Engineering

- All project areas are fully staffed and overall detailed engineering is on schedule to plan.
- 3-D design models are 30% complete and interface confirmation is underway.

Procurement

- Total procurement progress is at C$3.65 billion in awarded contracts and purchase orders, with a further C$700 million in the tender stage.
- Key common service awards were made, notably for air charter services, which has facilitated the Company's fly-in / fly -out strategy for skilled labour.

Modularization

- Module fabrication and assembly continues for the main piperack, and module deliveries to the site commenced in September. Deliveries will continue to achieve an inventory of over 80 modules on site to allow efficient installation to begin in the first half of 2006.

Construction

- On-site safety performance improved for the 8th month in a row, as Canadian Natural continues to stress safety awareness.
- Occupancy of the first (of three) on-site camp, built to accommodate up to 1,500 construction personnel was completed.
- Completion and commissioning of the site Aerodrome with 737-size aircraft now landing regularly.

- Coker foundations are 80% complete and are on track for Coker installation in spring 2006.
- Mine overburden removal is 15% ahead of plan, with 3.5 million banked cubic meters of overburden removed to date. Overburden removal operations averaged over 80,000 tonnes/day in September.
- Plant site areas for Hydrotreating, Froth Treatment, Sulphur, Hydrogen, Main Piperack and Extraction have been turned over for construction in order to begin foundation work.
- Completed and operating the first project systems; Potable Water, Communications, Sanitary Sewer, Power Distribution, River Intake and Natural Gas.

Q4/2005 milestones

- Expect the total awarded contracts and purchase orders to exceed C$4 billion.
- Begin earthwork for raw water and recycle water pond systems.
- Shop maintenance building ready for occupancy and start of the gas-oil and diesel reactors assembly.
- Turnover of Fire Hall and Emergency Medical Services buildings to respective units.
- Substantial completion of the second (of three) on-site camps built to accommodate an additional 1,500 construction personnel.

MARKETING

	Quarterly Results			Nine Months Results	
	Q3/05	Q2/05	Q3/04	**2005**	2004
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl)	**$ 63.17**	$ 53.13	$ 43.85	**$ 55.45**	$ 39.13
Lloyd Blend Heavy oil differential from WTI (%)	**30%**	40%	29%	**36%**	29%
US/Canada average exchange rate	**0.8325**	0.8038	0.7650	**0.8170**	0.7530
Corporate average pricing before risk management (C$/bbl)	**$ 57.35**	$ 42.51	$ 43.50	**$ 47.04**	$ 38.37
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 7.73**	$ 7.00	$ 6.32	**$ 7.03**	$ 6.34
Corporate average pricing before risk management (C$/mcf)	**$ 8.61**	$ 7.33	$ 6.24	**$ 7.53**	$ 6.40

- Heavy oil differentials returned to the long term average of 30% following a period of higher than normal differentials experienced throughout the first half of 2005. The Company's current expectations for average differentials over the next twelve months are approximately 32%, with Q4/05 expected to be in the high-30% range due to normal seasonality.
- During the third 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 Nederland. This pipeline is currently being filled with first deliveries expected to commence in early 2006.

FINANCIAL REVIEW

- Canadian Natural has prepared its financial position to profitably grow its conventional crude oil and natural gas operations over the next several years and 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 570 mboe/d, comprised of approximately 42% natural gas and 58% crude oil - with 95% of production located in G7 countries with stable and secure economies.
  - Financial stability and liquidity – $3.4 billion of bank credit facilities. In the aggregate, Canadian Natural had $3.36 billion of unused bank lines available at September 30, 2005.
  - Strong balance sheet – with a debt to book capitalization ratio of 32%, debt to cash flow of 0.8x, debt to EBITDA of 0.7x and shareholders' equity of $7.2 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.
- 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 support the Company's cash flow for its capital expenditure program throughout 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 75% of fourth quarter expected 2005 crude oil volumes and approximately 55% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 70% of fourth quarter expected 2005 natural gas volumes and approximately 55% of expected 2006 natural gas volumes have similarly been 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 substantial portion of the 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 September 30, 2005, the implied price differentials for the non-designated hedges for the remainder of 2005 and future years. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $1,750 million ($1,190 million after tax) unrealized loss on its risk management activities for the nine months ended September 30, 2005, including a $633 million ($430 million after tax) unrealized loss for the three months ended September 30, 2005. This unrealized loss does not reduce the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its objective of securing funding for its capital projects and does not intend to alter its current strategy of obtaining price certainty for its crude oil and natural gas production.
- In August 2005 the Company updated its short form shelf prospectus, allowing for the issue of up to $2 billion of medium term note securities in Canada until September 2007.
- During Q3/05, Canadian Natural also utilized its Normal Course Issuer Bid program administered through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") in order to repurchase and cancel 300,000 common shares for a total cost of C$16 million (C$53.27 per common share). As at October 28, 2005 a total of 450,000 common shares had been repurchased under these facilities.

Q4/05 OUTLOOK

The Company currently expects 2005 production levels before royalties to average 1,436 to 1,448 mmcf/d of natural gas and 308 to 316 mbbl/d of crude oil and NGLs. Q4/05 production guidance before royalties is 1,411 to 1,460 mmcf/d of natural gas and 323 to 352 mbbl/d of crude oil and NGLs.

Detailed guidance on production levels and operating costs can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/. Commodity hedge information is regularly updated and may similarly be found at http://www.cnrl.com/investor_info/corporate_guidance/hedging.html.

2006 BUDGET

- Crude oil and NGLs production target of 335 - 373 mbbl/d before royalties representing a midpoint increase of 13% from the midpoint of 2005 annual guidance.
- Natural gas production target of 1,468 – 1,551 mmcf/d before royalties representing a midpoint increase of 5% from the midpoint of 2005 annual guidance.
- Equivalent production target of 580 - 632 mboe/d before royalties representing a midpoint increase of 10% from the midpoint of 2005 annual guidance.
- Cash flow estimate of $5.4 billion - $5.6 billion ($10.05 – $10.43 per common share) based upon a forecast average West Texas Intermediate oil price of US$55/bbl, a NYMEX natural gas price of US$8.75/mmbtu and an exchange rate of C$1.00 = US$0.85.
- Continued strong balance sheet management with targeted debt to book capitalization at the end of 2006 of approximately 31% and debt to EBITDA of 0.9 times.
- The budgeted capital expenditures in 2006 are currently expected to be as follows:

($ millions)	2005 Revised	**2006 Budget**
Conventional oil and gas		
North America natural gas	$ 1,590	**$ 1,741**
North America crude oil and NGLs	1,166	**1,097**
North Sea	400	**733**
Offshore West Africa	410	**187**
Property acquisitions, dispositions and midstream	(246)	**63**
	3,320	**3,821**
Horizon Oil Sands Project Phase 1 construction	1,372	**2,561**
Capitalized interest and other items	158	**222**
Horizon Oil Sands Project Phase 2/3 engineering	-	**128**
Canadian Natural Upgrader engineering	-	**30**
	$ 4,850	**$ 6,762**

The above capital expenditure budget incorporates the following levels of drilling activity:

Drilling activity (number of net wells)	2005 Forecast	**2006 Budget**
Targeting natural gas	1,025	**1,139**
Targeting crude oil	627	**722**
Stratigraphic test / service wells	266	**398**
Total	1,918	**2,259**

Drilling Program

The 2006 North American natural gas program represents another strong program as shown below.

(number of net wells)	2005 Forecast	**2006 Budget**
Northeast British Columbia	229	**262**
Northwest Alberta	165	**147**
Northern Plains	179	**251**
Southern Plains	452	**479**
Total	1,025	**1,139**

The 2006 North America crude oil drilling program is highlighted by continued development of Primrose North and another strong conventional heavy program and consists of:

(number of net wells)	2005 Forecast	**2006 Budget**
Conventional heavy crude oil	321	**344**
Thermal oil sands	110	**92**
Light crude oil	93	**111**
Pelican Lake crude oil	85	**150**
Total	609	**697**

Horizon Oil Sands Project

- The 2006 base capital budget of $2,561 million for the Horizon Oil Sands Project will facilitate completions and setting of the main piperack modules as well as the setting of the coker drums and reactors. In addition, the Ore Preparation Plant construction will commence in the pit and extraction separation cells will be erected.

- This budget represents an acceleration of spending into 2006, which allows Canadian Natural to capitalize on the opportunities created by having significant work completed during 2005. This serves to modify labour requirements timing and ease the execution of the project. Capital for Phase 1 remains at $6.8 billion, and the allocation of the additional $400 million from 2007 to 2006 will result in construction progress at the end of 2006 increasing from 55% to 63%.

- Expenditure of $128 million to initiate engineering work, order certain long lead items and review the economic and engineering merits of combining Phase 2 and Phase 3 expansions into one combined Phase targeted to commence production in 2011. While not changing overall expected capital costs, this combination will provide enhanced overall economics as it allows full synergies and production to be achieved at an earlier date.

International

North Sea

- In 2006, 12 net platform wells will be drilled on Ninian, Murchison and Tiffany.

- Canadian Natural has contracted two semi-submersible drill rigs to execute near pool exploration and development programs. A total of 6 producer wells will be drilled at Columba E, Lyell, Toni, and Thelma.

- Canadian Natural will allocate $129 million in 2006 for the further subsea development of the Lyell Field. Lyell is estimated to contain resource potential of approximately 45 million barrels and is expected to commence production in late 2006 and ramp up to 14 mbbl/d net to Canadian Natural in 2007.

- Canadian Natural will allocate $104 million to the waterflood development of the Columba E Terrace in 2006. This will include the injection of raw sea water into the formation. Additional resource potential to Canadian Natural is estimated at 8 to 10 million barrels.

Offshore West Africa

- Canadian Natural will allocate $79 million to complete infill drilling at East Espoir and the development of the West Espoir Field in 2006.

- Two additional wells will be completed at Baobab in 2006, allowing production to ramp to 35 mbbl/d net to the Company.

- The field development plan for the Olowi Field offshore Gabon will be submitted prior to the end of 2005 and $32 million will be expended on development of the Field in 2006.

STRATEGIC INVESTMENT PLANS FOR CANADIAN CRUDE OIL ASSETS

- Canadian Natural believes that its multi-year defined growth plan provides transparency of strategy as well as benchmarks against which to judge Management performance. This Plan is comprised of a 5-year lower risk exploitation based execution strategy and is now augmented by a longer term exploitation strategy for the Company's vast heavy oil resources and plans to capture a significant portion of the heavy oil value chain.

- 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 (which has been aggressively and successfully pursued by the Company – now blending 130 mbbl/d);

  – working with pipeline companies to gain access to new North American and world-wide markets (as evidenced by the recent participation in the Coriscana pipeline reversal to the US Gulf Coast); and,

  – working to advance expansions of heavy crude oil conversion capacity of refineries in the Midwest United States.

- Based upon the success of its three-tiered heavy oil marketing approach as well as the balance sheet strength provided by current commodity prices, Canadian Natural is intent upon advancing its heavy oil developments and unlocking the huge value potential of this asset base.

- Canadian Natural is the second largest producer of oil from in-situ operations and has extensive operating experience on thermal oil sands developments through its successful Primrose Field cyclic steam stimulation ("CSS") as well as Steam Assisted Gravity Drainage ("SAGD") experience on the Tangleflags, Wolf Lake and Burnt Lake Fields. In addition, Canadian Natural maintains very extensive land holdings that are amenable to in-situ development. In particular, at Primrose, Gregoire Lake, Kirby Lake, Birch Mountain, Ipiatuk and Leismer, the Company estimates that over 3 billion barrels of bitumen resources are recoverable.

- Central to this expansion will be the construction of the Canadian Natural Upgrader, which will be capable of processing heavy crude oil throughout the Cold Lake – South Athabasca oil sands fairway. Ownership of such a facility will enable Canadian Natural to capture a larger portion of the value chain while expanding production of a high demand product. Initially planned at 125 mbbl/d of SCO for 2012, the Canadian Natural Upgrader project will lever the expertise garnered during the design of the Horizon Project upgrader. The approach for the project will also follow Canadian Natural's disciplined approach with a scoping study and design basis memorandum to be commenced in 2006 and ensuring extensive front end engineering is completed prior to construction.

- Canadian Natural has identified 8 phases of production expansions of 30 mbbl/d each on the previously mentioned in-situ fields, which may be brought on over the next 13 - 15 years. This 240,000 bbl/d of new in-situ oil sands production is in addition to the 120,000 bbl/d long-term development plan currently articulated for the Primrose Field.

- At the Horizon Project, Canadian Natural has decided to review the economic and engineering merits of combining Phase 2 and Phase 3 expansions into one combined Phase targeted to commence production in 2011. While not changing overall expected capital costs, this combination will provide enhanced overall economics as it allows full synergies and production to be achieved at an earlier date. This change will also facilitate the Company's labour strategies in that it provides a smoother transition from Phase 1, keeps an experienced force on-site and optimizes the projected demand for construction labour.

- Scoping of Phase 4 of Horizon Project to include the addition of 125 mbbl/d of new SCO production targeted to commence in 2015 with Phase 5 adding a further 140 mbbl/d targeted to commence in 2017.

- In both its oil sands mining and in-situ production, the generation of heat is a critical element to success. Engineering design will be completed to install gasification into Horizon Project Phases 1 to 3 in 2013. This technology would be built into Horizon Project Phase 4 and 5 expansions as well as the Canadian Natural Upgrader.

- In announcing this expanded Plan, Canadian Natural Management was cognizant of the need to maintain discipline while capitalizing on available opportunities. Each of these developments:

  - levers existing experience,
  - provides natural migration of professional engineering and project management skills,
  - provides natural migration of construction workers,
  - is financially supported through anticipated cash flow of the Company,
  - unlocks Canadian Natural's vast heavy crude oil resource value potential,
  - captures a major portion of the value chain in the heavy crude oil business, and
  - controls operating costs in oil sands mining and in-situ operations.

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 nine months ended September 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 to net earnings 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 nine months ended September 30, 2005 in relation to the comparable periods in 2004 and the second quarter in 2005. The accompanying tables form an integral part of this MD&A. This MD&A is dated October 28, 2005.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004[1]	**Sep 30 2005**	Sep 30 2004[1]
Revenue, before royalties	**$ 2,918**	$ 2,164	$ 2,075	**$ 7,075**	$ 5,578
Net earnings (loss)	**$ 151**	$ 219	$ 311	**$ (54)**	$ 828
Per common share – basic	**$ 0.28**	$ 0.41	$ 0.58	**$ (0.10)**	$ 1.54
– diluted	**$ 0.28**	$ 0.41	$ 0.57	**$ (0.10)**	$ 1.53
Adjusted net earnings from operations[2]	**$ 593**	$ 460	$ 381	**$ 1,433**	$ 1,084
Per common share – basic	**$ 1.10**	$ 0.86	$ 0.71	**$ 2.67**	$ 2.02
– diluted	**$ 1.10**	$ 0.86	$ 0.70	**$ 2.67**	$ 2.01
Cash flow from operations[3]	**$ 1,386**	$ 1,136	$ 1,041	**$ 3,531**	$ 2,819
Per common share – basic	**$ 2.58**	$ 2.12	$ 1.94	**$ 6.58**	$ 5.26
– diluted	**$ 2.57**	$ 2.12	$ 1.93	**$ 6.58**	$ 5.22
Capital expenditures, net of dispositions	**$ 1,272**	$ 609	$ 875	**$ 3,253**	$ 3,212

(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			*Nine Months Ended*	
($ millions)	***Sep 30 2005***	*Jun 30 2005*	*Sep 30 2004*	***Sep 30 2005***	*Sep 30 2004*
Net earnings (loss) as reported	***$ 151***	*$ 219*	*$ 311*	***$ (54)***	*$ 828*
Unrealized foreign exchange (gain) loss, net of tax [a]	***(104)***	*14*	*(80)*	***(90)***	*(14)*
Unrealized risk management loss, net of tax [b]	***430***	*81*	*70*	***1,190***	*185*
Stock-based compensation, net of tax [c]	***135***	*146*	*80*	***406***	*151*
Effect of statutory tax rate changes on future income tax liabilities [d]	***(19)***	*-*	*-*	***(19)***	*(66)*
Adjusted net earnings from operations	***$ 593***	*$ 460*	*$ 381*	***$ 1,433***	*$ 1,084*

(a) Unrealized foreign exchange gains and losses result from the translation of U.S. dollar denominated 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 recorded 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 prices of the underlying items hedged, primarily crude oil and natural gas.

(c) The Company's employee stock option plan provides for a cash payment option. Accordingly, 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 third quarter of 2005, the province of British Columbia introduced legislation to reduce its corporate income tax rate by 1.5%. During the first quarter of 2004, the province of Alberta introduced legislation to reduce its corporate income tax rate by 1%.

(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. Cash flow from operations may not be comparable to similar measures presented by other companies.*

	Three Months Ended			Nine Months Ended	
($ millions)	***Sep 30 2005***	*Jun 30 2005*	*Sep 30 2004*	***Sep 30 2005***	*Sep 30 2004*
Net earnings (loss)	***$ 151***	*$ 219*	*$ 311*	***$ (54)***	*$ 828*
Non-cash items:					
Depletion, depreciation and amortization	***505***	*484*	*453*	***1,463***	*1,268*
Asset retirement obligation accretion	***18***	*17*	*14*	***53***	*35*
Stock-based compensation	***199***	*215*	*119*	***598***	*225*
Unrealized risk management activities	***633***	*119*	*105*	***1,750***	*277*
Unrealized foreign exchange (gain) loss	***(124)***	*16*	*(100)*	***(108)***	*(17)*
Deferred petroleum revenue tax (recovery)	***(14)***	*4*	*(14)*	***(10)***	*(13)*
Future income tax expense (recovery)	***18***	*62*	*153*	***(161)***	*216*
Cash flow from operations	***$ 1,386***	*$ 1,136*	*$ 1,041*	***$ 3,531***	*$ 2,819*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the nine months ended September 30, 2005, the Company recorded a loss of $54 million compared to net earnings of $828 million for the same period in 2004. The loss for the first nine months of 2005 includes unrealized after-tax expenses of $1,487 million related to the Company's risk management activities and stock-based compensation plans, net of foreign exchange gains and the effect of statutory tax rate changes, compared to $256 million in the comparable period in 2004. Excluding the effects of these items, adjusted net earnings from operations increased 32% to $1,433 million from $1,084 million in the comparable period in 2004 due to continuing strong crude oil and natural gas prices as well as record levels of total production on a boe basis.

For the third quarter 2005, the Company reported net earnings of $151 million compared to net earnings of $219 million in the second quarter 2005 and net earnings of $311 million for the third quarter 2004. Net earnings in the third quarter of 2005 included unrealized after-tax expenses of $442 million related to risk management activities and stock-based compensation plans, net of foreign exchange gains and the effect of statutory tax rate changes, compared to $70 million in the third quarter of 2004 and $241 million in the second quarter of 2005. Excluding these items, adjusted net earnings from operations in the third quarter of 2005 increased by 56% to $593 million from $381 million in the comparable period in 2004, and increased 29% from $460 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 support the Company's cash flow for its capital expenditure program throughout 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 75% of fourth quarter expected 2005 crude oil volumes and approximately 55% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 70% of fourth quarter expected 2005 natural gas volumes and approximately 55% of expected 2006 natural gas volumes have similarly been hedged through the use of collars. Details of the Company's risk management 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 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 September 30, 2005, the implied price differentials for the non-designated hedges for the remainder of 2005 and future years. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $1,750 million ($1,190 million after tax) unrealized loss on its risk management activities for the nine months ended September 30, 2005, including a $633 million ($430 million after tax) unrealized loss for the three months ended September 30, 2005. This unrealized loss does not reduce the Company's current cash flow or its ability to finance ongoing capital programs. The Company continues to believe that its risk management program meets its 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 $598 million ($406 million after tax) stock-based compensation expense for the nine months ended September 30, 2005 in connection with the 105% appreciation in the Company's share price during the period, and a $199 million ($135 million after tax) stock-based compensation expense as a result of the 18% appreciation in the Company's share price in the third quarter of 2005 (September 30, 2005 - C$52.50; June 30, 2005 - C$44.40; December 31, 2004 - C$25.63). As required by GAAP, the Company records a liability for anticipated cash payments to settle its outstanding employee stock options, 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 each quarter 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 September 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 nine months ended September 30, 2005 increased 25% to a record level of $3,531 million from $2,819 million for the comparable period in 2004. Record cash flow from operations in the third quarter of 2005 increased to $1,386 million, up 33% from $1,041 million for the third quarter of 2004 and up 22% from $1,136 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 544,688 boe/d for the nine months ended September 30, 2005, up 7% from 508,157 boe/d in the comparable period in 2004. Production for the third quarter of 2005 increased 8% to 571,911 boe/d from 529,946 boe/d in the third quarter of 2004 and increased 8% from 2005 second quarter production of 531,380.

OPERATING HIGHLIGHTS

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs ($/bbl, except daily production) [(2)]					
Daily production, before royalties (bbl/d)	**334,724**	289,064	297,262	**304,036**	278,052
Sales price [(1)]	**$ 57.35**	$ 42.51	$ 43.50	**$ 47.04**	$ 38.37
Royalties	**5.11**	3.33	3.59	**4.00**	3.23
Production expense	**11.48**	11.66	10.21	**11.48**	9.92
Netback	**$ 40.76**	$ 27.52	$ 29.70	**$ 31.56**	$ 25.22
Natural gas ($/mcf, except daily production) [(2)]					
Daily production, before royalties (mmcf/d)	**1,423**	1,454	1,396	**1,444**	1,381
Sales price [(1)]	**$ 8.61**	$ 7.33	$ 6.24	**$ 7.53**	$ 6.40
Royalties	**1.93**	1.48	1.39	**1.57**	1.35
Production expense	**0.76**	0.71	0.71	**0.72**	0.67
Netback	**$ 5.92**	$ 5.14	$ 4.14	**$ 5.24**	$ 4.38
Barrels of oil equivalent ($/boe, except daily production) [(2)]					
Daily production, before royalties (boe/d)	**571,911**	531,380	529,946	**544,688**	508,157
Sales price [(1)]	**$ 54.87**	$ 43.05	$ 40.92	**$ 46.17**	$ 38.44
Royalties	**7.84**	5.85	5.68	**6.40**	5.43
Production expense	**8.56**	8.29	7.59	**8.31**	7.26
Netback	**$ 38.47**	$ 28.91	$ 27.65	**$ 31.46**	$ 25.75

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

(2) All tabular amounts except for daily production figures are based on daily sales volumes.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
WTI benchmark price (US$/bbl)	**$ 63.17**	$ 53.13	$ 43.85	**$ 55.45**	$ 39.13
Dated Brent benchmark price (US$/bbl)	**$ 61.47**	$ 51.55	$ 41.58	**$ 53.63**	$ 36.35
Differential to LLB blend (US$/bbl)	**$ 18.73**	$ 21.22	$ 12.55	**$ 19.74**	$ 11.37
Condensate benchmark price (US$/bbl)	**$ 63.40**	$ 53.56	$ 42.66	**$ 56.18**	$ 39.28
NYMEX benchmark price (US$/mmbtu)	**$ 8.23**	$ 6.80	$ 5.85	**$ 7.12**	$ 5.84
AECO benchmark price (C$/GJ)	**$ 7.73**	$ 7.00	$ 6.32	**$ 7.03**	$ 6.34
US / Canadian dollar average exchange rate (US$)	**0.8325**	0.8038	0.7650	**0.8170**	0.7530

World crude oil prices continued to strengthen in the third quarter of 2005, reaching all-time highs. West Texas Intermediate ("WTI") averaged US$55.45 per bbl for the nine months ended September 30, 2005, an increase of 42% compared to US$39.13 per bbl in the comparable period in 2004. In the third quarter of 2005, WTI averaged US$63.17 per bbl, up 44% from US$43.85 per bbl in the comparable period in 2004, and up 19% from US$53.13 per bbl in the second quarter of 2005. Increased WTI pricing was attributable to a number of factors, including continued tightness in world oil supplies caused by demand growth, particularly in the United States, China and India, the impact of weather-related supply issues in the Gulf of Mexico caused by hurricanes Katrina and Rita, refinery bottlenecks, and continued political instability in various parts of the world. Subsequent to September 30, 2005, crude oil prices continued to remain volatile, but have declined due to concerns over reduced demand and strong storage levels.

Higher WTI pricing is not fully reflected in the Company's crude oil price realizations. 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 74% to US$19.74 per bbl for the nine months ended September 30, 2005 from US$11.37 per bbl in the comparable period in 2004. For the three months ended September 30, 2005, heavy crude oil differentials increased 49% compared to the third quarter of 2004 to average US$18.73 per bbl, primarily due to higher WTI pricing, but narrowed 12% from the second quarter of 2005 despite higher WTI pricing due to increased demand for heavy blends relative to light blends. This reflects normal seasonal narrowing related to the summer asphalt season.

Year to date average heavy crude oil differentials in 2005 continued to be higher than the long-term average primarily due to first and second quarter physical limitations for demand at refineries and due to plant turnarounds and maintenance in the first half of the year, which exacerbated the impact of normal seasonality. Additional problems at refineries and upgraders, the higher prices of diluents required to reduce the viscosity of heavy crude oil production to meet requirements for transmission in sales pipelines, and the stronger Canadian dollar, also contributed to lower heavy crude oil price realizations. A strengthening in the Canadian dollar reduces the Canadian dollar sales price the Company receives for its crude oil production as crude oil prices are based on US dollar denominated benchmarks.

North America natural gas prices also remained strong due to concerns around supply, including hurricane-related losses in the Gulf of Mexico and the impact of higher crude oil prices. NYMEX natural gas prices increased 22% to average US$7.12 per mmbtu for the nine months ended September 30, 2005, up from US$5.84 per mmbtu in the comparable period in 2004. In the third quarter of 2005, NYMEX natural gas prices increased 41% to average US$8.23 per mmbtu, up from US$5.85 per mmbtu in the comparable period in 2004, and increased 21% from US$6.80 per mmbtu in the prior quarter. AECO natural gas pricing moved directionally with NYMEX, increasing 11% to average $7.03 per GJ for the nine months ended September 30, 2005, up from $6.34 per GJ in the comparable period in 2004. AECO natural gas prices increased 22% to average $7.73 per GJ in the third quarter of 2005, up from $6.32 per GJ in the comparable period in 2004, and increased 10% from $7.00 per GJ in the prior quarter.

The Company believes that natural gas prices will continue to remain high throughout the winter heating season due to continued tight supply.

PRODUCT PRICES [1]

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs ($/bbl)					
North America	**$ 51.77**	$ 35.24	$ 38.31	**$ 40.20**	$ 33.93
North Sea	**$ 74.46**	$ 64.81	$ 57.39	**$ 66.49**	$ 50.85
Offshore West Africa	**$ 59.09**	$ 58.24	$ 53.86	**$ 59.51**	$ 48.33
Company average	**$ 57.35**	$ 42.51	$ 43.50	**$ 47.04**	$ 38.37
Natural gas ($/mcf)					
North America	**$ 8.69**	$ 7.38	$ 6.36	**$ 7.60**	$ 6.51
North Sea	**$ 2.64**	$ 3.07	$ 3.17	**$ 3.11**	$ 3.84
Offshore West Africa	**$ 5.52**	$ 6.88	$ 6.31	**$ 6.39**	$ 5.36
Company average	**$ 8.61**	$ 7.33	$ 6.24	**$ 7.53**	$ 6.40
Company average ($/boe)	**$ 54.87**	**$** 43.05	$ 40.92	**$ 46.17**	**$** 38.44
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**60%**	54%	60%	**57%**	55%
Natural gas	**40%**	46%	40%	**43%**	45%

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

Company realized crude oil prices increased 23% to average $47.04 per bbl for the nine months ended September 30, 2005, up from $38.37 per bbl in the comparable period in 2004. For the third quarter 2005, realized crude prices increased 32% to average $57.35 per bbl, up from $43.50 per bbl in the comparable period in 2004 and up 35% from the second quarter of 2005. The increase in realized crude oil prices was primarily due to higher benchmark world crude oil prices, as well as a change in production mix to a higher proportion of North Sea and Offshore West Africa production, offset by higher heavy crude oil differentials and a stronger Canadian dollar, which increased 9% in relation to the US dollar.

The Company's realized natural gas price increased 18% to average $7.53 per mcf for the nine months ended September 30, 2005, up from $6.40 per mcf in the comparable period in 2004, primarily due to a continued strengthening in benchmark natural gas pricing in the third quarter. In the third quarter of 2005, the realized natural gas price averaged $8.61 per mcf, up 38% from $6.24 per mcf in the comparable period in 2004 and up 17% from $7.33 per mcf in the prior quarter.

North America

North America realized crude oil prices increased 18% to average $40.20 per bbl for the nine months ended September 30, 2005, up from $33.93 per bbl in the comparable period in 2004. Realized crude oil prices in the third quarter of 2005 averaged $51.77 per bbl, up from $38.31 per bbl in the comparable period in 2004 and $35.24 per bbl in the prior quarter. The increase in the realized crude oil price year over year was mainly due to higher benchmark crude oil prices, partially offset by wider heavy crude oil differentials and the strengthening Canadian dollar. The increase compared to the second quarter was primarily due to higher benchmark crude oil prices and a narrowing heavy crude oil differential, offset by a stronger Canadian dollar.

North America continues to focus on its crude oil marketing strategy, including the development of a blending strategy, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with 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 third 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 crude 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 Nederland Texas, near the Gulf Coast.

North America realized natural gas prices increased 17% to average $7.60 per mcf for the nine months ended September 30, 2005, up from $6.51 per mcf in the comparable period in 2004. In the third quarter of 2005, the realized natural gas price averaged $8.69 per mcf, up 37% from $6.36 per mcf in the comparable period in 2004 and up 18% from $7.38 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 by product type is as follows:

	Q3 2005	Q2 2005	Q3 2004
Wellhead Price [(1)]			
Light crude oil and NGLs (C$/bbl)	**$ 66.62**	$ 55.66	$ 48.77
Pelican Lake crude oil (C$/bbl)	**$ 50.30**	$ 34.24	$ 36.39
Primary heavy crude oil (C$/bbl)	**$ 48.86**	$ 28.42	$ 35.40
Thermal heavy crude oil (C$/bbl)	**$ 44.84**	$ 26.71	$ 35.19
Natural gas (C$/mcf)	**$ 8.69**	$ 7.38	$ 6.36

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

(2)

North Sea

North Sea realized crude oil prices increased 31% to average $66.49 per bbl for the nine months ended September 30, 2005, up from $50.85 per bbl in the comparable period in 2004, and increased 30% to average $74.46 per bbl in the third quarter of 2005, up from $57.39 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 a narrowing of the average Brent differential, offset by the strengthening Canadian dollar. Realized prices increased 15% in the third quarter of 2005 compared to the second quarter due to higher benchmark world oil prices, offset by a 4% strengthening in the Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 23% to average $59.51 per bbl for the nine months ended September 30, 2005, up from $48.33 per bbl in the comparable period in 2004, and averaged $59.09 per bbl in the third quarter of 2005, up 10% from $53.86 per bbl in the comparable period in 2004 and marginally from the prior quarter. The increase in realized crude oil prices from the comparable periods was due to higher world benchmark crude oil prices, offset by the strengthening Canadian dollar.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs (bbl/d)					
North America	**231,260**	215,693	214,336	**218,774**	203,449
North Sea	**73,543**	62,884	71,517	**69,198**	62,938
Offshore West Africa	**29,921**	10,487	11,409	**16,064**	11,665
	334,724	289,064	297,262	**304,036**	278,052
Natural gas (mmcf/d)					
North America	**1,400**	1,434	1,336	**1,421**	1,319
North Sea	**18**	17	53	**19**	54
Offshore West Africa	**5**	3	7	**4**	8
	1,423	1,454	1,396	**1,444**	1,381
Total barrel of oil equivalent (boe/d)	**571,911**	531,380	529,946	**544,688**	508,157
Product mix					
Light crude oil and NGLs	**27%**	24%	24%	**25%**	24%
Pelican Lake crude oil	**4%**	4%	4%	**4%**	4%
Primary heavy crude oil	**16%**	17%	18%	**17%**	19%
Thermal heavy crude oil	**11%**	9%	10%	**10%**	8%
Natural gas	**42%**	46%	44%	**44%**	45%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs (bbl/d)					
North America	**200,055**	189,137	187,098	**189,630**	177,625
North Sea	**73,424**	62,779	71,396	**69,101**	62,831
Offshore West Africa	**29,162**	10,160	11,108	**15,624**	11,326
	302,641	262,076	269,602	**274,355**	251,782
Natural gas (mmcf/d)					
North America	**1,085**	1,143	1,031	**1,231**	1,033
North Sea	**18**	17	53	**19**	54
Offshore West Africa	**5**	3	7	**4**	8
	1,108	1,163	1,091	**1,254**	1,095
Total barrel of oil equivalent (boe/d)	**487,292**	455,866	451,462	**483,379**	434,239

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.

Record total crude oil and natural gas production averaged 544,688 boe/d for the nine months ended September 30, 2005, an increase of 7% or 36,531 boe/d from the comparable period in 2004. Third quarter total production in 2005 also reached record levels of 571,911 boe/d, an increase of 8% or 41,965 boe/d compared to the third quarter of 2004. The increase in production year over year was due to the Company's extensive North America capital expenditure program and the commencement of production from the Baobab Field offshore Côte d'Ivoire in the third quarter as well as accretive acquisitions completed in 2004.

Total crude oil and NGLs production for the nine months ended September 30, 2005 increased 9% to 304,036 bbl/d from 278,052 bbl/d for the comparable period in 2004. In the third quarter of 2005, production was 334,724 bbl/d, an increase of 13% from 297,262 bbl/d in the third quarter of 2004. Crude oil and NGLs production in the third quarter of 2005 was in line with the Company's previously issued guidance of 322,000 to 344,000 bbl/d.

Natural gas production continues to represent the Company's largest product offering. Natural gas production for the nine months ended September 30, 2005 increased 5% or 63 mmcf/d to average 1,444 mmcf/d compared to 1,381 mmcf/d for the comparable period in 2004. Natural gas production of 1,423 mmcf/d in the third quarter continued to be affected by wet weather in the Company's core regions in North America. In addition, due to the overall increase in industry activity, the market for the necessary oilfield services and material has become very competitive, resulting in drilling, completion, tie-in and maintenance delays. As a result, the Company's third quarter natural gas production was at the low end of the Company's previously issued guidance of 1,423 to 1,468 mmcf/d.

The Company expects annual production levels in 2005 to average 1,436 to 1,448 mmcf/d of natural gas and 308 to 316 mbbl/d of crude oil and NGLs. Fourth quarter 2005 production guidance is 1,411 to 1,460 mmcf/d of natural gas and 323 to 352 mbbl/d of crude oil and NGLs.

North America

North America crude oil and NGLs production for the nine months ended September 30, 2005 increased 8% or 15,325 bbl/d to average 218,774 bbl/d, up from 203,449 bbl/d in the comparable period in 2004. Production in the third quarter of 2005 increased 8% or 16,924 bbl/d to average 231,260 bbl/d, up from 214,336 bbl/d in the comparable period in 2004 and 7% higher than the second quarter 2005 production of 215,693 bbl/d. The increase in crude oil and NGLs production was mainly due to the timing of Primrose production cycles and the positive results of the Pelican Lake waterflood project.

North America natural gas production for the nine months ended September 30, 2005 increased 8% or 102 mmcf/d to average 1,421 mmcf/d, up from 1,319 mmcf/d in the comparable period in 2004. Natural gas production increased as a result of organic growth and accretive property acquisitions in 2004, but was negatively impacted by the early arrival of spring breakup and weather related delays due to unusually wet conditions. In the third quarter of 2005, production increased 5% or 64 mmcf/d to average 1,400 mmcf/d, up from 1,336 mmcf/d in the comparable period in 2004, but continued to be impacted by wet weather conditions and the increased demand for oilfield services and materials, which caused delays in the timing of production.

North Sea

North Sea crude oil production for the nine months ended September 30, 2005 was 69,198 bbl/d, an increase of 10% from 62,938 bbl/d in the comparable period in 2004. Crude oil production in the third quarter of 2005 reached record levels and increased to 73,543 bbl/d, 3% higher than production of 71,517 bbl/d in the comparable period in 2004, and 17% higher than second quarter 2005 production of 62,884 bbl/d, following the completion of scheduled maintenance. Production remained below expectations in the third quarter and continues to be negatively impacted by a production curtailment in the Murchison Field resulting from the shut in of third party natural gas export facilities and as a result of the loss of productivity from some wells in the Columba Terraces.

Natural gas production in the North Sea for the nine months ended September 30, 2005 decreased 65% to average 19 mmcf/d, down from 54 mmcf/d in the comparable period in 2004. Natural gas production in the third quarter of 2005 of 18 mmcf/d decreased 66% from third quarter 2004, but was consistent with second quarter of 2005. The decrease year over year 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.

Offshore West Africa

Offshore West Africa crude oil production for the nine months ended September 30, 2005 increased 38% to 16,064 bbl/d from 11,665 bbl/d in the comparable period in 2004. The production increase was primarily due to commencement of production from the 57.61% owned and operated Baobab Field in August 2005, as well as production from the second of four new (2.3 net) infill wells drilled in East Espoir. Third quarter 2005 production of 29,921 bbl/d increased 162% compared to production of 11,409 bbl/d in the third quarter of 2004, and increased by 185% from second quarter 2005 production of 10,487 bbl/d as a result of production commencing from the Baobab Field.

ROYALTIES

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs ($/bbl)					
North America	**$ 6.99**	$ 4.34	$ 4.87	**$ 5.36**	$ 4.31
North Sea	**$ 0.12**	$ 0.11	$ 0.09	**$ 0.10**	$ 0.09
Offshore West Africa	**$ 1.54**	$ 1.81	$ 1.42	**$ 1.69**	$ 1.40
Company average	**$ 5.11**	$ 3.33	$ 3.59	**$ 4.00**	$ 3.23
Natural gas ($/mcf)					
North America	**$ 1.96**	$ 1.50	$ 1.45	**$ 1.59**	$ 1.41
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.13**	$ 0.21	$ 0.17	**$ 0.18**	$ 0.16
Company average	**$ 1.93**	$ 1.48	$ 1.39	**$ 1.57**	$ 1.35
Company average ($/boe)	**$ 7.84**	$ 5.85	$ 5.68	**$ 6.40**	$ 5.43
Percentage of revenue (1)					
Crude oil and NGLs	**9%**	9%	8%	**9%**	8%
Natural gas	**22%**	20%	22%	**21%**	21%
Boe	**14%**	14%	14%	**14%**	14%

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

North America

North America crude oil and NGLs royalties per bbl for the nine and three months ended September 30, 2005 increased from the comparable periods in 2004 primarily due to higher benchmark crude oil prices. Third quarter 2005 crude oil and NGLs royalties per bbl increased from the second quarter due to higher benchmark crude oil prices, offset by 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 increased from the comparable periods in 2004 and the prior quarter due to higher benchmark 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			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Crude oil and NGLs ($/bbl)					
North America	**$ 10.77**	$ 10.14	$ 9.10	**$ 10.34**	$ 8.89
North Sea	**$ 15.15**	$ 17.41	$ 13.88	**$ 15.75**	$ 13.68
Offshore West Africa	**$ 5.81**	$ 8.47	$ 8.05	**$ 7.72**	$ 7.52
Company average	**$ 11.48**	$ 11.66	$ 10.21	**$ 11.48**	$ 9.92
Natural gas ($/mcf)					
North America	**$ 0.74**	$ 0.68	$ 0.63	**$ 0.70**	$ 0.61
North Sea	**$ 2.30**	$ 2.92	$ 2.48	**$ 2.57**	$ 2.01
Offshore West Africa	**$ 1.09**	$ 1.37	$ 1.39	**$ 1.21**	$ 1.33
Company average	**$ 0.76**	$ 0.71	$ 0.71	**$ 0.72**	$ 0.67
Company average ($/boe)	**$ 8.56**	$ 8.29	$ 7.59	**$ 8.31**	$ 7.26

North America

North America crude oil and NGLs production expense per bbl for the nine and three months ended September 30, 2005 increased from the comparable periods in 2004 and the prior quarter. The increase was primarily due to higher industry wide service costs, higher fuel related expenses, and as a larger portion of the Company's crude oil production was comprised of higher cost thermal crude oil. These factors were offset by the positive impact of higher production.

North America natural gas production expense per mcf for the nine and three months ended September 30, 2005 increased from the comparable period in 2004 and the prior quarter. The increase was due to the service and commodity cost pressures noted above, offset by the positive impact of higher production. It is expected fourth quarter 2005 North America natural gas production expense per mcf will decrease over the third quarter 2005.

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. Production expenses in the first nine months of 2005 compared to 2004 were primarily impacted by the curtailment of production at East Espoir to facilitate the infill drilling program and the modifications to the FPSO to accommodate West Espoir production. Production costs decreased in the third quarter of 2005 compared to the second quarter as a result of the commencement of production from the Baobab Field.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Revenue	**$ 18**	$ 17	$ 17	**$ 56**	$ 50
Production expense	**5**	5	6	**16**	15
Midstream cash flow	**13**	12	11	**40**	35
Depreciation	**2**	2	2	**6**	5
Segment earnings before taxes	**$ 11**	$ 10	$ 9	**$ 34**	$ 30

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 is 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 manage the full range of costs associated with the development and marketing of its heavy crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION (1)

	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Expense ($ millions)	**$ 503**	$ 482	$ 451	**$ 1,457**	$ 1,263
$/boe	**$ 9.75**	$ 9.98	$ 9.27	**$ 9.87**	$ 9.07

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

Depletion, Depreciation and Amortization ("DD&A") for the nine and three months ended September 30, 2005 increased in total and on a boe basis from the comparable periods in 2004. The increase in DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with recent acquisitions, future abandonment costs associated with the acquisition of additional properties in the North Sea, and higher estimated future costs to develop the Company's proved undeveloped reserves. The increase in DD&A in total in the third quarter of 2005 compared to the second quarter was primarily due to higher production levels.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Expense ($ millions)	**$ 18**	$ 17	$ 14	**$ 53**	$ 35
$/boe	**$ 0.34**	$ 0.36	$ 0.29	**$ 0.36**	$ 0.25

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			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004(1)	**Sep 30 2005**	Sep 30 2004(1)
Net expense ($ millions)	**$ 38**	$ 42	$ 32	**$ 115**	$ 89
$/boe	**$ 0.75**	$ 0.85	$ 0.65	**$ 0.78**	$ 0.64

(1) Restated to conform to current year presentation.

Administration expense for the nine months ended September 30, 2005 increased in total and on a boe basis from the comparable period in 2004 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 decrease from the second quarter of 2005 was due to lower compensation expense associated with the Share Bonus Plan and higher overhead recoveries associated with the Company's capital program.

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 nine months ended September 30, 2005, the Company recognized $14 million of compensation expense under the Share Bonus Plan (September 30, 2004 - $8 million).

STOCK-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2005**	Jun 30 2005	Sep 30 2004(1)	**Sep 30 2005**	Sep 30 2004(1)
Stock option plan	**$ 199**	$ 215	$ 119	**$ 598**	$ 225

(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 design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of 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 $598 million ($406 million after tax) stock-based compensation expense for the nine months ended September 30, 2005 in connection with the 105% appreciation in the Company's share price, and a $199 million ($135 million after tax) stock-based compensation expense as a result of the 18% appreciation in the Company's share price in the third quarter of 2005 (September 30, 2005 - C$52.50; June 30, 2005 - C$44.40; 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 September 30, 2005. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the nine months ended September 30, 2005, the Company paid $175 million for stock options surrendered for cash settlement (September 30, 2004 - $66 million).

INTEREST EXPENSE

	Three Months Ended			Nine Months Ended	
	Sep 30 2005	Jun 30 2005	Sep 30 2004(1)	**Sep 30 2005**	Sep 30 2004(1)
Interest expense, net ($ millions)	**$ 38**	$ 40	$ 47	**$ 121**	$ 141
$/boe	**$ 0.73**	$ 0.82	$ 0.99	**$ 0.82**	$ 1.01
Average effective interest rate	**6.0%**	5.2%	5.2%	**5.5%**	5.3%

(1) Restated to conform to current year presentation.

Net interest expense decreased on a total and boe basis for the nine and three months ended September 30, 2005 from the comparable periods in 2004 primarily due to the capitalization of construction period interest related to the Horizon Project in 2005 (nine months ended September 30, 2005 – $45 million; three months ended September 30, 2005 - $20 million). Pre-capitalization interest increased over comparable periods in 2004 mainly due to higher overall fixed rate debt levels.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various financial instruments to manage its commodity price, foreign currency and interest rate exposures on US dollar denominated debt. These financial instruments are not used for trading or speculative purposes.

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". On adoption, only those 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 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 US dollar denominated 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. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized immediately in net earnings. Gains or losses on the termination of financial instruments that have not been accounted for as hedges are recognized in net earnings immediately.

RISK MANAGEMENT

($ millions)	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 319**	$ 94	$ 176	**$ 518**	$ 321
Natural gas financial instruments	**49**	2	1	**41**	3
Interest rate swaps	**-**	-	(6)	**(8)**	(25)
	$ 368	$ 96	$ 171	**$ 551**	$ 299
Unrealized loss (gain)					
Crude oil and NGLs financial instruments	**$ 286**	$ 168	$ 107	**$ 1,361**	$ 274
Natural gas financial instruments	**348**	(50)	-	**384**	-
Interest rate swaps	**(1)**	1	(2)	**5**	3
	$ 633	$ 119	$ 105	**$ 1,750**	$ 277
Total	**$ 1,001**	$ 215	$ 276	**$ 2,301**	$ 576

The realized loss from crude oil and NGLs and natural gas financial instruments decreased the Company's average realized prices as follows:

	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Crude oil and NGLs ($/bbl)	**$ 10.69**	$ 3.58	$ 6.45	**$ 6.31**	$ 4.22
Natural gas ($/mcf)	**$ 0.38**	$ 0.02	$ 0.01	**$ 0.10**	$ 0.01

The realized gain on non-designated interest rate swaps decreased the Company's interest expense as follows:

($ millions)	Three Months Ended Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Interest expense as reported	**$ 38**	$ 40	$ 47	**$ 121**	$ 141
Realized risk management gain	**-**	-	(6)	**(8)**	(25)
	$ 38	$ 40	$ 41	**$ 113**	$ 116
Average effective interest rate	**6.0%**	5.2%	4.5%	**5.1%**	4.4%

As effective as economic hedges are against reference commodity prices, a substantial portion of the crude oil and natural gas 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 September 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 and natural gas forward pricing in 2005, the Company recorded a $1,750 million ($1,190 million after tax) unrealized loss on its risk management activities for the nine months ended September 30, 2005, including a $633 million ($430 million after tax) unrealized loss for the three months ended September 30, 2005.

In addition to the risk management liability recognized on the balance sheet at September 30, 2005, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $1,638 million (December 31, 2004 – net unrecognized asset of $33 million).

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2005**	Jun 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Realized foreign exchange loss (gain)	**$ 5**	$ (6)	$ 1	**$ (13)**	$ (13)
Unrealized foreign exchange (gain) loss	**(124)**	16	(100)	**(108)**	(17)
	$ (119)	$ 10	$ (99)	**$ (121)**	$ (30)

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. 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 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.

In 2005, the majority of the realized foreign exchange gain or loss is a result of the effects of foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. In addition, a foreign exchange gain was realized on the repayment of the Company’s preferred securities. The majority of the unrealized foreign exchange (gain) loss is 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 third quarter of 2005 at US$0.8613 compared to US$0.8308 at December 31, 2004 (June 30, 2005 - US$0.8159; September 30, 2004 - US$0.7912).

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 Sep 30 2005	Three Months Ended Jun 30 2005	Three Months Ended Sep 30 2004	Nine Months Ended Sep 30 2005	Nine Months Ended Sep 30 2004
Taxes other than income tax					
Current	**$ 75**	$ 36	$ 76	**$ 153**	$ 163
Deferred	**(14)**	4	(14)	**(10)**	(13)
	$ 61	$ 40	$ 62	**$ 143**	$ 150
Current income tax					
North America – Current income tax	**$ 20**	$ 30	$ 6	**$ 80**	$ 88
North America – Large corporations tax	**5**	4	2	**11**	6
North Sea	**57**	28	(19)	**124**	18
Offshore West Africa	**6**	4	3	**13**	10
	$ 88	$ 66	$ (8)	**$ 228**	$ 122
Future income tax expense (recovery) (1)	**$ 18**	$ 62	$ 153	**$ (161)**	$ 216
Effective income tax rate(2)	**41.3%**	37.0%	31.8%	**> 100%**	29.1%

(1) Restated to conform to current year presentation.

(2) For the nine months ended September 30, 2005, the Company's effective tax rate was greater than 100% due to the combined effects of jurisdictional tax rate differences between the various business segments, together with a nominal consolidated net earnings before taxes. The company anticipates that its 2005 consolidated effective tax rate will be in the range of 35% to 40%.

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 allowing for certain deductions including abandonment expenditures. Taxes other than income taxes in the third quarter of 2005 increased from the prior quarter as a result of higher benchmark crude oil prices.

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 they are deployed.

The North Sea current income tax expense for the nine and three months ended September 30, 2005 increased from the comparable period in 2004 due mainly to higher realized product prices, increased production volumes and the deductibility of acquired tax pools in the UK in 2004.

During the third quarter of 2005, the province of British Columbia introduced legislation to reduce its corporate income tax rate by 1.5% effective July 1, 2005. As a result, the North America future income tax liability was reduced by $19 million. 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 Sep 30 2005	Jun 30 2005	Sep 30 2004	Nine Months Ended Sep 30 2005	Sep 30 2004
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions (1)	**$ -**	$ (341)	$ 290	**$ (339)**	$ 1,074
Land acquisition and retention	**69**	52	37	**157**	107
Seismic evaluations	**31**	20	25	**92**	68
Well drilling, completion and equipping	**431**	306	221	**1,371**	1,035
Pipeline and production facilities	**266**	283	190	**981**	636
Total net reserve replacement expenditures	**797**	320	763	**2,262**	2,920
Horizon Oil Sands Project	**452**	275	84	**942**	233
Midstream	**(1)**	-	2	**3**	5
Abandonments	**19**	7	14	**30**	27
Head office	**5**	7	12	**16**	27
Total net capital expenditures (2)	**$ 1,272**	$ 609	$ 875	**$ 3,253**	$ 3,212
By segment					
North America	**$ 618**	$ 110	$ 339	**$ 1,668**	$ 2,214
North Sea	**100**	112	370	**269**	521
Offshore West Africa	**79**	97	54	**320**	185
Other	**-**	1	-	**5**	-
Horizon Oil Sands Project	**452**	275	84	**942**	233
Midstream	**(1)**	-	2	**3**	5
Abandonments	**19**	7	14	**30**	27
Head office	**5**	7	12	**16**	27
Total	**$ 1,272**	$ 609	$ 875	**$ 3,253**	$ 3,212

(1) Includes Business Combinations.

(2) The net capital expenditures do not include non-cash property, plant and equipment additions or disposals.

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 for the nine months ended September 30, 2005 were $3,253 million compared to $3,212 million in the comparable period in 2004. 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 1,357 net wells consisting of 611 natural gas wells, 437 crude oil wells, 215 stratigraphic test and service wells, and 94 wells that were dry compared to 1,116 net wells in the first nine months of 2004. The Company achieved an overall success rate of 92%, excluding stratigraphic test and service wells. These 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 third quarter of 2005 were $1,272 million compared to $875 million in the comparable period in 2004 and $609 million in the prior quarter. The increase was primarily related to increased capital expenditures on the Horizon Oil Sands Project and increased activity on the North America conventional drilling program. In the third quarter the Company drilled a total of 430 net wells consisting of 213 natural gas wells, 179 crude oil wells, 16 stratigraphic test and service wells, and 22 wells that were dry compared to 145 net wells in the third quarter of 2004. The Company achieved an overall success rate of 95%, excluding stratigraphic test and service wells.

North America

North America accounted for approximately 82% of the total capital expenditures for the first nine months of 2005 compared to approximately 74% in the comparable period in 2004.

During the first nine months of 2005, the Company drilled 611 net natural gas wells, including 173 wells in Northeast British Columbia, 120 wells in the Northern Plains region, 105 wells in Northwest Alberta, and 213 wells in the Southern Plains region. The Company also drilled 427 net crude oil wells during the first nine months of 2005. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 219 heavy crude oil wells, 57 Pelican Lake crude oil wells, 88 thermal crude oil wells, and 6 light crude oil wells were drilled. In the third quarter the Company drilled 213 net natural gas wells and 175 net crude oil wells, consisting of 106 heavy crude oil wells, 21 Pelican Lake crude oil wells, 19 thermal crude oil wells and 29 light crude oil wells.

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 kilometers from its existing Primrose South steam plant and 25 kilometers 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 Company plans to enhance the waterflood process by the use of a polymer flood. Facilities for the Pelican Lake polymer flood were installed in the second quarter of 2005 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 fourth quarter, the Company's drilling activity is expected to be comprised of 346 natural gas wells, and 159 crude oil wells excluding stratigraphic test 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 third quarter, the Horizon Project continued with detailed engineering and infrastructure development activity. Due to wet weather, site preparation work has fallen behind schedule, but all major milestones required before winter have been completed. In the third quarter, the first of three camps was opened, the Aerodrome commenced operations, the reactors were shipped from India and Japan, the Hydrotreating and Extraction areas were turned over for construction and the first pipe rack module was delivered to the site.

In addition to direct construction costs, the Company capitalized $45 million of construction period interest and $64 million of stock-based compensation costs during the nine months ended September 30, 2005.

In the fourth quarter of 2005, the shop maintenance building will be ready for occupancy, the assembly of the reactor will commence, the second of three on-site camps will be substantially completed, the earth work for the raw water and recycle water pond systems will commence and the detailed engineering plan is expected to be over 55% complete.

North Sea

In the third quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the third quarter 2.5 net wells were drilled, with an additional 3.6 net wells drilling at quarter-end.

In the third quarter of 2005, production from the Kyle Field was diverted to the Banff FPSO. Under the terms of an early termination agreement, the existing Kyle FPSO was 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 fourth quarter, drilling of a two well program in the Thelma Field will commence targeting unswept areas of the field.

Offshore West Africa

Offshore West Africa capital expenditures include the development of the 57.61% owned and operated Baobab Field, which commenced production on August 18, 2005 at approximately 30 mbbl/d net to the Company.

At East Espoir, the second of four (2.3 net) infill wells scheduled for drilling was completed. 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 on site and is expected to be installed in late 2005. 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)	**Sep 30 2005**	Jun 30 2005	Dec 31 2004	Sep 30 2004[3]
Working capital deficit [1]	**$ 2,106**	$ 1,340	$ 652	$ 633
Long-term debt	**$ 3,235**	$ 3,649	$ 3,538	$ 3,415
Shareholders' equity				
Share capital	**$ 2,433**	$ 2,428	$ 2,408	$ 2,400
Retained earnings	**4,759**	4,655	4,922	4,372
Foreign currency translation adjustment	**(11)**	(4)	(6)	1
Total	**$ 7,181**	$ 7,079	$ 7,324	$ 6,773
Debt to cash flow [1] [2]	**0.8x**	0.9x	1.0x	0.9x
Debt to EBITDA [1] [2]	**0.7x**	0.8x	0.9x	0.8x
Debt to book capitalization [1]	**32.3%**	35.2%	33.8%	32.9%
Debt to market capitalization [1]	**10.8%**	13.9%	21.4%	19.7%
After tax return on average common shareholders' equity [2]	**7.4%**	9.9%	21.4%	17.2%
After tax return on average capital employed [1] [2]	**5.8%**	7.5%	15.3%	12.5%

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

(2) Based on trailing 12-month activity.

(3) Restated to conform to current year presentation.

At September 30, 2005, the working capital deficit was $2,106 million and included the current portion of other long-term liabilities of $1,877 million, comprised of stock-based compensation of $531 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $1,346 million. The repayment of the stock-based compensation liability is dependant upon both 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 cash settlement amount of the risk management financial derivative instruments will vary depending upon the underlying crude oil and natural gas prices at the time of final settlement of the financial derivative instruments, as compared to their value at September 30, 2005.

The Company is committed to maintaining a strong financial position throughout construction of the Horizon Project. In the third quarter of 2005, strong operational results and high commodity prices resulted in debt to book capitalization levels of approximately 32%. The Company believes it has the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of exceptionally low-risk conventional crude oil and natural gas growth opportunities. The financing of the first phase of the Horizon Project development is 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 September 30, 2005, such as Baobab, Primrose and West Espoir have provided identified growth in production volumes in 2005 and 2006, and will generate incremental free cash flows during the period 2006 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 75% of the fourth quarter 2005 expected crude oil volumes and approximately 55% of expected 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 70% of the fourth quarter 2005 expected natural gas volumes and approximately 55% 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 September 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 September 30, 2005, the Company had undrawn bank lines of credit of $3,360 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.

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.

In August 2005, the Company filed a short form prospectus that allows for the issue of up to $2 billion of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early prepayment premium of US$11 million as required under the Note Purchase Agreement.

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 September 30, 2005, there were 536,717,000 common shares outstanding. As at October 28, 2005, the Company had 536,583,000 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 at September 30, 2005, the Company had purchased 300,000 common shares at an average price of $53.27 per common share for a total cost of $16 million. Subsequent to September 30, 2005, the Company repurchased an additional 150,000 common shares for a total cost of $7 million.

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, 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 primarily relate to debt repayments, operating leases relating to office space and offshore production and storage vessels, and firm commitments for gathering, processing and transmission services. The following table summarizes the Company's commitments as at September 30, 2005:

($ millions)		2005		2006		2007		2008		2009		Thereafter
Natural gas transportation	$	49	$	162	$	103	$	79	$	39	$	165
Oil transportation and pipeline	$	3	$	30	$	31	$	70	$	56	$	1,033
FPSO operating leases	$	36	$	54	$	51	$	51	$	51	$	222
Baobab Project	$	5	$	-	$	-	$	-	$	-	$	-
Offshore drilling and other	$	78	$	-	$	-	$	-	$	-	$	-
Electricity	$	7	$	39	$	41	$	-	$	-	$	-
Office leases	$	5	$	20	$	20	$	19	$	20	$	29
Processing	$	1	$	2	$	-	$	-	$	-	$	-
Long-term debt (1)	$	194	$	-	$	161	$	36	$	36	$	2,954

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

During the third quarter of 2005, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future Horizon crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. Annual toll payments before operating costs will be approximately $35 million.

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 is expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion to be incurred in 2005, $2.6 billion to be incurred in 2006 and $2.8 billion to be incurred in 2007 and 2008.

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, following 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 nine months ended September 30, 2005, pre-tax interest of $45 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 third 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	$ 106	$ 0.20	$ 75	$ 0.14
Including financial derivatives	$ 26	$ 0.05	$ 17	$ 0.03
Natural gas – AECO C$0.10/mcf [2]				
Excluding financial derivatives	$ 35	$ 0.07	$ 22	$ 0.04
Including financial derivatives	$ 23	$ 0.04	$ 14	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 127	$ 0.24	$ 72	$ 0.13
Natural gas – 10 mmcf/d	$ 22	$ 0.04	$ 10	$ 0.02
Foreign currency rate change				
$0.01 change in C$ in relation to US$[2]				
Excluding financial derivatives	$ 79-81	$ 0.15	$ 31-32	$ 0.06
Including financial derivatives	$ 79-81	$ 0.15	$ 31-32	$ 0.06
Interest rate change - 1%	$ 7	$ 0.01	$ 7	$ 0.01

(1) The sensitivities are calculated based on 2005 third 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

($/boe, except daily production) [4]	Three Months Ended **Sep 30 2005**	 Jun 30 2005	 Sep 30 2004	Nine Months Ended **Sep 30 2005**	 Sep 30 2004
Daily production, before royalties (boe/d)	**571,911**	531,380	529,946	**544,688**	508,157
Sales price [1]	**$ 54.87**	$ 43.05	$ 40.92	**$ 46.17**	$ 38.44
Royalties	**7.84**	5.85	5.68	**6.40**	5.43
Production expense [2]	**8.56**	8.29	7.59	**8.31**	7.26
Netback	**38.47**	28.91	27.65	**31.46**	25.75
Midstream contribution [2]	**(0.26)**	(0.25)	(0.25)	**(0.27)**	(0.25)
Administration [3]	**0.75**	0.85	0.65	**0.78**	0.64
Interest, net	**0.73**	0.82	0.99	**0.82**	1.01
Realized risk management loss	**7.12**	1.98	3.51	**3.73**	2.15
Realized foreign exchange gain	**0.10**	(0.14)	0.01	**(0.09)**	(0.09)
Taxes other than income tax - current	**1.46**	0.76	1.55	**1.04**	1.17
Current income tax - North America	**0.39**	0.62	0.12	**0.54**	0.63
Current income tax - Large Corporations Tax	**0.07**	0.09	0.06	**0.07**	0.04
Current income tax - North Sea	**1.11**	0.59	(0.42)	**0.84**	0.12
Current income tax - Offshore West Africa	**0.12**	0.08	0.07	**0.09**	0.07
Cash flow	**$ 26.88**	$ 23.51	$ 21.36	**$ 23.91**	$ 20.26

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

(2) Excluding intersegment elimination.

(3) Restated to conform to current year presentation.

(4) All tabular amounts except for daily production figures are based on daily sales volumes.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		**Sep 30 2005**		Dec 31 2004
ASSETS				
Current assets				
Cash	**$**	**12**	$	28
Accounts receivable and other		**2,163**		1,138
Current portion of other long-term assets (note 2)		**-**		72
		2,175		1,238
Property, plant and equipment (net)		**18,660**		17,064
Other long-term assets (note 2)		**109**		108
	$	**20,944**	$	18,410
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**479**	$	379
Accrued liabilities		**1,731**		1,057
Current portion of long-term debt (note 3)		**194**		194
Current portion of other long-term liabilities (note 4)		**1,877**		260
		4,281		1,890
Long-term debt (note 3)		**3,235**		3,538
Other long-term liabilities (note 4)		**1,570**		1,208
Future income tax (note 5)		**4,677**		4,450
		13,763		11,086
SHAREHOLDERS' EQUITY				
Share capital (note 6)		**2,433**		2,408
Retained earnings		**4,759**		4,922
Foreign currency translation adjustment (note 7)		**(11)**		(6)
		7,181		7,324
	$	**20,944**	$	18,410

Commitments (note 10)

Consolidated statements of earnings (loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Sep 30 2005	Three Months Ended Sep 30 2004	Nine Months Ended Sep 30 2005	Nine Months Ended Sep 30 2004
Revenue	**$ 2,918**	$ 2,075	**$ 7,075**	$ 5,578
Less: royalties	**(403)**	(276)	**(945)**	(756)
Revenue, net of royalties	**2,515**	1,799	**6,130**	4,822
Expenses				
Production	**446**	376	**1,240**	1,023
Transportation	**71**	63	**204**	179
Depletion, depreciation and amortization	**505**	453	**1,463**	1,268
Asset retirement obligation accretion (note 4)	**18**	14	**53**	35
Administration	**38**	32	**115**	89
Stock-based compensation (note 4)	**199**	119	**598**	225
Interest, net	**38**	47	**121**	141
Risk management activities (note 9)	**1,001**	276	**2,301**	576
Foreign exchange gain	**(119)**	(99)	**(121)**	(30)
	2,197	1,281	**5,974**	3,506
Earnings before taxes	**318**	518	**156**	1,316
Taxes other than income tax	**61**	62	**143**	150
Current income tax expense (recovery) (note 5)	**88**	(8)	**228**	122
Future income tax expense (recovery) (note 5)	**18**	153	**(161)**	216
Net earnings (loss)	**$ 151**	$ 311	**$ (54)**	$ 828
Net earnings (loss) per common share (note 8)				
Basic	**$ 0.28**	$ 0.58	**$ (0.10)**	$ 1.54
Diluted	**$ 0.28**	$ 0.57	**$ (0.10)**	$ 1.53

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Nine Months Ended Sep 30 2005	Nine Months Ended Sep 30 2004
Balance – beginning of period	**$ 4,922**	$ 3,650
Net earnings (loss)	**(54)**	828
Dividends on common shares (note 6)	**(94)**	(80)
Purchase of common shares under Normal Course Issuer Bid (note 6)	**(15)**	(26)
Balance – end of period	**$ 4,759**	$ 4,372

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2005	Three Months Ended Sep 30 2004	Nine Months Ended Sep 30 2005	Nine Months Ended Sep 30 2004
Operating activities				
Net earnings (loss)	**$ 151**	$ 311	**$ (54)**	$ 828
Non-cash items				
Depletion, depreciation and amortization	**505**	453	**1,463**	1,268
Asset retirement obligation accretion	**18**	14	**53**	35
Stock-based compensation	**199**	119	**598**	225
Unrealized risk management activities	**633**	105	**1,750**	277
Unrealized foreign exchange gain	**(124)**	(100)	**(108)**	(17)
Deferred petroleum revenue tax recovery	**(14)**	(14)	**(10)**	(13)
Future income tax expense (recovery)	**18**	153	**(161)**	216
Deferred charges	**5**	4	**(33)**	3
Abandonment expenditures	**(19)**	(14)	**(30)**	(27)
Net change in non-cash working capital	**8**	110	**(79)**	(51)
	1,380	1,141	**3,389**	2,744
Financing activities				
(Repayment) issue of bank credit facilities	**(168)**	(138)	**(509)**	743
Issue (repayment) of medium-term notes	**-**	-	**400**	(125)
Repayment of senior unsecured notes	**-**	-	**-**	(54)
Repayment of obligations under capital leases	**-**	-	**-**	(7)
Repayment of preferred securities	**(107)**	-	**(107)**	-
Issue of common shares	**1**	2	**6**	22
Purchase of common shares	**(16)**	(3)	**(16)**	(33)
Dividends on common shares	**(32)**	(27)	**(89)**	(74)
Net change in non-cash working capital	**(4)**	6	**16**	2
	(326)	(160)	**(299)**	474
Investing activities				
Expenditures on property, plant and equipment	**(1,258)**	(861)	**(3,576)**	(3,162)
Net proceeds on sale of property, plant and equipment	**5**	-	**353**	4
Net expenditures on property, plant and equipment	**(1,253)**	(861)	**(3,223)**	(3,158)
Investment in other assets	**71**	-	**11**	-
Net change in non-cash working capital	**109**	(124)	**106**	(152)
	(1,073)	(985)	**(3,106)**	(3,310)
Decrease in cash	**(19)**	(4)	**(16)**	(92)
Cash – beginning of period	**31**	16	**28**	104
Cash – end of period	**$ 12**	$ 12	**$ 12**	$ 12
Interest paid	**$ 61**	$ 54	**$ 152**	$ 150
Taxes paid (recovered)				
Taxes other than income tax	**$ 12**	$ 53	**$ 171**	$ 124
Current income tax	**$ 69**	$ (6)	**$ 192**	$ 57

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, following 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 nine months ended September 30, 2005, pre-tax interest of $45 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

	Sep 30 2005	Dec 31 2004
Risk management (note 9)	**$ -**	$ 104
Deferred charges and other	**109**	76
	109	180
Less: current portion	**-**	72
	$ 109	$ 108

3. LONG–TERM DEBT

		Sep 30 2005		Dec 31 2004
Bank credit facilities				
Bankers' acceptances	$	**48**	$	-
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$218 million)		**302**		306
Preferred securities (2005 – US$ nil, 2004 – US$80 million)		**-**		96
US dollar debt securities (2005 – US$2,200 million, 2004 – US$2,200 million)		**2,554**		2,648
		3,429		3,732
Less: current portion of long-term debt		**194**		194
	$	**3,235**	$	3,538

Bank credit facilities

As at September 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 $24 million were also outstanding at September 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.

In August 2005, the Company filed a short form prospectus that allows for the issue of up to $2 billion of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

Preferred securities

In September 2005, the Company redeemed the US$80 million 8.30% preferred securities due May 25, 2011 for cash consideration of US$91 million, including an early prepayment premium of US$11 million as required under the Note Purchase Agreement.

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

		Sep 30 2005		Dec 31 2004
Asset retirement obligation	**$**	**1,157**	$	1,119
Stock-based compensation		**790**		323
Risk management (note 9)		**1,489**		-
Deferred revenue (note 9)		**11**		26
		3,447		1,468
Less: current portion		**1,877**		260
	$	**1,570**	$	1,208

Asset retirement obligation

At September 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 $3,040 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:

		Nine Months Ended Sep 30, 2005		Year Ended Dec 31, 2004
Asset retirement obligation				
Balance – beginning of period	**$**	**1,119**	$	897
Liabilities incurred		**45**		339
Liabilities settled		**(30)**		(32)
Asset retirement obligation accretion		**53**		51
Revision of estimates		**(1)**		(86)
Foreign exchange		**(29)**		(50)
Balance – end of period	**$**	**1,157**	$	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 recognizes a liability for the expected cash settlements under its Stock 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.

	Nine Months Ended Sep 30, 2005	Year Ended Dec 31, 2004
Stock-based compensation		
Balance – beginning of period	**$ 323**	$ 171
Stock-based compensation provision	**598**	249
Current period payment for options surrendered	**(175)**	(80)
Transferred to common shares	**(20)**	(38)
Capitalized to Horizon Project	**64**	21
Balance – end of period	**790**	323
Less: current portion	**531**	243
	$ 259	$ 80

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2005	Sep 30 2004	**Sep 30 2005**	Sep 30 2004
Current income tax expense (recovery)				
Current income tax – North America	**$ 20**	$ 6	**$ 80**	$ 88
Large corporations tax – North America	**5**	2	**11**	6
Current income tax – North Sea	**57**	(19)	**124**	18
Current income tax – Offshore West Africa	**6**	3	**13**	10
	88	(8)	**228**	122
Future income tax expense (recovery)	**18**	153	**(161)**	216
Income tax expense	**$ 106**	$ 145	**$ 67**	$ 338

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.

During the third quarter of 2005, the Government of British Columbia substantively enacted legislation to reduce its corporate income tax rate by 1.5%, effective July 1, 2005, resulting in a $19 million reduction in the Company's future income tax liability. In the second quarter of 2004, the Government of Alberta substantively enacted legislation to reduce its corporate income tax rate by 1%, effective April 1, 2004, resulting in a $66 million reduction in the Company's future income tax liability. The legislation received royal assent in May 2004.

6. SHARE CAPITAL

Issued Common shares	Nine Months Ended Sep 30, 2005 Number of shares (thousands) [1]		Amount
Balance – beginning of period	**536,361**	**$**	**2,408**
Issued upon exercise of stock options	**656**		**6**
Previously recognized liability on stock options exercised for common shares	**-**		**20**
Purchase of shares under Normal Course Issue Bid	**(300)**		**(1)**
Balance – end of period	**536,717**	**$**	**2,433**

(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 September 30, 2005, the Company had purchased 300,000 common shares at an average price of $53.27 per common share, for a total cost of $16 million. Retained earnings was reduced by $15 million, representing the excess of the purchase price of the common shares over their stated value.

Subsequent to September 30, 2005, the Company purchased an additional 150,000 common shares for a total cost of $7 million.

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

	Nine Months Ended Sep 30, 2005 Stock options (thousands) [1]		Weighted average exercise price [1]
Outstanding – beginning of period	**32,522**	**$**	**12.37**
Granted	**7,429**	**$**	**30.86**
Exercised for common shares	**(656)**	**$**	**9.66**
Surrendered for cash settlement	**(6,429)**	**$**	**10.38**
Forfeited	**(1,340)**	**$**	**18.60**
Outstanding – end of period	**31,526**	**$**	**16.92**
Exercisable – end of period	**8,935**	**$**	**11.00**

(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.

		Sep 30 2005
Balance – beginning of period	**$**	**(6)**
Unrealized gain on translation of net investment		**(15)**
Hedge of net investment with US dollar denominated debt (net of tax)		**10**
Balance – end of period	**$**	**(11)**

8. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
(thousands)	**Sep 30 2005**	Sep 30 2004(1)	**Sep 30 2005**	Sep 30 2004(1)
Weighted average common shares outstanding				
Basic	**536,958**	536,927	**536,688**	536,258
Assumed settlement of preferred securities with common shares(2)	**1,845**	4,620	**-**	5,084
Diluted	**538,803**	541,547	**536,688**	541,342
Net earnings (loss)	**$ 151**	$ 311	**$ (54)**	$ 828
Interest on preferred securities, net of tax(2)	**1**	1	**-**	4
Revaluation of preferred securities, net of tax(2)	**(3)**	(5)	**-**	(2)
Diluted net earnings (loss)	**$ 149**	$ 307	**$ (54)**	$ 830
Net earnings (loss) per common share				
Basic	**$ 0.28**	$ 0.58	**$ (0.10)**	$ 1.54
Diluted	**$ 0.28**	$ 0.57	**$ (0.10)**	$ 1.53

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

(2) Preferred securities are not dilutive for the nine months ended September 30, 2005.

9. FINANCIAL INSTRUMENTS

Risk management

On January 1, 2004, the estimated 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 have been recognized on the consolidated balance sheet and in net earnings. As at September 30, 2005, the estimated fair values of non-designated financial derivatives was comprised as follows:

	Risk management mark-to-market	Deferred revenue
Balance – beginning of period	$ 104	$ (26)
Purchase of put options	172	-
Net change in fair value of financial instruments outstanding as at September 30, 2005	(1,765)	-
Amortization of deferred revenue	-	15
Balance – end of period	(1,489)	(11)
Less: current portion	(1,336)	(10)
	$ (153)	$ (1)

Net unrealized mark-to-market losses for the three months ended September 30, 2005 were $633 million (net unrealized mark-to-market loss of $1,750 million for the nine months ended September 30, 2005).

As at September 30, 2005, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $1,638 million (December 31, 2004 - net unrecognized 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 had the following financial derivatives outstanding as at September 30, 2005:

	Remaining term			Volume	Average price			Index
Crude oil								
Oil price collars	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	Oct 2005	–	Dec 2005	50,000 bbl/d			US$29.81	WTI
	Mar 2006	–	Jul 2006	90,000 bbl/d			US$40.00	WTI
	Aug 2006	–	Dec 2006	84,000 bbl/d			US$45.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$28.00	WTI
	Jan 2007	–	Dec 2007	100,000 bbl/d			US$45.00	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	Oct 2005	–	Dec 2005	1,038,000 GJ/d	C$5.72	–	C$8.55	AECO
	Jan 2006	–	Mar 2006	1,200,000 GJ/d	C$6.09	–	C$11.53	AECO
	Apr 2006	–	Jun 2006	1,093,000 GJ/d	C$5.83	–	C$8.68	AECO
	Jul 2006	–	Sep 2006	825,000 GJ/d	C$5.77	–	C$8.39	AECO
	Oct 2006	–	Dec 2006	344,000 GJ/d	C$6.01	–	C$9.50	AECO

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency swap	Oct 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	Oct 2005	–	Jan 2007	US$200	7.20%	LIBOR(1) + 2.23%
	Oct 2005	–	Oct 2012	US$350	5.45%	LIBOR(1) + 0.81%
	Oct 2005	–	Dec 2014	US$350	4.90%	LIBOR(1) + 0.38%
Swaps – floating to fixed	Oct 2005	–	Mar 2007	C$6	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	$ 49	$ 162	$ 103	$ 79	$ 39	$ 165
Oil transportation and pipeline	$ 3	$ 30	$ 31	$ 70	$ 56	$ 1,033
FPSO operating lease	$ 36	$ 54	$ 51	$ 51	$ 51	$ 222
Baobab Project	$ 5	$ -	$ -	$ -	$ -	$ -
Offshore drilling and other	$ 78	$ -	$ -	$ -	$ -	$ -
Electricity	$ 7	$ 39	$ 41	$ -	$ -	$ -
Office lease	$ 5	$ 20	$ 20	$ 19	$ 20	$ 29
Processing	$ 1	$ 2	$ -	$ -	$ -	$ -

During the third quarter of 2005, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future Horizon crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. Annual toll payments before operating costs will be approximately $35 million.

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 is expected to be $6.8 billion, including a contingency fund of $700 million, with $1.4 billion to be incurred in 2005, $2.6 billion to be incurred in 2006 and $2.8 billion to be incurred in 2007 and 2008.

11. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore West Africa			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**2,293**	1,604	**5,556**	4,432	**513**	403	**1,288**	959	**104**	61	**205**	167
Less: royalties	**(399)**	(273)	**(937)**	(749)	**(1)**	(1)	**(2)**	(2)	**(3)**	(2)	**(6)**	(5)
Revenue, net of royalties	**1,894**	1,331	**4,619**	3,683	**512**	402	**1,286**	957	**101**	59	**199**	162
Segmented expenses												
Production	**326**	257	**889**	717	**106**	104	**311**	266	**10**	9	**27**	27
Transportation	**75**	63	**215**	182	**5**	10	**16**	25	**-**	-	**-**	-
Depletion, depreciation and amortization	**403**	365	**1,183**	1,037	**82**	74	**236**	184	**18**	12	**38**	42
Asset retirement obligation accretion	**9**	7	**25**	21	**9**	7	**28**	14	**-**	-	**-**	-
Realized risk management activities	**303**	130	**438**	228	**65**	41	**113**	71	**-**	-	**-**	-
Total segmented expenses	**1,116**	822	**2,750**	2,185	**267**	236	**704**	560	**28**	21	**65**	69
Segmented earnings before the following	**778**	509	**1,869**	1,498	**245**	166	**582**	397	**73**	38	**134**	93
Non-segmented expenses												
Administration												
Stock-based compensation												
Interest, net												
Unrealized risk management activities												
Foreign exchange gain												
Total non-segmented expenses												
Earnings (loss) before taxes												
Taxes other than income tax												
Current income tax expense (recovery)												
Future income tax expense (recovery)												
Net earnings (loss)												

(millions of Canadian dollars, unaudited)	Midstream Three Months Ended Sep 30		Midstream Nine Months Ended Sep 30		Other Three Months Ended Sep 30		Other Nine Months Ended Sep 30	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**18**	17	**56**	50	**-**	-	**-**	-
Less: royalties	**-**	-	**-**	-	**-**	-	-	-
Revenue, net of royalties	**18**	17	**56**	50	-	-	-	-
Segmented expenses								
Production	**5**	6	**16**	15	**-**	-	**-**	-
Transportation	**-**	-	**-**	-	**-**	-	**-**	-
Depletion, depreciation and amortization	**2**	2	**6**	5	**-**	-	**-**	-
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-
Total segmented expenses	**7**	8	**22**	20	**-**	-	**-**	-
Segmented earnings before the following	**11**	9	**34**	30	-	-	-	-
Non-segmented expenses								
Administration								
Stock-based compensation								
Interest, net								
Unrealized risk management activities								
Foreign exchange gain								
Total non-segmented expenses								
Earnings (loss) before taxes								
Taxes other than income tax								
Current income tax expense (recovery)								
Future income tax expense (recovery)								
Net earnings (loss)								

(millions of Canadian dollars, unaudited)	Inter-segment Elimination Three Months Ended Sep 30		Inter-segment Elimination Nine Months Ended Sep 30		Total Three Months Ended Sep 30		Total Nine Months Ended Sep 30	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**(10)**	(10)	**(30)**	(30)	**2,918**	2,075	**7,075**	5,578
Less: royalties	**-**	-	**-**	-	**(403)**	(276)	**(945)**	(756)
Revenue, net of royalties	**(10)**	(10)	**(30)**	(30)	**2,515**	1,799	**6,130**	4,822
Segmented expenses								
Production	**(1)**	-	**(3)**	(2)	**446**	376	**1,240**	1,023
Transportation	**(9)**	(10)	**(27)**	(28)	**71**	63	**204**	179
Depletion, depreciation and amortization	**-**	-	**-**	-	**505**	453	**1,463**	1,268
Asset retirement obligation accretion	**-**	-	**-**	-	**18**	14	**53**	35
Realized risk management activities	**-**	-	**-**	-	**368**	171	**551**	299
Total segmented expenses	**(10)**	(10)	**(30)**	(30)	**1,408**	1,077	**3,511**	2,804
Segmented earnings before the following	**-**	-	**-**	-	**1,107**	722	**2,619**	2,018
Non-segmented expenses								
Administration					**38**	32	**115**	89
Stock-based compensation					**199**	119	**598**	225
Interest, net					**38**	47	**121**	141
Unrealized risk management activities					**633**	105	**1,750**	277
Foreign exchange gain					**(119)**	(99)	**(121)**	(30)
Total non-segmented expenses					**789**	204	**2,463**	702
Earnings (loss) before taxes					**318**	518	**156**	1,316
Taxes other than income tax					**61**	62	**143**	150
Current income tax expense (recovery)					**88**	(8)	**228**	122
Future income tax expense (recovery)					**18**	153	**(161)**	216
Net earnings (loss)					**151**	311	**(54)**	828

Net additions to property, plant and equipment

	Nine Months Ended	
	Sep 30 2005	Sep 30 2004
North America	**$ 1,562**	$ 2,386
North Sea	**268**	536
Offshore West Africa	**351**	185
Other	**5**	-
Horizon Oil Sands Project	**942**	233
Midstream	**3**	5
Head office	**16**	27
	$ 3,147	$ 3,372

	Property, plant and equipment		Total assets	
	Sep 30 2005	Dec 31 2004	**Sep 30 2005**	Dec 31 2004
Segmented assets				
North America	**$ 13,780**	$ 13,394	**$ 15,460**	$ 14,428
North Sea	**1,779**	1,823	**2,147**	2,036
Offshore West Africa	**1,204**	901	**1,290**	914
Other	**13**	8	**41**	35
Horizon Oil Sands Project	**1,614**	672	**1,660**	672
Midstream	**206**	209	**282**	268
Head office	**64**	57	**64**	57
	$ 18,660	$ 17,064	**$ 20,944**	$ 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 September 30, 2005:

Interest coverage (times)	
Net earnings[1]	4.7x
Cash flow from operations[2]	22.7x

(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 &
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Réal M. Cusson*
Senior Vice-President, Marketing

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

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

Lyle G. Stevens*
Senior Vice-President, Exploitation

Jeff W. Wilson*
Senior Vice-President, Exploration

Mary-Jo E. Case*
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Vice-President, Investor Relations

Wayne M. Chorney
Vice-President, Development Operations

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Vice-President, Regulatory, Stakeholder &
Environmental Affairs

Gordon M. Coveney
Vice-President, Exploration - East

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

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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

International Operations

CNR International (U.K.) Limited

Martin Cole*
Vice-President & Managing Director

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

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