

Canadian Natural

Press Release

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES RECORD QUARTERLY PRODUCTION, EARNINGS AND CASH FLOW

CALGARY, ALBERTA – FEBRUARY 23, 2006 – FOR IMMEDIATE RELEASE

“In looking back at 2005, it was another exceptionally productive year” commented Allan Markin, Chairman of the Company. “In examining the conventional side of the business and our four per-share business metrics, production and proved and probable reserves increased 8% over 2004, while cash flow increased by 33% and the discounted value of our conventional reserves and undeveloped land less net debt increased by 82%. Over and above the conventional side of the business, we sanctioned the Horizon Oil Sands Project (“Horizon Project”) in early 2005 and based on an independent engineer evaluation booked 3.4 billion barrels of gross proved and probable bitumen reserves, obtained lump sum bids on a substantial portion of Phase 1 construction costs and completed 19% of the construction effort. The Horizon Project will add significant value for shareholders with commissioning targeted for the second half of 2008. Financially, we reduced long term debt by approximately $400 million even though we incurred about $1.3 billion on the Horizon Project. This left our debt to book capitalization at only 29%, or 5 percentage points better than where we entered the year. In short, we have been able to deliver on a major development project and still maintain the diligence to deliver on our base conventional business. This is a testament to our management systems, empowered corporate culture and our team’s major project management skills.”

“As we look forward to 2006, we are equally excited” he continued. “Our ongoing exploitation programs in North America and the North Sea are solid contributors to growth and value while our new development projects at West Espoir and North Primrose will be major drivers in 2006. In addition, in 2006 we target to have 55% to 63% of the construction effort on Phase 1 of the Horizon Project completed along with the scoping study for our new in-situ upgrader. We are poised to continue solid growth well into the next decade with a clearly defined growth strategy.”

“Balance sheet strength and the continued application of our disciplined approach to business will enable Canadian Natural to make the most of its opportunities” added John Langille, Vice Chairman. “Our long term financial strategies will allow us to deliver major projects such as the Horizon Project and the Canadian Natural upgrader even in a lower oil price environment. This ensures that we do not have to compromise on our capital allocation. The team that we have assembled and the core competencies that we have developed provide us with the necessary technical, operational, and financial expertise to deliver these larger and more complex projects.”

Canadian Natural’s President and Chief Operating Officer, Steve Laut, in commenting on the Company’s net proved reserves stated “The year 2005 was a challenging year in terms of managing both the impacts of unusual weather patterns on the drilling program and general cost pressures in a heated business environment. Canadian Natural performed very well on the conventional business. Crude oil production volumes increased by 11% while natural gas volumes in North American grew by 6% from 2004 levels. We replaced 145% of production with finding and onstream costs at $13.41 per barrel of oil equivalent. Many of these challenges continue in 2006, however, we will leverage our strong asset base and extensive infrastructure in order to mitigate these pressures to the full extent possible.”

HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Dec 31 2005	Sep 30 2005	Dec 31 2004	Year Ended Dec 31 2005	Dec 31 2004
Net earnings	**$ 1,104**	$ 151	$ 577	**$ 1,050**	$ 1,405
per common share, basic (1)	**$ 2.06**	$ 0.28	$ 1.07	**$ 1.96**	$ 2.62
Adjusted net earnings from operations (2)	**$ 601**	$ 593	$ 321	**$ 2,034**	$ 1,405
per common share, basic (1)	**$ 1.12**	$ 1.10	$ 0.60	**$ 3.79**	$ 2.62
Cash flow from operations (3)	**$ 1,490**	$ 1,386	$ 950	**$ 5,021**	$ 3,769
per common share, basic (1)	**$ 2.78**	$ 2.58	$ 1.77	**$ 9.36**	$ 7.03
Capital expenditures, net of dispositions	**$ 1,679**	$ 1,272	$ 1,421	**$ 4,932**	$ 4,633
Debt to book capitalization (4)	**29%**	32%	34%	**29%**	34%
Daily production, before royalties					
Natural gas (mmcf/d)	**1,423**	1,423	1,410	**1,439**	1,388
Crude oil and NGLs (bbl/d)	**340,268**	334,724	295,704	**313,168**	282,489
Equivalent production (boe/d)	**577,505**	571,911	530,745	**552,960**	513,835

(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 Management's Discussion and Analysis ("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 quarterly cash flow of $1.5 billion, a 57% improvement over Q4/04 and an 8% improvement over Q3/05.
- Record annual cash flow in 2005 of $5.0 billion, a 33% increase over the $3.8 billion recorded in 2004.
- Record quarterly net earnings of $1.1 billion up 91% from Q4/04. Fourth quarter net earnings included:
  - Gain of $583 million after tax for the change in the unrealized mark-to-market of the Company's non-designated commodity hedge position. For the full year 2005, a charge of $607 million after tax was incurred, effectively recognizing commodity strip price strength at December 31 for hedged production for future years into current results.
  - Charge of $75 million after tax for revaluation of stock option liability to reflect stock price appreciation during the quarter.
- Record quarterly adjusted net earnings from operations of $601 million, representing a 87% increase over Q4/04.
- Record 2005 annual adjusted net earnings from operations accumulated to $2.0 billion, a 45% increase over 2004.
- Exceptionally strong balance sheet with debt to book capitalization exiting at 29% and debt to EBITDA at 0.6x compared with 34% and 1.0x at the end of 2004, respectively. This was achieved despite $1.3 billion incurred in construction costs for the Horizon Oil Sands Project ("Horizon Project").
- Record quarterly production volumes, 9% higher than Q4/04 and 5.6 mboe/d higher than Q3/05. Quarterly natural gas production represents 41% of equivalent production and 50% of North American equivalent production.
- Strong North American natural gas production with Q4/05 increasing 3% over Q4/04. Full year 2005 volumes increased 6% over 2004 levels.

- Completed a significant fourth quarter drilling program of 492 net wells, excluding stratigraphic test and service wells, with a 95% success ratio, reflecting Canadian Natural's strong, predictable, low risk asset base.
- Used independent qualified reserve evaluators to determine 100% of the Company's conventional crude oil and natural gas reserves under constant prices and costs as at December 31, 2005:
  - Total net proved reserves, from conventional operations at the end of 2005 amounted to 1.1 billion barrels of crude oil and NGLs and 2.8 trillion cubic feet of natural gas with net proved and probable reserves of 1.7 billion barrels of crude oil and NGLs and 3.7 trillion cubic feet of natural gas. Thermal oil sands net proved reserves remained relatively flat with the prior year, as higher field reserves were offset by higher future royalties.
  - Net proved reserve additions from conventional operations equaled 145% of 2005 net production, at a finding and onstream cost of $13.41 per barrel of oil equivalent. The Company's three year average proved finding and onstream costs were $12.55 per barrel of oil equivalent.
  - Net proved and probable reserve additions from conventional operations equaled 195% of 2005 net production, at a finding and onstream cost of $9.97 per barrel of oil equivalent. The Company's three year average net proved and probable finding and onstream costs were $8.05 per barrel of oil equivalent.
  - North American net proved reserve additions equaled 152% of 2005 net production at a finding and onstream cost of $12.04 per barrel of oil equivalent, down 22% from 2004 and 13% from the three-year average of $13.77 per barrel of oil equivalent. Proved reserve additions in North America were comprised of 0.6 trillion cubic feet of natural gas and 117 million barrels of crude oil and NGLs.
  - Using net proved and probable finding and onstream costs the Company achieved an overall recycle ratio of 3.4 (2.5 using only proved reserve additions) during 2005.
- Used independent qualified reserve evaluators to determine 100% of the Company's Phase 1 to 3 oil sands mining reserves for the Horizon Project under constant prices as at December 31, 2005 resulted in 2.2 billion barrels of gross proved bitumen reserves and 3.4 billion barrels of gross proved and probable bitumen reserves. This represents an increase from the February 9, 2005 evaluation of 1.9 billion barrels of gross proved bitumen reserves and 3.3 billion barrels of gross proved and probable bitumen reserves.
- Continued strong undeveloped conventional land base in Canada of 10.8 million net acres – a key asset in today's highly competitive industry. Total developed and undeveloped land holdings in Canada increased slightly from 16.4 million net acres in 2004 to 16.6 million net acres in 2005.
- Continued production improvements in Pelican Lake arising from new drilling and expansion of enhanced oil recovery strategies. Pelican Lake crude oil production averaged 28 mbbl/d during the quarter up 3 mbbl/d from Q3/05, representing the strongest quarter of production achieved from the field since Q4/02.
- Successfully installed the wellhead tower on the West Espoir Field located offshore Côte d'Ivoire. This development continues on time and on budget with first oil targeted for the second half of 2006.
- Filed the Development Plan for the Olowi Field with the Government of Gabon in Q4/05. Approvals for this offshore crude oil development were subsequently received in early 2006.
- Horizon Project remained on budget and moved slightly ahead of schedule with site preparation and construction work benefiting from a warmer and drier than normal fourth quarter.
- Sixth straight year of dividend increases. The 2006 quarterly dividends will increase 25% from $0.06 per common share to $0.075 per common share commencing with the April 1, 2006 dividend payment.

CORPORATE UPDATE

Canadian Natural is pleased to announce that the Honourable Gary A. Filmon, P. C., O. M. has been appointed a member of the Board of Directors of the Company. He has had a long and distinguished career serving in public office, first as Winnipeg City Councilor for four years followed by over 20 years as a Member of the Legislative Assembly of Manitoba. During that time he was Premier of the Province of Manitoba and Leader of the Manitoba Progressive Conservative Party. The Honourable Gary A. Filmon has a Masters Degree in Civil Engineering and currently serves on a number of corporate and public boards.

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. Further, the Company maintains 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. A large diversified project portfolio facilitates the effective allocation of capital to higher return opportunities.

Activity by core region

	Net undeveloped land as at Dec 31, 2005 (thousands of net acres)	Drilling activity Year ended Dec 31, 2005 (net wells)
Canadian conventional		
Northeast British Columbia	**2,027**	**241**
Northwest Alberta	**1,507**	**183**
Northern Plains	**6,594**	**907**
Southern Plains	**621**	**354**
Southeast Saskatchewan	**82**	**52**
	10,831	**1,737**
Horizon Oil Sands Project	**116**	**126**
United Kingdom North Sea	**352**	**14**
Offshore West Africa	**426**	**5**
	11,725	**1,882**

Drilling activity (number of wells)

	Year Ended Dec 31			
	2005		2004	
	Gross	**Net**	Gross	Net
Crude oil	**685**	**627**	378	328
Natural gas	**1,071**	**890**	801	689
Dry	**136**	**117**	106	96
Subtotal	**1,892**	**1,634**	1,285	1,113
Stratigraphic test / service wells	**251**	**248**	339	336
Total	**2,143**	**1,882**	1,624	1,449
Success rate (excluding stratigraphic test / service wells)		**93%**		91%

North American natural gas

	Quarterly Results			Year End Results	
	Q4/05	Q3/05	Q4/04	**2005**	2004
Natural gas production (mmcf/d)	**1,402**	1,400	1,365	**1,416**	1,330
Net wells targeting natural gas	**295**	226	162	**975**	773
Net successful wells drilled	**279**	213	152	**890**	689
Success rate	**95%**	94%	94%	**91%**	89%

- Q4/05 natural gas production represented a 3% increase over the previous year despite much wetter than normal weather during the critical spring tie-in season and in Q3/05. During the fourth quarter, a strong start to the winter drilling season was tempered by a warmer than normal December delaying freeze up for winter activities. A total of 346 wells were expected to be drilled during Q4/05 and only 295 were actually drilled.
- High success rates reflect Canadian Natural's low-risk exploitation approach and high quality land base. The Q4/05 drilling program represented an active program across the Company's core regions. In Northeast British Columbia 30 net wells targeting natural gas were drilled, while in Northwest Alberta 56 net wells were drilled, including 29 Cardium targets. In Northern and Southern Plains, a combined 59 coal bed methane, 97 shallow natural gas and 53 conventional net wells were drilled.
- Warmer than normal weather has continued into 2006, as such the Company is leveraging its deep drilling inventory and optimizing drilling plans to adjust for road bans and/or site access issues. Despite these challenges Canadian Natural still expects to complete the majority of its winter drilling program. However, the risk remains for an early spring break up which could significantly delay tie-ins of many of these new wells.

North American crude oil and NGLs

	Quarterly Results			Year End Results	
	Q4/05	Q3/05	Q4/04	**2005**	2004
Crude oil and NGLs production (bbl/d)	**230,263**	231,260	214,493	**221,669**	206,225
Net wells targeting crude oil	**191**	184	107	**642**	326
Net successful wells drilled	**185**	175	105	**612**	317
Success rate	**97%**	95%	98%	**95%**	97%

- Q4/05 crude oil drilling activity represented an all time quarterly record and included 124 net wells targeting heavy crude oil in the Northern Plains core region. During 2005, conventional heavy crude oil drilling increased by 160 net wells from 2004 levels with 340 net wells being completed. This was reflected in associated production volumes which increased from 92 mbbl/d in Q1/05 to over 96 mbbl/d in Q4/05.
- The Primrose Field development continued with the drilling of 19 new net wells in Q4/05. 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 Q4/05 were 8 mbbl/d or 13% lower than Q3/05 but still 4.4 mbbl/d better than originally anticipated. Volumes are expected to reduce in Q1/06 due to continued steam cycles, however volumes will benefit following commencement of production from Primrose North. Overall, the new Primrose pads continue to produce at rates approximately 17% better than expected while project development continues on plan.
- The Primrose North expansion plans continue on schedule and on budget. Crude oil production from the first pad commenced in January 2006 with production forecast to ramp to approximately 30 mbbl/d by Q3/2006.

- The Pelican Lake waterflood expansion project continues to move ahead. Three pads comprising 12 new producing net wells were brought on line in Q4/05, and production response continues to exceed expectations. Field-wide, 27 net additional producing wells initiated production in Q4/05, resulting in production levels increasing by 2.7 mbbl/d or 11% over Q3/05. This represents the highest production levels from this field since Q4/02.
- Initial behavior of the polymer flood pilot test at Pelican Lake has been positive, however definitive conclusions regarding the feasibility of the program will not be known until late 2006 or early 2007. In advance of pilot results, preparations for commercial polymer flood have commenced including source water development and advance ordering of some of the long lead time equipment.

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			Year End Results	
	Q4/05	Q3/05	Q4/04	**2005**	2004
Total crude oil production (bbl/d)					
North Sea	**66,798**	73,543	69,971	**68,593**	64,706
Offshore West Africa	**43,207**	29,921	11,240	**22,906**	11,558
Total natural gas production (mmcf/d)					
North Sea	**15**	18	40	**19**	50
Offshore West Africa	**6**	5	5	**4**	8
Net wells targeting crude oil	**5.9**	4.3	4.0	**17.3**	14.1
Net successful wells drilled	**5.0**	4.3	2.3	**15.0**	11.4
Success rate	**85%**	100%	58%	**87%**	81%

North Sea

- Canadian Natural continues to execute its exploitation strategy in the North Sea. The first stage of this exploitation program is based upon optimizing existing facilities and waterfloods. Canadian Natural continues to effect this first stage of exploitation on its holdings in the North Sea. The second stage of exploitation incorporates more near pool development and exploration in order to maximize utilization of the common facilities and ultimately extend all fields' economic lives. In 2006 and beyond, increasing emphasis on this type of work is evidenced by the ongoing development at the Columba Terraces and the Lyell Field.
- During Q4/05, 5.3 net wells were drilled with an additional 2.9 net wells drilling at quarter end. Production levels were in line with expectations and reflected expected curtailments at the Lyell Field and the Columba B and E Terraces as well as continued restrictions at Murchison due to third party natural gas export facilities and normally expected production declines at the satellite Playfair well. A new well drilled into the Columba D Terrace in late October produced at an average rate of 7 mbbl/d net to Canadian Natural for the remainder of the quarter.
- On the T-Block, at Tiffany, the platform rig completed a successful third party well and tariff income for processing was received. Following this, the first new Tiffany well (100% owned and operated by Canadian Natural) was drilled. In addition, on Thelma the first of two sub-sea wells targeting unswept areas of the field was drilled and completed.
- Construction of the subsea water injection pump at Columba E progressed during the quarter. This will be tied into 2 additional subsea water injection wells that will be drilled in 2006. This repressurization of the pool, combined with artificial lift will result in increased productive capacity from the existing long reach wells.
- Plans for the further development of Lyell progressed, comprising the drilling of 4 net wells and workovers at 2 existing net wells in 2006/7. At its plateau, new production of approximately 20 mboe/d is forecast from this Field.

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). Peak crude oil reached 62 mbbl/d (38 mmbbl/d net to Canadian Natural) during the quarter and averaged 28 mbbl/d net to Canadian Natural. The eighth producer well has experienced production restrictions due to limitations resulting from monitoring sand screen effectiveness. Upon completion of drilling of further wells in early 2006, production levels are forecast at 35 mbbl/d net to Canadian Natural.
- Net production at East Espoir increased by 2 mbbl/d from Q3/05 levels and averaged 16 mboe/d during Q4/05 following the build-up of production from the infill drilling program. The infill drilling program consists of four wells, with two wells now completed and the remaining two wells to be completed in early 2006.
- During the quarter, the West Espoir drilling tower, which will facilitate development drilling of this reservoir, was installed on location and the drilling conductors were driven to depth. The project continues on time and on budget with first crude oil production expected in the second half of 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 90% 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 potentially contains as much as 500 million barrels of 34º API light crude original oil in place. The crude oil reservoir is overlain by a large gas cap with potentially 1 trillion cubic feet of original gas in place. A development plan comprising an Floating Production Storage and Offtake Vessel and four drilling towers was filed with Government in late 2005 and was approved for execution in early 2006. The development will commence in late 2006 with first production targeted for late 2008 to reach a plateau of 20 mbbl/d.

Horizon Oil Sands Project

- The 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 were completed, 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 (targeted at 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.
- Construction capital costs for Phase 1 of the Horizon Project are estimated at, including a contingency fund of $700 million, $6.8 billion with $1.3 billion spent in 2005, $2.6 billion forecast to be incurred in 2006 and $2.9 billion forecast to be incurred in 2007 and 2008 combined. Total targeted capital costs for all three phases of the development are projected to be $10.8 billion.
- The quarterly update for the project is as follows:

Project status summary	**Dec 31, 2005**		Mar 31, 2006
	Actual	Plan	Plan
Phase 1 - Work progress (cumulative)	**19%**	16%	22%
Phase 1 - Construction capital spending (cumulative)	**19%**	20%	29%

Accomplished During the Fourth Quarter

Detailed Engineering

- All project areas met their staffing requirements and overall progress for detailed engineering is on schedule.
- 3-D engineering design models are well advanced in most areas with some plant areas at the 90% model review stage.
- Hazard and Operability reviews were completed and findings have been incorporated into the plant designs.

Procurement

- Total procurement progress is at C$3.8 billion in awarded contracts and purchase orders, with a further C$600 million in various stages of the tender process.
- Key purchase orders were awarded for various mechanical equipment (pumps and valves), fabricated pipe and steel.
- Several contracts were awarded for piling, foundations and miscellaneous earthworks.

Modularization

- Module fabrication and assembly maintained schedule.
- Module transportation remains on schedule, in an environment of key transportation restrictions. A total of 88 oversized loads were transported to site by year end.

Construction

- As a direct result of Management's strong endorsement of safety awareness, on-site safety statistics and performance improved for the eleventh month in a row and are well below the Company's targets, benchmarked against other projects in the area.
- Mine overburden removal is 10% ahead of plan, with a total of 6.7 million bank cubic meters of material removed.
- Critical path underground piping was completed, prior to winter weather conditions.
- Completed expansion of Camp 1 to 2,000 people from 1,500.
- Progress on the second of three (2,000 person) camps is 72% complete.
- Coker foundations are complete and ready for Coke Drum installation by mid 2006.
- Earthwork for the raw water and recycle water pond systems commenced as scheduled.
- Naphtha Reactor, fabricated in India, arrived in the Fort McMurray staging area as scheduled.
- Extraction Separation Cell foundations were completed.
- Erection of the Separation Cells was started with over 80% of required materials on site.
- The Shop maintenance building was completed and ready for occupancy and the turnover of the Emergency Medical Services buildings to construction unit was completed. Turnover of the Fire Hall was deferred until February 1.

First Quarter 2006 Milestones

- Detailed engineering targeted to have completed at least 60% model reviews in all areas.
- Target the total awarded contracts and purchase orders to achieve C$4 billion.
- Complete transport of all four Coke Drums to plant site.
- Complete transport of Naphtha Reactor to site from staging area.
- Delivery of oversized loads to site targeted to reach 250.

MARKETING

	Quarterly Results			Year End Results	
	Q4/05	Q3/05	Q4/04	**2005**	2004
Crude oil and NGLs pricing					
WTI[1] benchmark price (US$/bbl)	**$ 60.04**	$ 63.17	$ 48.27	**$ 56.61**	$ 41.43
Lloyd Blend Heavy oil differential from WTI (%)	**40%**	30%	41%	**37%**	32%
Corporate average pricing before risk management (C$/bbl)	**$ 46.38**	$ 57.35	$ 36.92	**$ 46.86**	$ 37.99
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 11.07**	$ 7.73	$ 6.71	**$ 8.05**	$ 6.43
Corporate average pricing before risk management (C$/mcf)	**$ 11.67**	$ 8.61	$ 6.77	**$ 8.57**	$ 6.50

(1) Refers to West Texas Intermediate crude oil barrel priced at Cushing, Oklahoma.

- Heavy crude oil differentials widened to approximately 40% during the fourth quarter, reflecting both the winter seasonal decline in demand for heavy crude oil as well as a increased demand for lighter barrels of crude oil which widens this differential. Following hurricanes Katrina and Rita, U.S. refiners sought to process lighter barrels to increase their yields of gasoline and distillates to meet market requirements. This demand for light barrels increases prices for benchmark light crude oils such as WTI, but does not necessarily translate into higher demand and prices for heavier crude oils, thereby widening the differential.
- During the fourth quarter, the Company blended approximately 139 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 pressure tested for operation with first shipments expected in late Q1/06.
- The Scoping Study for the Canadian Natural Upgrader was initiated during the quarter. The terms of reference for this study will evaluate end product alternatives, location, technology, gasification and integration with existing assets. It is expected to provide recommendations in late 2006 / early 2007 and will be the first stage of front end loading for the project – following the same disciplined approach utilized in the Horizon Project. Following this Study, the Design Basis Memorandum and Engineering Design Specification will be completed prior to construction.

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 and other major projects. A brief summary of its strengths are:
  - A diverse asset base geographically and by product - currently producing in excess of 577 mboe/d, comprised of approximately 41% natural gas and 59% crude oil - with 92% 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 $3.3 billion of unused bank lines available at December 31, 2005.
  - Strong balance sheet – with a debt to book capitalization ratio of 29%, debt to cash flow of 0.7x, debt to EBITDA of 0.6x and shareholders’ equity of $8.2 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 as well as the Horizon Project and the value-adding Canadian Natural upgrader.
- In January 2005, the Board of Directors authorized the expansion of the Company's commodity 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 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 budgeted 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 60% of budgeted 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 December 31, 2005, the implied price differentials for the non-designated hedges 2006 and future years. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $925 million ($607 million after tax) unrealized loss on its risk management activities for 2005, including an $825 million ($583 million after tax) unrealized gain for the three months ended December 31, 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.
- During Q4/05, Canadian Natural utilized its Normal Course Issuer Bid ("NCIB") program administered through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") in order to repurchase and cancel 550,000 common shares for a total cost of C$30.7 million (C$55.82 per common share). For the year ended December 31, 2005, a total of 850,000 common shares were repurchased under these facilities. On January 20, 2006, the NCIB was renewed through January 27, 2007. To date in 2006, no common shares have been repurchased under this facility.
- In January 2006, Canadian Natural issued C$400 million of 7-year notes at a rate of 4.50%
- In February 2006, the Board of Directors approved an increase in the quarterly dividend to $0.075 per common share from $0.06 per common share. The 25% increase recognizes the stability of Canadian Natural's cash flow and provides a further return to shareholders. This is the sixth consecutive year in which the Company has paid a dividend and the fifth consecutive year of increase in the distribution paid to its shareholders. The increased dividend will become effective with the quarterly payment to be paid on April 1, 2006.

Q1/06 OUTLOOK

The Company currently expects 2006 production levels before royalties to average 1,468 to 1,551 mmcf/d of natural gas and 335 to 373 mbbl/d of crude oil and NGLs. Q1/06 production guidance before royalties is 1,426 to 1,475 mmcf/d of natural gas and 306 to 334 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.

YEAR-END RESERVES

Determination of reserves

- For the year ended December 31, 2005, Canadian Natural retained qualified independent reserve evaluators, Sproule Associates Limited ("Sproule"), and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's conventional proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Sproule evaluated the Company's North American assets and Ryder Scott evaluated its international assets. Canadian Natural has been granted an exemption from the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as related 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 however, 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 SEC requires that oil sands mining reserves be disclosed separately from conventional oil and gas disclosure. Canadian Natural retained a qualified independent reserve evaluator, Gilbert Laustsen Jung Associates Limited ("GLJ"), to evaluate the Company's Horizon Project. Adhering to SEC Industry Guide 7 requirements, the gross proved bitumen reserves as of December 31, 2005 under constant prices were 2.2 billion barrels. The gross proved and probable bitumen reserves were 3.4 billion barrels.
- The Board of Directors of the Company has a Reserves Committee, which has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ as to the Company's reserves.

North America Conventional Net Reserves

- Natural gas proved reserves increased by 6% replacing 137% of 2005 production. Similarly, crude oil and NGLs proved reserves increased by 7%, replacing 167% of production. This was accomplished at an all-in finding and onstream cost of $12.04 per barrel of oil equivalent, down 22% from 2004 reflecting Canadian Natural's strong asset base and ability to control costs in a highly inflationary environment. Thermal oil sands proved reserves remained relatively flat with the prior year at 387 million barrels, with no thermal reserves being added or removed as a result of year end pricing.

International Conventional Net Reserves

- North Sea proved reserves remained relatively flat at 295 million barrels of oil equivalent or about 19% of total proved reserves. Reserve additions were primarily achieved through optimization of waterflood design, infill drilling program and recompletions.
- Offshore West Africa proved reserves increased by 15% through the developments at Espoir and Baobab Fields in Côte d'Ivoire as well as the acquisition of the Olowi Field in Gabon. Offsetting some of the increased field reserves on these projects were higher calculated Government take under the various production sharing contracts and agreements. Generally, the Company receives a greater portion of production until capital development costs are recouped whereupon government portion of revenue substantially increases. With the current high world crude oil price, these projects generally require fewer of the reserves to cover payout of capital costs, thereby reducing the reserves ultimately allocated to the Company over the field life.

Conventional Proved Undeveloped Net Reserves (PUDs)

- In the Evaluation Reports, 38% of crude oil proved reserves are assigned to the proved undeveloped category. This is a reduction from the 43% recorded in 2004 following the successful development of the Baobab Field and portions of the Primrose Field. Of these 2005 reserves, 55% are associated with our Primrose thermal oil sands project where extensive pool delineation and geological analysis is required to justify continued development and expansion of the project. A further 15 million barrels is included from the Olowi Field recently acquired in Offshore Gabon where engineering design has commenced with first crude oil production expected in late 2008.
- In the Evaluation Reports, 18% of natural gas proved reserves are assigned to the proved undeveloped category reflecting the generally shorter lead times required for natural gas developments in Canada.

Conventional Proved and Probable Net Reserves

- In the Evaluation Reports, total proved and probable reserves increased by 8%, driven largely by the 10% increase in North America where approximately 76 million barrels of oil equivalent of thermal in-situ proved and probable reserves were added.

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2005			
	Proved Developed[2]	**Proved Undeveloped[2]**	**Proved Total [2]**	**Proved and Probable[3]**
Crude oil & NGLs (mmbbl)				
North America	**402**	**292**	**694**	**1,035**
North Sea	**214**	**76**	**290**	**417**
Offshore West Africa	**80**	**54**	**134**	**206**
	696	**422**	**1,118**	**1,658**
Natural gas (bcf)				
North America	**2,300**	**441**	**2,741**	**3,548**
North Sea	**16**	**13**	**29**	**69**
Offshore West Africa	**10**	**62**	**72**	**110**
	2,326	**516**	**2,842**	**3,727**
Total reserves (mmboe)	**1,083**	**509**	**1,592**	**2,279**
Reserve replacement ratio[4] (%)			**145%**	**195%**
Cost to develop[5] ($/boe)				
10% discount	**0.79**	**5.69**	**2.36**	**2.55**
15% discount	**0.67**	**5.15**	**2.11**	**2.25**
Present value of conventional reserves[6] ($ millions)				
10% discount	**24,275**	**6,342**	**30,617**	**38,682**
15% discount	**20,939**	**4,881**	**25,820**	**31,642**

RESERVES OF CONVENTIONAL CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES[1]

	December 31, 2004			
	Proved Developed[2]	Proved Undeveloped[2]	Proved Total [2]	Proved and Probable[3]
Crude oil & NGLs (mmbbl)				
North America	367	281	648	926
North Sea	218	85	303	415
Offshore West Africa	20	95	115	196
	605	461	1,066	1,537
Natural gas (bcf)				
North America	2,213	378	2,591	3,319
North Sea	12	15	27	57
Offshore West Africa	5	67	72	90
	2,230	460	2,690	3,466
Total reserves (mmboe)	976	538	1,514	2,115
Reserve replacement ratio[4] (%)			220%	281%
Cost to develop[5] ($/boe)				
10% discount	0.85	3.58	1.77	1.78
15% discount	0.73	3.27	1.58	1.56
Present value of conventional reserves[6] ($ millions)				
10% discount	13,739	4,399	18,138	22,937
15% discount	11,838	3,440	15,279	18,802

OIL SANDS MINING RESERVES[1](7)

The following table sets out Canadian Natural's reserves of bitumen and synthetic crude oil from the Horizon Project Oil Sands leases as of December 31, 2005.

	Dec 31, 2005		Feb 9, 2005	
	Proved Total	Proved and Probable	Proved Total	Proved and Probable
Gross reserves, before royalties (mmbbl)				
Bitumen	2,235	3,430	1,900	3,320
Synthetic crude oil*	1,833	2,878	1,560	2,790

**Synthetic crude oil reserves are based upon upgrading of the bitumen reserves. The reserves shown for bitumen and synthetic crude oil are not additive.*

CONVENTIONAL CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES[1]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (mmbbl)				
Reserves, December 31, 2003	**588**	**222**	**85**	**895**
Extensions & discoveries	17	-	-	17
Infill drilling	24	35	-	59
Improved recovery	1	10	-	11
Property purchases	36	38	-	74
Property disposals	-	-	-	-
Production	(66)	(24)	(4)	(94)
Revisions of prior estimates	48	22	34	104
Reserves, December 31, 2004	**648**	**303**	**115**	**1,066**
Extensions & discoveries	**98**	**-**	**-**	**98**
Infill drilling	**3**	**3**	**2**	**8**
Improved recovery	**-**	**-**	**-**	**-**
Property purchases	**-**	**-**	**15**	**15**
Property disposals	**(3)**	**-**	**-**	**(3)**
Production	**(70)**	**(25)**	**(8)**	**(103)**
Revisions of prior estimates	**18**	**9**	**10**	**37**
Reserves, December 31, 2005	**694**	**290**	**134**	**1,118**
Proved and probable reserves (mmbbl)				
Reserves, December 31, 2003	**857**	**317**	**133**	**1,307**
Extensions & discoveries	20	-	-	20
Infill drilling	29	49	-	78
Improved recovery	2	10	-	12
Property purchases	49	49	-	98
Property disposals	-	-	-	-
Production	(66)	(24)	(4)	(94)
Revisions of prior estimates	35	14	67	116
Reserves, December 31, 2004	**926**	**415**	**196**	**1,537**
Extensions & discoveries	**200**	**-**	**-**	**200**
Infill drilling	**3**	**5**	**6**	**14**
Improved recovery	**0**	**-**	**-**	**0**
Property purchases	**-**	**-**	**17**	**17**
Property disposals	**(4)**	**-**	**-**	**(4)**
Production	**(70)**	**(25)**	**(8)**	**(103)**
Revisions of prior estimates	**(20)**	**22**	**(5)**	**(3)**
Reserves, December 31, 2005	**1,035**	**417**	**206**	**1,658**

CONVENTIONAL NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES[1]

	North America	North Sea	Offshore West Africa	Total
Proved reserves (bcf)				
Reserves, December 31, 2003	**2,426**	**62**	**64**	**2,552**
Extensions & discoveries	334	-	-	334
Infill drilling	74	-	-	74
Improved recovery	6	-	-	6
Property purchases	182	10	-	192
Property disposals	(8)	-	-	(8)
Production	(383)	(18)	(3)	(404)
Revisions of prior estimates	(40)	(27)	11	(56)
Reserves, December 31, 2004	**2,591**	**27**	**72**	**2,690**
Extensions & discoveries	**506**	**-**	**-**	**506**
Infill drilling	**22**	**-**	**-**	**22**
Improved recovery	**8**	**-**	**-**	**8**
Property purchases	**6**	**-**	**-**	**6**
Property disposals	**(23)**	**-**	**-**	**(23)**
Production	**(411)**	**(7)**	**(1)**	**(419)**
Revisions of prior estimates	**42**	**9**	**1**	**52**
Reserves, December 31, 2005	**2,741**	**29**	**72**	**2,842**
Proved and probable reserves (bcf)				
Reserves, December 31, 2003	**2,919**	**102**	**72**	**3,093**
Extensions & discoveries	418	-	-	418
Infill drilling	106	-	-	106
Improved recovery	6	-	-	6
Property purchases	236	18	-	254
Property disposals	(10)	-	-	(10)
Production	(383)	(18)	(3)	(404)
Revisions of prior estimates	27	(45)	21	3
Reserves, December 31, 2004	**3,319**	**57**	**90**	**3,466**
Extensions & discoveries	**645**	**-**	**-**	**645**
Infill drilling	**23**	**-**	**1**	**24**
Improved recovery	**14**	**-**	**-**	**14**
Property purchases	**8**	**-**	**-**	**8**
Property disposals	**(30)**	**-**	**-**	**(30)**
Production	**(411)**	**(7)**	**(1)**	**(419)**
Revisions of prior estimates	**(20)**	**19**	**20**	**19**
Reserves, December 31, 2005	**3,548**	**69**	**110**	**3,727**

The following information for reserves before royalties is provided for comparative purposes:

CONVENTIONAL RESERVES, BEFORE ROYALTIES[1]

	December 31, 2005			
	Proved Developed[2]	**Proved Undeveloped**[2]	**Proved Total** [2]	**Proved and Probable**[3]
Crude oil & NGLs (mmbbl)				
North America	**462**	**323**	**785**	**1,154**
North Sea	**214**	**76**	**290**	**417**
Offshore West Africa	**86**	**62**	**148**	**230**
	762	**461**	**1,223**	**1,801**
Natural gas (bcf)				
North America	**2,844**	**534**	**3,378**	**4,372**
North Sea	**16**	**13**	**29**	**69**
Offshore West Africa	**11**	**72**	**83**	**127**
	2,871	**619**	**3,490**	**4,568**
Total reserves (mmboe)	**1,240**	**564**	**1,804**	**2,562**

	December 31, 2004			
	Proved Developed[2]	**Proved Undeveloped**[2]	**Proved Total** [2]	**Proved and Probable**[3]
Crude oil & NGLs (mmbbl)				
North America	399	296	695	992
North Sea	218	85	303	415
Offshore West Africa	21	104	125	214
	638	485	1,123	1,621
Natural gas (bcf)				
North America	2,743	459	3,202	4,100
North Sea	12	15	27	57
Offshore West Africa	6	75	81	102
	2,761	549	3,310	4,259
Total reserves (mmboe)	1,098	576	1,674	2,330

CONVENTIONAL FINDING AND ONSTREAM COSTS

	2005	2004	2003	Three Year Total
Net reserve replacement expenditures ($ millions)	**3,361**	4,259	2,283	**9,903**
Net reserve additions[8] (mmboe)				
Proved	**251**	354	185	**790**
Proved and probable	**337**	453	441	**1,231**
Finding and on stream costs per net boe[9]				
Proved	**13.41**	12.03	12.34	**12.55**
Proved and probable	**9.97**	9.40	5.18	**8.05**

(1) Reserve estimates and present value calculations are based upon year end constant reference price assumptions as detailed below.

Crude oil & NGLs	*Company Average Price (C$/bbl)*	*WTI @ Cushing Oklahoma (US$/bbl)*	*Hardisty Heavy 12º API (C$/bbl)*	*North Sea Brent (US$/bbl)*
2005	*46.12*	*61.04*	*32.64*	*58.21*
2004	*32.14*	*44.04*	*17.45*	*40.47*
2003	*32.02*	*32.56*	*26.16*	*30.14*

Natural gas	*Company Average Price (C$/bbl)*	*Henry Hub Louisiana (US$/mmbtu)*	*Alberta AECO C (C$/mmbtu)*	*British Columbia Huntingdon Sumas (C$/mmbtu)*
2005	*9.45*	*10.08*	*9.99*	*9.53*
2004	*6.44*	*6.62*	*6.78*	*6.94*
2003	*6.63*	*5.80*	*6.88*	*6.94*

A foreign exchange rate of US$0.86/C$1.00 was used in the 2005 evaluation. A foreign exchange rate of US$0.83/C$1.00 was used in the 2004 evaluation. A foreign exchange rate of US$0.77/$C1.00 was used in the 2003 evaluation.

(2) Proved reserve estimates and values were evaluated in accordance with the Securities and Exchange Commission (SEC) requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) Proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

(4) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(5) Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(6) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Only future development costs and associated material well abandonment costs have been applied against future net revenues except for Offshore West Africa where all abandonment costs have been applied.

(7) Synthetic crude oil reserves are based on upgrading of the bitumen reserves. The reserve values shown for bitumen and synthetic crude oil are not additive.

(8) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(9) Reserves finding and on stream costs are determined by dividing total capital costs for each year excluding cost associated with head office, abandonments, midstream and the Horizon Project by net reserves additions for that year.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The 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 months and the year ended December 31, 2005 in relation to the comparable periods in 2004 and the third quarter of 2005. The accompanying tables form an integral part of this MD&A. This MD&A is dated February 21, 2006.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Revenue, before royalties	**$ 3,032**	$ 2,918	$ 1,969	**$ 10,107**	$ 7,547
Net earnings	**$ 1,104**	$ 151	$ 577	**$ 1,050**	$ 1,405
Per common share – basic[1]	**$ 2.06**	$ 0.28	$ 1.07	**$ 1.96**	$ 2.62
– diluted[1]	**$ 2.06**	$ 0.28	$ 1.06	**$ 1.95**	$ 2.60
Adjusted net earnings from operations[2]	**$ 601**	$ 593	$ 321	**$ 2,034**	$ 1,405
Per common share – basic[1]	**$ 1.12**	$ 1.10	$ 0.60	**$ 3.79**	$ 2.62
– diluted[1]	**$ 1.12**	$ 1.10	$ 0.59	**$ 3.78**	$ 2.60
Cash flow from operations[3]	**$ 1,490**	$ 1,386	$ 950	**$ 5,021**	$ 3,769
Per common share – basic[1]	**$ 2.78**	$ 2.58	$ 1.77	**$ 9.36**	$ 7.03
– diluted[1]	**$ 2.78**	$ 2.57	$ 1.76	**$ 9.33**	$ 6.98
Capital expenditures, net of dispositions	**$ 1,679**	$ 1,272	$ 1,421	**$ 4,932**	$ 4,633

(1) 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 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			*Year Ended*	
($ millions)	***Dec 31 2005*** [(a)]	*Sep 30 2005*	*Dec 31 2004*	***Dec 31 2005***	*Dec 31 2004*
Net earnings as reported	***$ 1,104***	*$ 151*	*$ 577*	***$ 1,050***	*$ 1,405*
Stock-based compensation, net of tax[(b)]	***75***	*135*	*17*	***481***	*168*
Unrealized risk management (gain) loss, net of tax[(c)]	***(583)***	*430*	*(212)*	***607***	*(27)*
Unrealized foreign exchange loss (gain), net of tax[(d)]	***5***	*(104)*	*(61)*	***(85)***	*(75)*
Effect of statutory tax rate changes on future income tax liabilities[(e)]	***-***	*(19)*	*-*	***(19)***	*(66)*
Adjusted net earnings from operations	***$ 601***	*$ 593*	*$ 321*	***$ 2,034***	*$ 1,405*

(a) The Company's adjusted net earnings in the fourth quarter reflects year-to-date adjustments in effective tax rates.

(b) 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 with changes in the fair value, net of taxes, flowing through net earnings.

(c) 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 materially different than reflected in these financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

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

(e) All substantively enacted adjustments to 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 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.

($ millions)	Three Months Ended **Dec 31 2005**	Sep 30 2005	Dec 31 2004	Year Ended **Dec 31 2005**	Dec 31 2004
Net earnings	**$ 1,104**	$ 151	$ 577	**$ 1,050**	$ 1,405
Non-cash items:					
Depletion, depreciation and amortization	**550**	505	501	**2,013**	1,769
Asset retirement obligation accretion	**16**	18	16	**69**	51
Stock-based compensation	**125**	199	24	**723**	249
Unrealized risk management activities	**(825)**	633	(317)	**925**	(40)
Unrealized foreign exchange loss (gain)	**5**	(124)	(77)	**(103)**	(94)
Deferred petroleum revenue tax (recovery)	**1**	(14)	(32)	**(9)**	(45)
Future income tax expense	**514**	18	258	**353**	474
Cash flow from operations	**$ 1,490**	$ 1,386	$ 950	**$ 5,021**	$ 3,769

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

For the year ended December 31, 2005, the Company recorded net earnings of $1,050 million compared to net earnings of $1,405 million for the year ended December 31, 2004. Net earnings for 2005 includes unrealized after-tax expenses of $984 million related to the Company's risk management activities and stock-based compensation plans, net of foreign exchange gains and the effect of statutory tax rate changes ($nil for 2004). Excluding the effects of these items, adjusted net earnings from operations increased 45% to $2,034 million from $1,405 million for 2004 due to continuing strong crude oil and natural gas prices and record levels of total production on a barrel of oil ("boe") basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar.

For the fourth quarter of 2005, the Company reported net earnings of $1,104 million compared to net earnings of $577 million for the fourth quarter of 2004 and $151 million in the third quarter of 2005. Net earnings in the fourth quarter of 2005 included unrealized after-tax income of $503 million related to risk management activities, net of stock-based compensation expenses and foreign exchange losses, compared to $256 million of net after-tax income in the fourth quarter of 2004 and $442 million of net after-tax expenses in the third quarter of 2005. Excluding these items, adjusted net earnings from operations in the fourth quarter of 2005 increased by 87% to $601 million from $321 million in the comparable period in 2004, and increased slightly from 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 expense and fluctuations in foreign exchange rates.

In January 2005, the Board of Directors authorized the expansion of the Company's commodity 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 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 budgeted 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 60% of budgeted 2006 natural gas volumes have similarly been hedged through the use of collars.

As effective as the Company's hedges are against reference commodity prices, a substantial portion of the derivative 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 December 31, 2005, the implied price differentials for the non-designated hedges for future years. The cash settlement amount of the risk management financial derivative instruments may vary materially 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 mark-to-market value at December 31, 2005.

Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $925 million ($607 million after-tax) unrealized loss on its risk management activities for the year ended December 31, 2005, net of an $825 million ($583 million after-tax) unrealized gain for the three months ended December 31, 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 $723 million ($481 million after-tax) stock-based compensation expense for the year ended December 31, 2005 in connection with the 125% appreciation in the Company's share price during the year, and a $125 million ($75 million after-tax) stock-based compensation expense as a result of the 10% appreciation in the Company's share price in the fourth quarter of 2005 (December 31, 2005 – C$57.63; September 30, 2005 - C$52.50; 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 earnings, or capitalized during the construction period in the case of the Horizon Oil Sands Project . 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 December 31, 2005. In periods when substantial stock price changes occur, the Company's earnings are subject to significant 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 year ended December 31, 2005 increased 33% to a record level of $5,021 million from $3,769 million for the year ended December 31, 2004. Cash flow from operations in the fourth quarter of 2005 increased to $1,490 million, up 57% from $950 million for the fourth quarter of 2004 and up 8% from $1,386 million in the prior quarter. The increase in cash flow from operations from 2004 was due mainly to strong commodity prices and record levels of total production on a boe basis, offset by realized risk management activities and the impact of a strengthening Canadian dollar.

Total production averaged 552,960 boe/d for the year ended December 31, 2005, up 8% from 513,835 boe/d for the year ended December 31, 2004. Production for the fourth quarter of 2005 increased 9% to 577,505 boe/d from 530,745 boe/d in the fourth quarter of 2004 and increased 1% from 2005 third quarter production of 571,911 boe/d.

OPERATING HIGHLIGHTS

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs ($/bbl)(1)					
Sales price(2)	**$ 46.38**	$ 57.35	$ 36.92	**$ 46.86**	$ 37.99
Royalties	**3.89**	5.11	2.95	**3.97**	3.16
Production expense	**10.33**	11.48	10.41	**11.17**	10.05
Netback	**$ 32.16**	$ 40.76	$ 23.56	**$ 31.72**	$ 24.78
Natural gas ($/mcf)(1)					
Sales price(2)	**$ 11.67**	$ 8.61	$ 6.77	**$ 8.57**	$ 6.50
Royalties	**2.30**	1.93	1.34	**1.75**	1.35
Production expense	**0.76**	0.76	0.68	**0.73**	0.67
Netback	**$ 8.61**	$ 5.92	$ 4.75	**$ 6.09**	$ 4.48
Barrels of oil equivalent ($/boe)(1)					
Sales price(2)	**$ 56.08**	$ 54.87	$ 38.51	**$ 48.77**	$ 38.45
Royalties	**8.01**	7.84	5.21	**6.82**	5.37
Production expense	**7.93**	8.56	7.61	**8.21**	7.35
Netback	**$ 40.14**	$ 38.47	$ 25.69	**$ 33.74**	$ 25.73

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Including transportation costs and excluding risk management activities.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
WTI benchmark price (US$/bbl)[1]	**$ 60.04**	$ 63.17	$ 48.27	**$ 56.61**	$ 41.43
Dated Brent benchmark price (US$/bbl)	**$ 56.93**	$ 61.47	$ 44.06	**$ 54.45**	$ 38.28
Differential to LLB blend (US$/bbl)	**$ 24.09**	$ 18.73	$ 19.61	**$ 20.83**	$ 13.44
Condensate benchmark price (US$/bbl)	**$ 60.41**	$ 63.40	$ 48.56	**$ 57.25**	$ 41.62
NYMEX benchmark price (US$/mmbtu)	**$ 12.83**	$ 8.23	$ 6.86	**$ 8.56**	$ 6.09
AECO benchmark price (C$/GJ)	**$ 11.07**	$ 7.73	$ 6.71	**$ 8.05**	$ 6.43
US / Canadian dollar average exchange rate (US$)	**0.8523**	0.8325	0.8195	**0.8253**	0.7683

(1) Refers to West Texas Intermediate crude oil barrel prices at Cushing, Oklahoma.

World crude oil prices reached all-time highs in 2005, supported by:

– Strong demand growth, particularly in the United States, China and India.

– Ongoing geopolitical uncertainties.

– Production losses in the Gulf of Mexico from hurricanes Katrina and Rita. Many platforms and refineries are not expected to be operational until sometime in the third quarter of 2006.

– Restricted crude oil refining capacity.

West Texas Intermediate (“WTI”) averaged US$56.61 per bbl for the year ended December 31, 2005, an increase of 37% compared to US$41.43 per bbl for the year ended December 31, 2004. In the fourth quarter of 2005, WTI averaged US$60.04 per bbl, up 24% from US$48.27 per bbl in the comparable period in 2004, but down 5% from US$63.17 per bbl in the third quarter of 2005.

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 mitigated by wider heavy crude oil differentials, which increased 55% to US$20.83 per bbl for the year ended December 31, 2005 from US$13.44 per bbl for the year ended December 31, 2004. For the three months ended December 31, 2005, heavy crude oil differentials increased 23% compared to the fourth quarter of 2004 to average US$24.09 per bbl, primarily due to higher WTI pricing and the premium paid for lighter barrels. These differentials increased 29% from the third quarter of 2005 due to decreased demand for heavy blends relative to light blends. This reflects normal seasonal widening, as the asphalt season slows for the winter.

Heavy crude oil differentials in 2005 continued to be higher than the long-term average primarily due to physical limitations for demand at refineries. Following hurricanes Katrina and Rita, refiners sought to process lighter barrels to increase their yields of gasoline and distillates, which resulted in the further deterioration of heavy crude oil differentials. Plant turnarounds and maintenance during the year, additional problems at refineries and upgraders, the higher cost of diluents, 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 American natural gas prices also climbed in 2005 due to concerns around supply as well as the impact of higher crude oil prices. NYMEX natural gas prices increased 41% to average US$8.56 per mmbtu for the year ended December 31, 2005, up from US$6.09 per mmbtu for the year ended December 31, 2004. In the fourth quarter of 2005, NYMEX natural gas prices increased 87% to average US$12.83 per mmbtu, up from US$6.86 per mmbtu in the comparable period in 2004, and increased 56% from US$8.23 per mmbtu in the prior quarter. AECO natural gas pricing moved directionally with NYMEX, increasing 25% to average $8.05 per GJ for the year ended December 31, 2005, up from $6.43 per GJ for the year ended December 31, 2004. AECO natural gas prices increased 65% to average $11.07 per GJ in the fourth quarter of 2005, up from $6.71 per GJ in the comparable period in 2004, and increased 43% from $7.73 per GJ in the prior quarter.

PRODUCT PRICES[1]

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs ($/bbl)[2]					
North America	**$ 37.96**	$ 51.77	$ 30.99	**$ 39.62**	$ 33.16
North Sea	**$ 66.88**	$ 74.46	$ 52.77	**$ 66.57**	$ 51.37
Offshore West Africa	**$ 60.19**	$ 59.09	$ 51.28	**$ 59.91**	$ 49.05
Company average	**$ 46.38**	$ 57.35	$ 36.92	**$ 46.86**	$ 37.99
Natural gas ($/mcf)[2]					
North America	**$ 11.79**	$ 8.69	$ 6.88	**$ 8.65**	$ 6.61
North Sea	**$ 3.40**	$ 2.64	$ 3.26	**$ 3.17**	$ 3.73
Offshore West Africa	**$ 5.13**	$ 5.52	$ 4.73	**$ 5.91**	$ 5.25
Company average	**$ 11.67**	$ 8.61	$ 6.77	**$ 8.57**	$ 6.50
Company average ($/boe)[2]	**$ 56.08**	$ 54.87	$ 38.51	**$ 48.77**	$ 38.45
Percentage of revenue (excluding midstream revenue)					
Crude oil and NGLs	**48%**	60%	53%	**54%**	54%
Natural gas	**52%**	40%	47%	**46%**	46%

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

(2) Amounts expressed on a per unit basis are based on sales volumes.

Company realized crude oil prices increased 23% to average $46.86 per bbl for the year ended December 31, 2005, up from $37.99 per bbl for the year ended December 31, 2004. For the fourth quarter 2005, realized crude oil prices increased 26% to average $46.38 per bbl, up from $36.92 per bbl in the comparable period in 2004. This increase was primarily due to higher benchmark world crude oil prices, as well as an increased proportion of crude oil and NGLs sales coming from Offshore West Africa, offset by higher heavy crude oil differentials and a stronger Canadian dollar. Company realized crude oil prices for the fourth quarter of 2005 decreased 19% from the prior quarter due to the seasonal widening of heavy differentials, lower WTI and a strengthening Canadian dollar.

The Company's realized natural gas price increased 32% to average $8.57 per mcf for the year ended December 31, 2005, up from $6.50 per mcf for the year ended December 31, 2004, primarily due to a continued strengthening in benchmark natural gas pricing during the year. In the fourth quarter of 2005, the realized natural gas price averaged $11.67 per mcf, up 72% from $6.77 per mcf in the comparable period in 2004 and up 36% from $8.61 per mcf in the prior quarter.

North America

North America realized crude oil prices increased 19% to average $39.62 per bbl for the year ended December 31, 2005, up from $33.16 per bbl for the year ended December 31, 2004. Realized crude oil prices in the fourth quarter of 2005 averaged $37.96 per bbl, up 22% from $30.99 per bbl in the comparable period in 2004 and down 27% from $51.77 per bbl in the prior quarter. The increase in the realized crude oil price in 2005 was mainly due to higher benchmark crude oil prices, partially offset by wider heavy crude oil differentials and the strengthening Canadian dollar. The decrease compared to the third quarter of 2005 was primarily due to lower benchmark crude oil prices and a widening heavy crude oil differential.

In North America the Company continues to focus on its crude oil marketing strategy, including the development of a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new geographic 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 140,000 bbl/d. During the fourth quarter, the Company contributed approximately 139,000 bbl/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 late in the first quarter of 2006. 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 31% to average $8.65 per mcf for the year ended December 31, 2005, up from $6.61 per mcf for the year ended December 31, 2004. In the fourth quarter of 2005, the realized natural gas price averaged $11.79 per mcf, up 71% from $6.88 per mcf in the comparable period in 2004 and up 36% from $8.69 per mcf in the prior quarter. The increases were due to supply concerns and 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:

	Q4 2005	Q3 2005	Q4 2004
Wellhead Price(1)(2)			
Light crude oil and NGLs (C$/bbl)	**$ 61.33**	$ 66.62	$ 49.34
Pelican Lake crude oil (C$/bbl)	**$ 34.86**	$ 50.30	$ 29.90
Primary heavy crude oil (C$/bbl)	**$ 31.00**	$ 48.86	$ 24.96
Thermal heavy crude oil (C$/bbl)	**$ 28.84**	$ 44.84	$ 25.52
Natural gas (C$/mcf)	**$ 11.79**	$ 8.69	$ 6.88

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

(2) Amounts expressed on a per unit basis are based on sales volumes.

North Sea

North Sea realized crude oil prices increased 30% to average $66.57 per bbl for the year ended December 31, 2005, up from $51.37 per bbl for the year ended December 31, 2004. Realized pricing increased 27% to average $66.88 per bbl in the fourth quarter of 2005, up from $52.77 per bbl in the comparable period in 2004 and down 10% from $74.46 per bbl in the prior quarter. The increase in the realized crude oil price compared to 2004 was due mainly to higher world benchmark crude oil prices and a narrowing of the average Brent differential, offset by the strengthening Canadian dollar. The decrease in the realized crude oil prices in the fourth quarter of 2005 compared to the third quarter was primarily due to lower benchmark world crude oil prices and widening Brent differentials.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 22% to average $59.91 per bbl for the year ended December 31, 2005, an increase from $49.05 per bbl for the year ended December 31, 2004, and averaged $60.19 per bbl in the fourth quarter of 2005, a 17% increase from $51.28 per bbl in the comparable period in 2004. 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.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. For production where revenue has not yet been recognized, the related crude oil inventory volumes, by segment, were as follows:

(bbls)	Dec 31, 2005
North America, related to Corsicana pipeline fill	**484,157**
North Sea, related to timing of liftings	**747,141**
Offshore West Africa, related to timing of liftings	**412,841**
	1,644,139

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs (bbl/d)					
North America	**230,263**	231,260	214,493	**221,669**	206,225
North Sea	**66,798**	73,543	69,971	**68,593**	64,706
Offshore West Africa	**43,207**	29,921	11,240	**22,906**	11,558
	340,268	334,724	295,704	**313,168**	282,489
Natural gas (mmcf/d)					
North America	**1,402**	1,400	1,365	**1,416**	1,330
North Sea	**15**	18	40	**19**	50
Offshore West Africa	**6**	5	5	**4**	8
	1,423	1,423	1,410	**1,439**	1,388
Total barrel of oil equivalent (boe/d)	**577,505**	571,911	530,745	**552,960**	513,835
Product mix					
Light crude oil and NGLs	**28%**	27%	24%	**26%**	24%
Pelican Lake crude oil	**5%**	4%	4%	**4%**	4%
Primary heavy crude oil	**17%**	16%	18%	**17%**	19%
Thermal heavy crude oil	**9%**	11%	10%	**10%**	8%
Natural gas	**41%**	42%	44%	**43%**	45%

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs (bbl/d)					
North America	**198,047**	200,055	187,106	**191,751**	180,011
North Sea	**66,664**	73,424	69,863	**68,487**	64,598
Offshore West Africa	**42,081**	29,162	10,908	**22,293**	11,221
	306,792	302,641	267,877	**282,531**	255,830
Natural gas (mmcf/d)					
North America	**1,124**	1,085	1,092	**1,125**	1,048
North Sea	**15**	18	40	**18**	50
Offshore West Africa	**6**	5	5	**4**	7
	1,145	1,108	1,137	**1,147**	1,105
Total barrel of oil equivalent (boe/d)	**497,679**	487,292	457,356	**473,742**	440,022

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

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

Record total crude oil and natural gas production averaged 552,960 boe/d for the year ended December 31, 2005, an increase of 8% or 39,125 boe/d from the year ended December 31, 2004. Fourth quarter total production in 2005 also reached record levels of 577,505 boe/d, an increase of 9% or 46,760 boe/d compared to the fourth quarter of 2004. The increase in production year over year was due to organic growth from 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 of 2005, as well as the full year impact of accretive acquisitions completed in 2004.

Total crude oil and NGLs production for the year ended December 31, 2005 increased 11% to 313,168 bbl/d from 282,489 bbl/d for the year ended December 31, 2004. In the fourth quarter of 2005, production was 340,268 bbl/d, an increase of 15% from 295,704 bbl/d in the fourth quarter of 2004. Crude oil and NGLs production in the fourth quarter of 2005 was in line with the Company’s previously issued guidance of 323,000 to 352,000 bbl/d.

Natural gas production continues to represent the Company’s largest product offering. Natural gas production for the year ended December 31, 2005 increased 4% or 51 mmcf/d to average 1,439 mmcf/d compared to 1,388 mmcf/d for the year ended December 31, 2004. Growth in natural gas production was negatively affected by the early arrival of spring breakup and weather related delays due to unusually wet conditions as well as an overall increase in industry activity. The market for the necessary oilfield services and material has become increasingly competitive, resulting in drilling, completion, tie-in and maintenance delays. The Company’s fourth quarter natural gas production of 1,423 mmcf/d was within the Company’s previously issued guidance of 1,411 to 1,460 mmcf/d.

The Company expects annual production levels in 2006 to average 1,468 to 1,551 mmcf/d of natural gas and 335 to 373 mbbl/d of crude oil and NGLs. First quarter 2006 production guidance is 1,426 to 1,475 mmcf/d of natural gas and 306 to 334 mbbl/d of crude oil and NGLs.

North America

North America crude oil and NGLs production for the year ended December 31, 2005 increased 7% or 15,444 bbl/d to average 221,669 bbl/d, up from 206,225 bbl/d for the year ended December 31, 2004. Production in the fourth quarter of 2005 increased 7% or 15,770 bbl/d to average 230,263 bbl/d, up from 214,493 bbl/d in the comparable period in 2004. 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. Fourth quarter crude oil and NGLs production remained relatively unchanged from third quarter production.

North America natural gas production for the year ended December 31, 2005 increased 6% or 86 mmcf/d to average 1,416 mmcf/d, up from 1,330 mmcf/d in the comparable period in 2004. Natural gas production increased as a result of organic growth and the full year impact of 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 during the summer months. In the fourth quarter of 2005, production increased 3% or 37 mmcf/d to average 1,402 mmcf/d, up from 1,365 mmcf/d in the comparable period in 2004. Production growth was impacted by the increased demand for oilfield services and materials, which caused delays in the timing of production being brought on stream.

North Sea

North Sea crude oil production for the year ended December 31, 2005 was 68,593 bbl/d, an increase of 6% from 64,706 bbl/d for 2004. Crude oil production in the fourth quarter of 2005 reached 66,798 bbl/d, lower than both production of 69,971 bbl/d in the fourth quarter of 2004 and 73,543 bbl/d in the third quarter of 2005. Production levels were in line with expectations, reflecting anticipated curtailments at the Lyell Field and the Columba B and E Terraces, continued restrictions at Murchison Field due to third party natural gas export facilities and production declines at the satellite Playfair Field.

Natural gas production in the North Sea for the year ended December 31, 2005 decreased 62% to average 19 mmcf/d, down from 50 mmcf/d for the year ended December 31, 2004. Natural gas production in the fourth quarter of 2005 of 15 mmcf/d decreased 63% from fourth quarter 2004. The decrease in natural gas production 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 resulted in reductions in natural gas production in 2005.

Offshore West Africa

Offshore West Africa crude oil production for the year ended December 31, 2005 increased 98% to 22,906 bbl/d from 11,558 bbl/d for the year ended December 31, 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 increased production from additional infill wells drilled in East Espoir. Fourth quarter 2005 production increased to 43,207 bbl/d from 11,240 bbl/d in the fourth quarter of 2004, and increased by 44% from third quarter 2005 production of 29,921 bbl/d as a result of production from the Baobab Field.

ROYALTIES

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs ($/bbl)(1)					
North America	**$ 5.39**	$ 6.99	$ 3.96	**$ 5.37**	$ 4.21
North Sea	**$ 0.14**	$ 0.12	$ 0.08	**$ 0.10**	$ 0.08
Offshore West Africa	**$ 1.57**	$ 1.54	$ 1.52	**$ 1.62**	$ 1.43
Company average	**$ 3.89**	$ 5.11	$ 2.95	**$ 3.97**	$ 3.16
Natural gas ($/mcf)(1)					
North America	**$ 2.34**	$ 1.96	$ 1.39	**$ 1.78**	$ 1.40
North Sea	**$ -**	$ -	$ -	**$ -**	$ -
Offshore West Africa	**$ 0.14**	$ 0.13	$ 0.14	**$ 0.16**	$ 0.15
Company average	**$ 2.30**	$ 1.93	$ 1.34	**$ 1.75**	$ 1.35
Company average ($/boe)(1)	**$ 8.01**	$ 7.84	$ 5.21	**$ 6.82**	$ 5.37
Percentage of revenue(2)					
Crude oil and NGLs	**8%**	9%	8%	**8%**	8%
Natural gas	**20%**	22%	20%	**20%**	21%
Boe	**14%**	14%	14%	**14%**	14%

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

North America

North America crude oil and NGLs royalties per bbl for the year and the three months ended December 31, 2005 increased from the comparable periods in 2004 primarily due to higher benchmark crude oil prices. Fourth quarter 2005 crude oil and NGLs royalties per bbl decreased from the third quarter of 2005 due to lower benchmark crude oil prices, wider heavy crude oil differentials and a strengthening Canadian dollar.

Natural gas royalties increased from the comparable periods in 2004 and the prior quarter due to higher benchmark natural gas prices, offset by a stronger Canadian dollar. Fourth quarter royalties reflect adjustments relating to prior quarters.

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 Production Sharing Contracts ("PSCs"). Under the PSCs, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover its capital and operating costs and the 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 profit revenue attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the PSCs.

PRODUCTION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Crude oil and NGLs ($/bbl)(1)					
North America	**$ 10.92**	$ 10.77	$ 9.06	**$ 10.49**	$ 8.94
North Sea	**$ 12.11**	$ 15.15	$ 14.96	**$ 14.94**	$ 14.03
Offshore West Africa	**$ 5.62**	$ 5.81	$ 7.82	**$ 6.50**	$ 7.59
Company average	**$ 10.33**	$ 11.48	$ 10.41	**$ 11.17**	$ 10.05
Natural gas ($/mcf)(1)					
North America	**$ 0.74**	$ 0.74	$ 0.63	**$ 0.71**	$ 0.62
North Sea	**$ 1.96**	$ 2.30	$ 2.29	**$ 2.44**	$ 2.07
Offshore West Africa	**$ 0.80**	$ 1.09	$ 1.31	**$ 1.05**	$ 1.33
Company average	**$ 0.76**	$ 0.76	$ 0.68	**$ 0.73**	$ 0.67
Company average ($/boe)(1)	**$ 7.93**	$ 8.56	$ 7.61	**$ 8.21**	$ 7.35

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense per bbl for the year and the quarter ended December 31, 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 given a larger portion of the Company's crude oil production was comprised of higher cost thermal crude oil in 2005 versus 2004.

North America natural gas production expense per mcf for the year and the three months ended December 31, 2005 increased from the comparable periods in 2004. The increase from 2004 was due to the service and fuel cost pressures noted above, offset by the positive impact of higher production.

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. Fourth quarter production expense decreased from the prior quarter due to the timing of liftings from various fields and given production was diverted from the Kyle Field to the Banff FPSO.

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 for the year and quarter ended December 31, 2005 compared to 2004 and the third quarter of 2005 were primarily impacted by the commencement of production from the Baobab Field in August 2005.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2005**	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Revenue	**$ 21**	$ 18	$ 18	**$ 77**	$ 68
Production expense	**8**	5	5	**24**	20
Midstream cash flow	**13**	13	13	**53**	48
Depreciation	**2**	2	2	**8**	7
Segment earnings before taxes	**$ 11**	$ 11	$ 11	**$ 45**	$ 41

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 control the transport of its own production volumes 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 heavier crude oil.

DEPLETION, DEPRECIATION AND AMORTIZATION(1)

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Expense ($ millions)	**$ 548**	$ 503	$ 499	**$ 2,005**	$ 1,762
$/boe(2)	**$ 10.44**	$ 9.75	$ 10.24	**$ 10.02**	$ 9.37

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

(2) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, Depreciation and Amortization ("DD&A") for the year and the three months ended December 31, 2005 increased in total and on a boe basis from the comparable periods in 2004 and the third quarter. 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 acquisitions completed late in 2004, 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 in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Expense ($ millions)	**$ 16**	$ 18	$ 16	**$ 69**	$ 51
$/boe[1]	**$ 0.30**	$ 0.34	$ 0.33	**$ 0.34**	$ 0.27

(1) Amounts expressed on a per unit basis are based on sales volumes.

The increase in asset retirement obligation accretion expense year over year was primarily due to increased activity in the North America conventional drilling program and revised provincial reclamation legislation.

ADMINISTRATION EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Net expense ($ millions)	**$ 36**	$ 38	$ 36	**$ 151**	$ 125
$/boe[1]	**$ 0.68**	$ 0.75	$ 0.72	**$ 0.75**	$ 0.66

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the year ended December 31, 2005 increased in total and on a boe basis from the year ended December 31, 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 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 year ended December 31, 2005, the Company recognized $17 million of compensation expense under the Share Bonus Plan (December 31, 2004 - $10 million).

STOCK-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2005**	Sep 30 2005	Dec 31 2004[1]	**Dec 31 2005**	Dec 31 2004[1]
Stock option plan	**$ 125**	$ 199	$ 24	**$ 723**	$ 249

(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 $723 million ($481 million after tax) stock-based compensation expense for the year ended December 31, 2005 in connection with the 125% appreciation in the Company's share price, and a $125 million ($75 million after tax) stock-based compensation expense as a result of the 10% appreciation in the Company's share price in the fourth quarter of 2005 (December 31, 2005 – C$57.63; September 30, 2005 - C$52.50; 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 net earnings, or capitalized during the construction period in the case of the Horizon Oil Sands Project. 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 December 31, 2005. In periods when substantial stock price changes occur, the Company is subject to significant earnings volatility.

For the year ended December 31, 2005, the Company paid $227 million for stock options surrendered for cash settlement (December 31, 2004 - $80 million).

INTEREST EXPENSE

	Three Months Ended			Year Ended	
	Dec 31 2005	Sep 30 2005	Dec 31 2004[1]	**Dec 31 2005**	Dec 31 2004[1]
Interest expense, net ($ millions)	**$ 28**	$ 38	$ 48	**$ 149**	$ 189
$/boe[2]	**$ 0.53**	$ 0.73	$ 1.00	**$ 0.74**	$ 1.01
Average effective interest rate	**5.7%**	6.0%	5.1%	**5.6%**	5.2%

(1) Restated to conform to current year presentation.

(2) Amounts expressed on a per unit basis are based on sales volumes.

Net interest expense decreased on a total and boe basis for the year and the three months ended December 31, 2005 from the comparable periods in 2004 primarily due to the capitalization of construction period interest related to the Horizon Project in 2005 (year ended December 31, 2005 – $72 million; three months ended December 31, 2005 - $27 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 instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not used for trading or speculative purposes. Changes in fair value of derivative financial instruments designated as hedges are not recognized in net earnings until such time as the corresponding gains or losses on the related hedged items are also recognized. Changes in fair value of derivative financial instruments not designated as hedges are recognized in the consolidated balance sheets each period with the offset reflected in risk management activities in the statement of earnings.

The Company formally documents all hedging transactions at the inception of the hedging relationship in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated both at inception of the hedge and on an ongoing basis.

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. 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 **Dec 31 2005**	Three Months Ended Sep 30 2005	Three Months Ended Dec 31 2004	Year Ended **Dec 31 2005**	Year Ended Dec 31 2004
Realized loss (gain)					
Crude oil and NGLs financial instruments	**$ 235**	$ 319	$ 180	**$ 753**	$ 501
Natural gas financial instruments	**242**	49	2	**283**	5
Interest rate swaps	**(1)**	-	(7)	**(9)**	(32)
	$ 476	$ 368	$ 175	**$ 1,027**	$ 474
Unrealized (gain) loss					
Crude oil and NGLs financial instruments	**$ (514)**	$ 286	$ (321)	**$ 847**	$ (47)
Natural gas financial instruments	**(307)**	348	-	**77**	-
Interest rate swaps	**(4)**	(1)	4	**1**	7
	$ (825)	$ 633	$ (317)	**$ 925**	$ (40)
Total	**$ (349)**	$ 1,001	$ (142)	**$ 1,952**	$ 434

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 **Dec 31 2005**	Three Months Ended Sep 30 2005	Three Months Ended Dec 31 2004	Year Ended **Dec 31 2005**	Year Ended Dec 31 2004
Crude oil and NGLs ($/bbl)(1)	**$ 7.67**	$ 10.69	$ 6.63	**$ 6.68**	$ 4.85
Natural gas ($/mcf)(1)	**$ 1.85**	$ 0.38	$ -	**$ 0.54**	$ 0.01

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

($ millions)	Three Months Ended **Dec 31 2005**	 Sep 30 2005	 Dec 31 2004	Year Ended **Dec 31 2005**	 Dec 31 2004
Interest expense as reported	**$ 28**	$ 38	$ 48	**$ 149**	$ 189
Realized risk management gain	**(1)**	-	(7)	**(9)**	(32)
	$ 27	$ 38	$ 41	**$ 140**	$ 157
Average effective interest rate	**5.6%**	6.0%	4.6%	**5.2%**	4.4%

As effective as commodity hedges are against reference commodity prices, a substantial portion of the derivative 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 December 31, 2005, the implied price differentials for the non-designated hedges for future years. The cash settlement amount of the risk management financial derivative instruments may vary materially 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 mark-to-market value at December 31, 2005. Due to the dramatic increase in crude oil and natural gas forward pricing in 2005, the Company recorded a $925 million ($607 million after tax) unrealized loss on its risk management activities for the year ended December 31, 2005, net of an $825 million ($583 million after tax) unrealized gain for the three months ended December 31, 2005.

In addition to the risk management liability recognized on the balance sheet at December 31, 2005, the net unrecognized liability related to the fair value of derivative financial instruments designated as hedges was $990 million (December 31, 2004 – net unrecognized asset of $33 million).

Details related to outstanding derivative financial instruments at December 31, 2005 are disclosed in note 9 to the Company's unaudited interim consolidated financial statements as at December 31, 2005.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Dec 31 2005**	 Sep 30 2005	 Dec 31 2004	Year Ended **Dec 31 2005**	 Dec 31 2004
Realized foreign exchange (gain) loss	**$ (16)**	$ 5	$ 16	**$ (29)**	$ 3
Unrealized foreign exchange loss (gain)	**5**	(124)	(77)	**(103)**	(94)
	$ (11)	$ (119)	$ (61)	**$ (132)**	$ (91)

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 was the result of a foreign exchange gain on the repayment of the Company's preferred securities. In addition, net foreign exchange gains were realized on foreign exchange rate fluctuations on working capital items denominated in US dollars or UK pounds sterling. Unrealized foreign exchange loss (gain) is related to the fluctuation of the Canadian dollar in relation to the US dollar with respect to the US dollar debt and working capital denominated in US dollars or UK pounds sterling. The Canadian dollar ended the year at US$0.8577 compared to US$0.8308 at December 31, 2004 (September 30, 2005 - US$0.8613).

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

	Three Months Ended			Year Ended	
($ millions, except income tax rates)	**Dec 31 2005**	Sep 30 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Taxes other than income tax					
Current	**$ 50**	$ 75	$ 47	**$ 203**	$ 210
Deferred	**1**	(14)	(32)	**(9)**	(45)
	$ 51	$ 61	$ 15	**$ 194**	$ 165
Current income tax					
North America – Current income tax	**$ 2**	$ 20	$ 1	**$ 82**	$ 89
North America – Large corporations tax	**5**	5	5	**16**	11
North Sea	**31**	57	(16)	**155**	2
Offshore West Africa	**19**	6	3	**32**	13
Other	**1**	-	1	**1**	1
	$ 58	$ 88	$ (6)	**$ 286**	$ 116
Future income tax expense	**$ 514**	$ 18	$ 258	**$ 353**	$ 474
Effective income tax rate	**34.1%**	41.3%	30.4%	**37.8%**	29.6%

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.

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships, with the related income taxes payable in a subsequent year. North America 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 year and the three months ended December 31, 2005 increased from the comparable periods in 2004 due mainly to higher realized product prices, increased production volumes and the current deductibility of acquired tax pools in the UK in 2004. In November 2005 the UK government announced plans to double the supplementary charge on profits from UK North Sea crude oil and natural gas production to 20%. The increased North Sea supplementary charge, which will be effective in 2006, takes the Company's income tax rate in the North Sea from 40% to in excess of 50%. The supplementary charge excludes any deduction for financing costs. A charge has not been reflected in 2005 net earnings as the proposed change in UK tax law was not drafted in legislative form and tabled in Parliament at year end. The Company anticipates that this rate change will result in a charge to 2006 net earnings in the amount of $111 million.

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 [1]

($ millions)	Three Months Ended Dec 31 2005	Three Months Ended Sep 30 2005	Three Months Ended Dec 31 2004	Year Ended Dec 31 2005	Year Ended Dec 31 2004
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions [2]	**$ 19**	$ -	$ 761	**$ (320)**	$ 1,835
Land acquisition and retention	**97**	69	13	**254**	120
Seismic evaluations	**40**	31	21	**132**	89
Well drilling, completion and equipping	**629**	431	359	**2,000**	1,394
Pipeline and production facilities	**314**	266	185	**1,295**	821
Total net reserve replacement expenditures	**1,099**	797	1,339	**3,361**	4,259
Horizon Oil Sands Project:					
Phase 1 construction costs	**506**	432	-	**1,329**	-
Capitalized interest and other	**51**	20	58	**170**	291
Total Horizon Oil Sands Project	**557**	452	58	**1,499**	291
Midstream	**1**	(1)	11	**4**	16
Abandonments [3]	**16**	19	5	**46**	32
Head office	**6**	5	8	**22**	35
Total net capital expenditures	**$ 1,679**	$ 1,272	$ 1,421	**$ 4,932**	$ 4,633
By segment					
North America	**$ 862**	$ 618	$ 1,141	**$ 2,530**	$ 3,355
North Sea	**118**	100	87	**387**	608
Offshore West Africa	**119**	79	110	**439**	295
Other	**-**	-	1	**5**	1
Horizon Oil Sands Project	**557**	452	58	**1,499**	291
Midstream	**1**	(1)	11	**4**	16
Abandonments [3]	**16**	19	5	**46**	32
Head office	**6**	5	8	**22**	35
Total	**$ 1,679**	$ 1,272	$ 1,421	**$ 4,932**	$ 4,633

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

(2) Includes Business Combinations.

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

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 in 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 year ended December 31, 2005 were $4,932 million compared to $4,633 million for the year ended December 31, 2004. During 2005, the Company continued to make significant progress on its larger, future-growth projects, most notably the Horizon Oil Sands Project, while maintaining its focus on existing assets. The Company drilled a total of 1,882 net wells during the year consisting of 890 natural gas wells, 627 crude oil wells, 248 stratigraphic test and service wells, and 117 wells that were dry. This compared to 1,449 net wells drilled for the year ended December 31, 2004. The Company achieved an overall success rate of 93%, excluding stratigraphic test and service wells.

Net capital expenditures in the fourth quarter of 2005 were $1,679 million compared to $1,421 million in the comparable period in 2004 and $1,272 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 fourth quarter, the Company drilled a total of 525 net wells consisting of 279 natural gas wells, 190 crude oil wells, 33 stratigraphic test and service wells, and 23 wells that were dry. This compared to 333 net wells drilled in the fourth 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 83% of the total capital expenditures for the year ended December 31, 2005 compared to approximately 80% in 2004.

During 2005, the Company drilled 975 net natural gas wells, including 228 wells in Northeast British Columbia, 238 wells in the Northern Plains region, 166 wells in Northwest Alberta, and 343 wells in the Southern Plains region. The Company also drilled 642 net crude oil wells during 2005. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 360 heavy crude oil wells, 84 Pelican Lake crude oil wells, 109 thermal crude oil wells, and 7 light crude oil wells were drilled. Another 82 light crude oil wells were drilled during the year outside of the Northern Plains region. In the fourth quarter, the Company drilled 295 net natural gas wells and 191 net crude oil wells, consisting of 124 heavy crude oil wells, 27 Pelican Lake crude oil wells, 19 thermal crude oil wells and 21 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 projects, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. The Primrose North expansion was effectively completed in 2005 with total capital expenditures of approximately $300 million incurred. First steaming commenced in November 2005 and first oil production began in January 2006.

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. The development application was submitted to the Alberta Energy and Utilities Board in January 2006, with potential impacts associated with the use of bitumen as fuel being evaluated in the Environmental Impact Assessment. The Company expects construction to begin in 2007, with first steam scheduled for January 2009.

Development at Pelican Lake continued on track in 2005, with 84 wells being drilled and production increasing from 18 mbbls/d to 28 mbbls/d over the course of the year. The waterflood conversion project is on schedule with production response exceeding expectations. The Company plans to enhance the waterflood process through utilization of Polymer Flood technology. A Polymer Flood pilot has been in operation since May 2005 with positive results. The drilling of 150 horizontal wells is planned for 2006.

Above average temperatures have continued into 2006. Accordingly, the Company is leveraging its deep drilling inventory and optimizing drilling plans to adjust for road bans and/or site access issues. Despite these challenges, the Company still expects to complete the majority of its winter drilling program. However, the risk remains for an early spring breakup, which could significantly delay tie-in of many of these new wells. In the first quarter of 2006, the Company's overall drilling activity in North America is expected to be comprised of 495 natural gas wells and 90 crude oil wells excluding stratigraphic and service 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.

The Horizon Project continued on schedule and on budget. Specifically, as at December 31, 2005:

- Construction of the Horizon Project was approximately 19% complete;
- The detailed engineering work was on schedule with 3-D engineering models progressing as planned;
- The Company awarded $3.8 billion of contracts and purchase orders with a further C$600 million in various stages of the tender process; and
- Approximately 1,700 people were on site and functional.

Major activities for 2006 will include:

- Substantial completion of detailed engineering;
- Completion and setting of main piperack modules;
- Receiving and erecting of critical equipment;
- Beginning construction of ore preparation plant; and
- Substantial completion of foundations in each area.

First production of light, sweet Synthetic Crude Oil from Phase 1 construction is targeted to commence in the second half of 2008. The Horizon Project is in the early stages of construction.

North Sea

In the fourth quarter, the Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During the fourth quarter, 5.3 net wells were drilled, with an additional 2.9 net wells drilling at quarter-end.

In anticipation of the 2005 program of infill drilling, workovers and third party business on the T and B Blocks, the Company completed a major refurbishment of the Tiffany platform drilling rig, which is facilitating a two well program targeting unswept areas of the field. The first of these two wells was drilled and completed during the fourth quarter.

Production from the Kyle Field was diverted to the Banff FPSO in the third quarter of 2005. 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.

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 9, 2005 at approximately 30,000 bbl/d net to the Company. Upon completion of drilling additional wells in 2006, production levels are expected to achieve approximately 35,000 bbl/d net to the Company.

In East Espoir, two of the four infill wells scheduled for drilling were completed during 2005, with the remainder expected to be completed in 2006. 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 and production. The West Espoir drilling tower, which will facilitate development drilling of the reservoir, is on site and was installed in late 2005. This project is progressing on time and on budget with first crude oil expected in 2006, increasing to approximately 13,000 boe/d once fully developed.

The Company purchased a 90% interest in the Olowi PSC offshore Gabon in October 2005 and received approval of its development plan for this acquisition subsequent to year end. Development plans include a floating production, storage and offtake vessel handling input from two or three shallow-water producing platforms. Development is expected to begin late in 2006, with first oil expected late in 2008 at a rate of approximately 20,000 bbl/d.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2005**	Sep 30 2005	Dec 31 2004
Working capital deficit [1]	**$ 1,774**	$ 2,106	$ 652
Long-term debt	**$ 3,321**	$ 3,235	$ 3,538
Shareholders' equity			
Share capital	**$ 2,442**	$ 2,433	$ 2,408
Retained earnings	**5,804**	4,759	4,922
Foreign currency translation adjustment	**(9)**	(11)	(6)
Total	**$ 8,237**	$ 7,181	$ 7,324
Debt to cash flow [2]	**0.7x**	0.8x	1.0x
Debt to EBITDA [3]	**0.6x**	0.7x	0.9x
Debt to book capitalization [4]	**28.7%**	32.3%	33.8%
Debt to market capitalization	**9.7%**	10.8%	21.4%
After tax return on average common shareholders' equity [5]	**14.3%**	7.4%	21.4%
After tax return on average capital employed [6]	**10.4%**	5.8%	15.3%

(1) Calculated as current assets less current liabilities.

(2) Calculated as current and long-term debt; divided by cash flow from operations for the twelve month trailing period.

(3) Calculated as current and long-term debt; divided by earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities for the twelve month trailing period.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as net earnings as a percentage of average common shareholders' equity for the period.

(6) Calculated as net earnings plus after-tax interest expense; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period.

At December 31, 2005, the working capital deficit was $1,774 million and included the current portion of other long-term liabilities of $1,471 million, comprised of stock-based compensation of $629 million and the mark-to-market valuation of non-designated risk management financial derivative instruments of $842 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 may vary materially 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 mark-to-market value at December 31, 2005.

The Company is committed to maintaining a strong financial position. In 2005, strong operational results and high commodity prices resulted in debt to book capitalization levels of 28.7%. The Company believes it has the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of conventional crude oil and natural gas growth opportunities. The financing of Phase 1 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 December 31, 2005, such as Baobab, Primrose and West Espoir will provide identified growth in production volumes in 2006 through 2008, and will generate incremental free cash flows during this period.

In January 2005, the Board of Directors authorized the expansion of the Company's commodity 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 budgeted 2006 crude oil volumes have been hedged through the use of collars. In addition, approximately 60% of budgeted 2006 natural gas volumes have similarly been hedged through the use of collars.

Long-term debt

Long-term debt at December 31, 2005 amounted to $3,321 million. The debt to EBITDA ratio decreased to 0.6x and the debt to book capitalization decreased to 28.7% compared to a debt to EBITDA ratio of 0.9x and a debt to book capitalization of 33.8% in 2004. These ratios are currently below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 35% to 45%.

Operating facilities

As at December 31, 2005 the Company had in place unsecured syndicated bank credit facilities of $3,425 million, comprised of:

– a $100 million operating demand facility;
– a two-tranche revolving credit and term loan facility of $1,825 million; and
– a 5-year revolving and term loan facility of $1,500 million.

The first $1,000 million tranche of the $1,825 million facility 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. If not extended, the full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit and term loan facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. These facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2005, was 5.44% (2004 – 3.47%).

The Company also has an unsecured £15 million demand overdraft credit facility for the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, as at December 31, 2005 letters of credit aggregating $24 million have been issued.

At December 31, 2005, the Company had undrawn bank lines of credit of $3,285 million.

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 May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program.

In January 2006, the Company issued $400 million of debt securities maturing January 23, 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes
In December 2005, the Company repaid the US$125 million 7.69% senior unsecured notes. The 6.42% senior unsecured notes were repaid in May 2004.

The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009.

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 repayment premium of US$11 million as required under the Note Purchase Program.

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.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014.

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

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 December 31, 2005, there were 536,348,000 common shares outstanding. As at February 21, 2005, the Company had 537,156,000 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 December 31, 2005, the Company had purchased 850,000 common shares at an average price of $53.29 per common share for a total cost of $45 million.

On January 20, 2006 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 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007.

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 represented 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.

In February 2006, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.30 per common share for 2006.

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, as well as expenditures relating to asset retirement obligations. The Company has not entered into any contracts that would require consolidation under CICA Accounting Handbook, AcG-15, Consolidation of Variable Interest Entities. The following table summarizes the Company's commitments as at December 31, 2005:

($ millions)	2006	2007	2008	2009	2010	Thereafter
Product transportation and pipeline (1)	$ 195	$ 133	$ 148	$ 94	$ 85	$ 1,111
Offshore equipment operating lease	$ 51	$ 51	$ 52	$ 51	$ 51	$ 180
Offshore drilling	$ 132	$ 100	$ 35	$ -	$ -	$ -
Asset retirement obligations(2)	$ 82	$ 4	$ 4	$ 4	$ 7	$ 3,224
Long-term debt(3)	$ -	$ 161	$ 36	$ 36	$ -	$ 2,966
Other(4)	$ 61	$ 62	$ 21	$ 29	$ 23	$ 8

(1) During the year, the Company entered into a 25 year pipeline transportation agreement commencing in 2008, related to future crude oil production. The agreement is renewable for successive 10-year periods at the Company's option. During the initial term, annual toll payments before operating costs will be approximately $35 million.

(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, production platforms and pipelines, based on current legislation and industry operating practices.

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

(4) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

Total construction 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 construction costs for Phase 1 of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Company believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

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 will cease once construction is substantially complete and the Horizon Project is ready for its intended use. For the year ended December 31, 2005, pre-tax interest of $72 million was capitalized to the Horizon Project.

SENSITIVITY ANALYSIS [1]

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the fourth 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	$ 113	$ 0.21	$ 79	$ 0.15
Including financial derivatives	$ 60	$ 0.11	$ 40	$ 0.07
Natural gas – AECO C$0.10/mcf [2]				
Excluding financial derivatives	$ 38	$ 0.07	$ 24	$ 0.05
Including financial derivatives	$ 14	$ 0.03	$ 8	$ 0.01
Volume changes				
Crude oil – 10,000 bbl/d	$ 104	$ 0.19	$ 53	$ 0.10
Natural gas – 10 mmcf/d	$ 32	$ 0.06	$ 17	$ 0.03
Foreign currency rate change				
$0.01 change in C$ in relation to US$[2]	$ 82-84	$ 0.15-0.16	$ 32-33	$ 0.06
Interest rate change - 1%	$ 7	$ 0.01	$ 7	$ 0.01

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

(2) For details of financial instruments in place, refer to note 9 of the Company's unaudited interim consolidated financial statements.

OTHER OPERATING HIGHLIGHTS

NETBACK ANALYSIS

($/boe)[1]	Three Months Ended Dec 31 2005	Three Months Ended Sep 30 2005	Three Months Ended Dec 31 2004	Year Ended Dec 31 2005	Year Ended Dec 31 2004
Sales price[2]	**$ 56.08**	$ 54.87	$ 38.51	**$ 48.77**	$ 38.45
Royalties	**8.01**	7.84	5.21	**6.82**	5.37
Production expense[3]	**7.93**	8.56	7.61	**8.21**	7.35
Netback	**40.14**	38.47	25.69	**33.74**	25.73
Midstream contribution[3]	**(0.25)**	(0.26)	(0.27)	**(0.26)**	(0.26)
Administration[4]	**0.68**	0.75	0.72	**0.75**	0.66
Interest, net	**0.53**	0.73	1.00	**0.74**	1.01
Realized risk management loss	**9.07**	7.12	3.58	**5.13**	2.52
Realized foreign exchange (gain) loss	**(0.29)**	0.10	0.33	**(0.15)**	0.02
Taxes other than income tax - current	**0.93**	1.46	0.98	**1.01**	1.12
Current income tax - North America	**0.04**	0.39	0.02	**0.41**	0.47
Current income tax - Large corporations tax	**0.11**	0.07	0.09	**0.08**	0.05
Current income tax - North Sea	**0.59**	1.11	(0.32)	**0.77**	0.01
Current income tax - Offshore West Africa	**0.35**	0.12	0.07	**0.17**	0.07
Current income tax - other	**0.02**	-	0.03	**0.01**	0.01
Cash flow	**$ 28.36**	$ 26.88	$ 19.46	**$ 25.08**	$ 20.05

(1) Amounts expressed on a per unit basis are based on sales volumes.

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

(3) Excluding intersegment elimination.

(4) Restated to conform to current year presentation.

FINANCIAL STATEMENTS

Consolidated balance sheets

(millions of Canadian dollars, unaudited)		**Dec 31 2005**		Dec 31 2004
ASSETS				
Current assets				
Cash	**$**	**18**	$	28
Accounts receivable and other		**1,546**		1,055
Future income tax		**487**		83
Current portion of other long-term assets (note 2)		**-**		34
		2,051		1,200
Property, plant and equipment, net		**19,694**		17,064
Other long-term assets (note 2)		**107**		108
	$	**21,852**	$	18,372
LIABILITIES				
Current liabilities				
Accounts payable	**$**	**573**	$	379
Accrued liabilities		**1,781**		1,019
Current portion of long-term debt (note 3)		**-**		194
Current portion of other long-term liabilities (note 4)		**1,471**		260
		3,825		1,852
Long-term debt (note 3)		**3,321**		3,538
Other long-term liabilities (note 4)		**1,434**		1,208
Future income tax		**5,035**		4,450
		13,615		11,048
SHAREHOLDERS' EQUITY				
Share capital (note 6)		**2,442**		2,408
Retained earnings		**5,804**		4,922
Foreign currency translation adjustment (note 7)		**(9)**		(6)
		8,237		7,324
	$	**21,852**	$	18,372

Commitments (note 10)

Consolidated statements of earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2005	Three Months Ended Dec 31 2004	Year Ended Dec 31 2005	Year Ended Dec 31 2004
Revenue	**$ 3,032**	$ 1,969	**$ 10,107**	$ 7,547
Less: royalties	**(421)**	(255)	**(1,366)**	(1,011)
Revenue, net of royalties	**2,611**	1,714	**8,741**	6,536
Expenses				
Production	**423**	377	**1,663**	1,400
Transportation	**66**	71	**270**	250
Depletion, depreciation and amortization	**550**	501	**2,013**	1,769
Asset retirement obligation accretion (note 4)	**16**	16	**69**	51
Administration	**36**	36	**151**	125
Stock-based compensation (note 4)	**125**	24	**723**	249
Interest, net	**28**	48	**149**	189
Risk management activities (note 9)	**(349)**	(142)	**1,952**	434
Foreign exchange gain	**(11)**	(61)	**(132)**	(91)
	884	870	**6,858**	4,376
Earnings before taxes	**1,727**	844	**1,883**	2,160
Taxes other than income tax	**51**	15	**194**	165
Current income tax expense (recovery) (note 5)	**58**	(6)	**286**	116
Future income tax expense (note 5)	**514**	258	**353**	474
Net earnings	**$ 1,104**	$ 577	**$ 1,050**	$ 1,405
Net earnings per common share (note 8)				
Basic	**$ 2.06**	$ 1.07	**$ 1.96**	$ 2.62
Diluted	**$ 2.06**	$ 1.06	**$ 1.95**	$ 2.60

Consolidated statements of retained earnings

(millions of Canadian dollars, unaudited)	Year Ended Dec 31 2005	Year Ended Dec 31 2004
Balance – beginning of year	**$ 4,922**	$ 3,650
Net earnings	**1,050**	1,405
Dividends on common shares (note 6)	**(127)**	(107)
Purchase of common shares under Normal Course Issuer Bid (note 6)	**(41)**	(26)
Balance – end of year	**$ 5,804**	$ 4,922

Consolidated statements of cash flows

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2005	Three Months Ended Dec 31 2004	Year Ended Dec 31 2005	Year Ended Dec 31 2004
Operating activities				
Net earnings	**$ 1,104**	$ 577	**$ 1,050**	$ 1,405
Non-cash items				
Depletion, depreciation and amortization	**550**	501	**2,013**	1,769
Asset retirement obligation accretion	**16**	16	**69**	51
Stock-based compensation	**125**	24	**723**	249
Unrealized risk management activities	**(825)**	(317)	**925**	(40)
Unrealized foreign exchange loss (gain)	**5**	(77)	**(103)**	(94)
Deferred petroleum revenue tax (recovery)	**1**	(32)	**(9)**	(45)
Future income tax expense	**514**	258	**353**	474
Deferred charges	**2**	(36)	**(31)**	(33)
Abandonment expenditures	**(16)**	(5)	**(46)**	(32)
Net change in non-cash working capital	**(68)**	37	**(147)**	(14)
	1,408	946	**4,797**	3,690
Financing activities				
Issue (repayment) of bank credit facilities	**74**	(386)	**(435)**	357
Issue (repayment) of medium-term notes	**-**	-	**400**	(125)
Repayment of senior unsecured notes	**(194)**	-	**(194)**	(54)
Repayment of preferred securities	**-**	-	**(107)**	-
Issue of US debt securities	**-**	830	**-**	830
Repayment of obligations under capital leases	**-**	-	**-**	(7)
Issue of common shares	**3**	2	**9**	24
Purchase of common shares	**(29)**	-	**(45)**	(33)
Dividends on common shares	**(32)**	(27)	**(121)**	(101)
Net change in non-cash working capital	**3**	4	**19**	6
	(175)	423	**(474)**	897
Investing activities				
Expenditures on property, plant and equipment	**(1,764)**	(1,420)	**(5,340)**	(4,582)
Net proceeds on sale of property, plant and equipment	**101**	3	**454**	7
Net expenditures on property, plant and equipment	**(1,663)**	(1,417)	**(4,886)**	(4,575)
Net proceeds on sale of other assets	**-**	-	**11**	-
Net change in non-cash working capital	**436**	64	**542**	(88)
	(1,227)	(1,353)	**(4,333)**	(4,663)
Increase (decrease) in cash	**6**	16	**(10)**	(76)
Cash – beginning of period	**12**	12	**28**	104
Cash – end of period	**$ 18**	$ 28	**$ 18**	$ 28
Interest paid	**$ 48**	$ 42	**$ 200**	$ 192
Taxes paid				
Taxes other than income tax	**$ 21**	$ 27	**$ 192**	$ 151
Current income tax	**$ 46**	$ 10	**$ 238**	$ 67

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 will cease once construction is substantially complete and the Horizon Project is ready for its intended use. For the year ended December 31, 2005, pre-tax interest of $72 million was capitalized to the Horizon Project.

Comparative figures

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

2. OTHER LONG–TERM ASSETS

	Dec 31 2005	Dec 31 2004
Deferred charges and other	**$ 107**	$ 76
Risk management (note 9)	**-**	66
	107	142
Less: current portion	**-**	34
	$ 107	$ 108

3. LONG–TERM DEBT

	Dec 31 2005	Dec 31 2004
Bank credit facilities		
Bankers' acceptances	**$ 122**	$ -
US dollar bankers' acceptances (2005 –US$nil, 2004 – US$471 million)	**-**	557
Medium-term notes	**525**	125
Senior unsecured notes (2005 – US$93 million, 2004 – US$218 million)	**108**	306
Preferred securities (2005 – US$nil, 2004 – US$80 million)	**-**	96
US dollar debt securities (2005 – US$2,200 million, 2004 – US$2,200 million)	**2,566**	2,648
	3,321	3,732
Less: current portion of long-term debt	**-**	194
	$ 3,321	$ 3,538

Bank credit facilities

As at December 31, 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.

The Company also has an unsecured £15 million demand overdraft credit facility related to the Company's North Sea operations. At December 31, 2005 there were no amounts drawn on this facility.

In addition to the outstanding debt, letters of credit aggregating $24 million were also outstanding at December 31, 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 January 2006, the Company issued $400 million of debt securities maturing January 2013, bearing interest at 4.50%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. After issuing these securities, the Company has $1.6 billion remaining on its $2 billion shelf prospectus filed in August 2005 that allows for the issue of medium-term notes in Canada until September 2007. If issued, these securities will bear interest as determined at the date of issuance.

Senior unsecured notes

In December 2005 the Company repaid the US$125 million 7.69% senior unsecured notes.

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

	Dec 31 2005	Dec 31 2004
Asset retirement obligations	**$ 1,112**	$ 1,119
Stock-based compensation	**891**	323
Risk management (note 9)	**885**	26
Other	**17**	-
	2,905	1,468
Less: current portion	**1,471**	260
	$ 1,434	$ 1,208

Asset retirement obligations

At December 31, 2005, the Company's total estimated undiscounted cost to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was approximately $3,325 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 6.8%. A reconciliation of the discounted asset retirement obligations is as follows:

	Year Ended Dec 31, 2005	Year Ended Dec 31, 2004
Asset retirement obligations		
Balance – beginning of year	**$ 1,119**	$ 897
Liabilities incurred	**47**	339
Liabilities settled	**(46)**	(32)
Asset retirement obligation accretion	**69**	51
Revision of estimates	**(56)**	(86)
Foreign exchange	**(21)**	(50)
Balance – end of year	**$ 1,112**	$ 1,119

The Company's pipelines have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations 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 potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next 12-month period if all vested options are surrendered for cash settlement.

	Year Ended Dec 31, 2005	Year Ended Dec 31, 2004
Stock-based compensation		
Balance – beginning of year	**$ 323**	$ 171
Stock-based compensation provision	**723**	249
Current year payment for options surrendered	**(227)**	(80)
Transferred to common shares	**(29)**	(38)
Capitalized to Horizon Project	**101**	21
Balance – end of year	**891**	323
Less: current portion	**629**	243
	$ 262	$ 80

5. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Current income tax expense (recovery)				
Current income tax – North America	**$ 2**	$ 1	**$ 82**	$ 89
Large corporations tax – North America	**5**	5	**16**	11
Current income tax – North Sea	**31**	(16)	**155**	2
Current income tax – Offshore West Africa	**19**	3	**32**	13
Current income tax – Other	**1**	1	**1**	1
	58	(6)	**286**	116
Future income tax expense	**514**	258	**353**	474
Income tax expense	**$ 572**	$ 252	**$ 639**	$ 590

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. The legislation received royal assent in December 2005. In the first 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**	Year Ended Dec 31, 2005 **Number of shares** (thousands)[1]		**Amount**
Balance – beginning of year	**536,361**	**$**	**2,408**
Issued upon exercise of stock options	**837**		**9**
Previously recognized liability on stock options exercised for common shares	**-**		**29**
Purchase of shares under Normal Course Issuer Bid	**(850)**		**(4)**
Balance – end of year	**536,348**	**$**	**2,442**

(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 December 31, 2005, the Company had purchased 850,000 common shares at an average price of $53.29 per common share, for a total cost of $45 million. Retained earnings was reduced by $41 million, representing the excess of the purchase price of the common shares over their stated value.

In January 2006 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 26,852,545 common shares or 5% of the outstanding common shares of the Company on the date of the announcement, during the 12-month period beginning January 24, 2006 and ending January 23, 2007.

Dividend policy

In February 2006, the Board of Directors set the regular quarterly dividend at $0.075 per common share. 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

	Year Ended Dec 31, 2005		
	Stock options (thousands)(1)		**Weighted average exercise price**(1)
Outstanding – beginning of year	**32,522**	**$**	**12.37**
Granted	**7,959**	**$**	**32.51**
Exercised for common shares	**(837)**	**$**	**9.81**
Surrendered for cash settlement	**(7,523)**	**$**	**10.49**
Forfeited	**(1,611)**	**$**	**19.36**
Outstanding – end of year	**30,510**	**$**	**17.79**
Exercisable – end of year	**8,677**	**$**	**11.21**

(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.

		Dec 31 2005
Balance – beginning of year	**$**	**(6)**
Unrealized gain on translation of net investment		**(12)**
Hedge of net investment with US dollar denominated debt (net of tax)		**9**
Balance – end of year	**$**	**(9)**

8. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2005	Dec 31 2004[1]	**Dec 31 2005**	Dec 31 2004[1]
Weighted average common shares outstanding (thousands)				
Basic	**536,482**	537,002	**536,650**	536,223
Assumed settlement of preferred securities with common shares	**-**	3,900	**1,775**	4,461
Diluted	**536,482**	540,902	**538,425**	540,684
Net earnings	**$ 1,104**	$ 577	**$ 1,050**	$ 1,405
Interest on preferred securities, net of tax	**-**	1	**4**	5
Revaluation of preferred securities, net of tax	**-**	(2)	**(2)**	(4)
Diluted net earnings	**$ 1,104**	$ 576	**$ 1,052**	$ 1,406
Net earnings per common share				
Basic	**$ 2.06**	$ 1.07	**$ 1.96**	$ 2.62
Diluted	**$ 2.06**	$ 1.06	**$ 1.95**	$ 2.60

(1) Restated to reflect two-for-one common share split in May 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 December 31, 2005, the estimated fair values of non-designated financial derivatives was comprised as follows:

Asset/(liability)	Risk management mark-to-market	Deferred revenue
Balance – beginning of year	**$ 66**	**$ (26)**
Net cost of put options outstanding at December 31, 2005	**190**	**-**
Net change in fair value of financial instruments outstanding as at December 31, 2005	**(943)**	**-**
Amortization of deferred revenue	**-**	**18**
	(687)	**(8)**
Add: Put premium financing obligations	**(190)**	**-**
Balance – end of year	**(877)**	**(8)**
Less: current portion	**834**	**8**
	$ (43)	**$ -**

The Company has negotiated payment of put option premiums with various counter-parties at the time of actual settlement of the respective options. These obligations have been reflected in the risk management liability at December 31, 2005.

Net losses (gains) from risk management activities for the periods ended December 31 were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Net realized risk management loss	**$ 476**	$ 175	**$ 1,027**	$ 474
Net unrealized risk management mark-to-market (gain) loss	**(825)**	(317)	**925**	(40)
	$ (349)	$ (142)	**$ 1,952**	$ 434

As at December 31, 2005, the net unrecognized liability related to the estimated fair values of derivative financial instruments designated as hedges was $990 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 December 31, 2005:

	Remaining term			Volume	Average price			Index
Crude oil								
Oil price collars								
	Jan 2006	–	Dec 2006	250,000 bbl/d	US$40.40	–	US$57.71	WTI
	Jan 2006	–	Dec 2006	22,000 bbl/d	C$46.53	–	C$58.67	WTI
Oil puts[(1)]								
	Mar 2006	–	Jul 2006	55,000 bbl/d			US$40.00	WTI
	Aug 2006	–	Dec 2006	51,000 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

(1) Subsequent to year end, the Company settled 17,000 bbl/d of the US$40.00 put options for 2006 and purchased 100,000 bbl/d of US$50.00 put options for 2007.

	Remaining term			Volume	Average price			Index
Natural gas								
AECO collars								
	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	808,000 GJ/d	C$6.87	–	C$14.84	AECO
	Jan 2007	–	Mar 2007	700,000 GJ/d	C$7.50	–	C$18.80	AECO

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Jan 2006	–	Jan 2007	US$200[2]	7.20%	LIBOR[1] + 2.23%
	Jan 2006	–	Oct 2012	US$350	5.45%	LIBOR[1] + 0.81%
	Jan 2006	–	Dec 2014	US$350	4.90%	LIBOR[1] + 0.38%
Swaps – floating to fixed	Jan 2006	–	Mar 2007	C$6	7.36%	CDOR[3]

(1) London Interbank Offered Rate.

(2) Subsequent to year end the Company received approximately $1 million in settlement of the 7.20% fixed to floating rate swap.

(3) Canadian Deposit Overnight Rate.

10. COMMITMENTS

The Company has committed to certain payments as follows:

		2006		2007		2008		2009		2010		Thereafter
Product transportation and pipeline[1]	$	195	$	133	$	148	$	94	$	85	$	1,111
Offshore equipment operating lease	$	51	$	51	$	52	$	51	$	51	$	180
Offshore drilling	$	132	$	100	$	35	$	-	$	-	$	-
Asset retirement obligations[2]	$	82	$	4	$	4	$	4	$	7	$	3,224
Other[3]	$	61	$	62	$	21	$	29	$	23	$	8

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

(2) Represents management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, production platforms and pipelines, based on current legislation and industry operating practices.

(3) Consists of future expenditures related primarily to office lease, electricity and crude oil processing.

Total construction costs for the three phases of the Horizon Project development are expected to be approximately $10.8 billion, before non-construction costs including capitalized interest and stock based compensation. The Board of Directors has approved the construction costs for Phase 1 of the Horizon Project, which are expected to be $6.8 billion, including a contingency fund of $700 million, with $1.3 billion incurred in 2005, $2.6 billion to be incurred in 2006 and $2.9 billion to be incurred in 2007 and 2008.

11. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America Three Months Ended Dec 31		North America Year Ended Dec 31		North Sea Three Months Ended Dec 31		North Sea Year Ended Dec 31		Offshore West Africa Three Months Ended Dec 31		Offshore West Africa Year Ended Dec 31	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**2,376**	1,547	**7,932**	5,979	**371**	358	**1,659**	1,317	**280**	55	**485**	222
Less: royalties	**(413)**	(254)	**(1,350)**	(1,003)	**(1)**	-	**(3)**	(2)	**(7)**	(1)	**(13)**	(6)
Revenue, net of royalties	**1,963**	1,293	**6,582**	4,976	**370**	358	**1,656**	1,315	**273**	54	**472**	216
Segmented expenses												
Production	**322**	259	**1,211**	976	**68**	104	**379**	370	**26**	9	**53**	36
Transportation	**72**	74	**287**	256	**4**	7	**20**	32	**-**	-	**-**	-
Depletion, depreciation and amortization	**412**	407	**1,595**	1,444	**70**	81	**306**	265	**66**	11	**104**	53
Asset retirement obligation accretion	**9**	7	**34**	28	**6**	8	**34**	22	**1**	1	**1**	1
Realized risk management activities	**432**	134	**870**	362	**44**	41	**157**	112	**-**	-	**-**	-
Total segmented expenses	**1,247**	881	**3,997**	3,066	**192**	241	**896**	801	**93**	21	**158**	90
Segmented earnings before the following	**716**	412	**2,585**	1,910	**178**	117	**760**	514	**180**	33	**314**	126
Non-segmented expenses												
Administration												
Stock-based compensation												
Interest, net												
Unrealized risk management activities												
Foreign exchange gain												
Total non-segmented expenses												
Earnings before taxes												
Taxes other than income tax												
Current income tax expense (recovery)												
Future income tax expense												
Net earnings												

(millions of Canadian dollars, unaudited)	Midstream				Other			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**21**	18	**77**	68	**(5)**	1	**(5)**	1
Less: royalties	**-**	-	**-**	-	**-**	-	**-**	-
Revenue, net of royalties	**21**	18	**77**	68	**(5)**	1	**(5)**	1
Segmented expenses								
Production	**8**	5	**24**	20	**-**	-	**-**	-
Transportation	**-**	-	**-**	-	**-**	-	**-**	-
Depletion, depreciation and amortization	**2**	2	**8**	7	**-**	-	**-**	-
Asset retirement obligation accretion	**-**	-	**-**	-	**-**	-	**-**	-
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-
Total segmented expenses	**10**	7	**32**	27	**-**	-	**-**	-
Segmented earnings before the following	**11**	11	**45**	41	**(5)**	1	**(5)**	1
Non-segmented expenses								
Administration								
Stock-based compensation								
Interest, net								
Unrealized risk management activities								
Foreign exchange gain								
Total non-segmented expenses								
Earnings before taxes								
Taxes other than income tax								
Current income tax expense (recovery)								
Future income tax expense								
Net earnings								

(millions of Canadian dollars, unaudited)	Inter-segment Elimination Three Months Ended Dec 31		Inter-segment Elimination Year Ended Dec 31		Total Three Months Ended Dec 31		Total Year Ended Dec 31	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004
Segmented revenue	**(11)**	(10)	**(41)**	(40)	**3,032**	1,969	**10,107**	7,547
Less: royalties	**-**	-	**-**	-	**(421)**	(255)	**(1,366)**	(1,011)
Revenue, net of royalties	**(11)**	(10)	**(41)**	(40)	**2,611**	1,714	**8,741**	6,536
Segmented expenses								
Production	**(1)**	-	**(4)**	(2)	**423**	377	**1,663**	1,400
Transportation	**(10)**	(10)	**(37)**	(38)	**66**	71	**270**	250
Depletion, depreciation and amortization	**-**	-	**-**	-	**550**	501	**2,013**	1,769
Asset retirement obligation accretion	**-**	-	**-**	-	**16**	16	**69**	51
Realized risk management activities	**-**	-	**-**	-	**476**	175	**1,027**	474
Total segmented expenses	**(11)**	(10)	**(41)**	(40)	**1,531**	1,140	**5,042**	3,944
Segmented earnings before the following	**-**	-	**-**	-	**1,080**	574	**3,699**	2,592
Non-segmented expenses								
Administration					**36**	36	**151**	125
Stock-based compensation					**125**	24	**723**	249
Interest, net					**28**	48	**149**	189
Unrealized risk management activities					**(825)**	(317)	**925**	(40)
Foreign exchange gain					**(11)**	(61)	**(132)**	(91)
Total non-segmented expenses					**(647)**	(270)	**1,816**	432
Earnings before taxes					**1,727**	844	**1,883**	2,160
Taxes other than income tax					**51**	15	**194**	165
Current income tax expense (recovery)					**58**	(6)	**286**	116
Future income tax expense					**514**	258	**353**	474
Net earnings					**1,104**	577	**1,050**	1,405

Net additions to property, plant and equipment

	2005			2004		
	Cash Expenditures	**Non-Cash/ Fair Value Changes(1)**	**Capitalized Costs**	Cash Expenditures	Non-Cash/ Fair Value Changes(1)	Capitalized Costs
North America	**$ 2,530**	**$ (22)**	**$ 2,508**	$ 3,329	$ 508	$ 3,837
North Sea	**387**	**(136)**	**251**	608	172	780
Offshore West Africa	**439**	**27**	**466**	295	-	295
Other	**5**	**-**	**5**	1	-	1
Horizon Oil Sands Project	**1,499**	**-**	**1,499**	291	-	291
Midstream	**4**	**-**	**4**	16	-	16
Head office	**22**	**-**	**22**	35	-	35
	$ 4,886	**$ (131)**	**$ 4,755**	$ 4,575	$ 680	$ 5,255

(1) Asset retirement obligations, future income tax adjustments on non tax base assets, and other fair value adjustments.

	Property, plant and equipment		Total assets	
	Dec 31 2005	Dec 31 2004	**Dec 31 2005**	Dec 31 2004
Segmented assets				
North America	**$ 14,310**	$ 13,394	**$ 15,939**	$ 14,390
North Sea	**1,681**	1,823	**1,950**	2,036
Offshore West Africa	**1,253**	901	**1,371**	914
Other	**13**	8	**30**	35
Horizon Oil Sands Project	**2,169**	672	**2,239**	672
Midstream	**203**	209	**258**	268
Head office	**65**	57	**65**	57
	$ 19,694	$ 17,064	**$ 21,852**	$ 18,372

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 2005. 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 December 31, 2005:	
Interest coverage (times)	
Net earnings[(1)]	8.3x
Cash flow from operations[(2)]	24.8x

(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 both proved, and proved and probable reserves, as well as related 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.

Canadian Natural retains a qualified independent reserves evaluator to evaluate 100% of the Company's proved and probable oil sands mining reserves and prepare Evaluation Reports on these reserves. The Horizon Oil Sands mining reserves have been evaluated under SEC Industry Guide 7 and are disclosed separately from conventional oil and gas reserves disclosure.

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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time on Thursday, February 23, 2006. The North American conference call number is 1-866-902-2211 and the outside North American conference call number is 001-416-695-5261. Please call in about 10 minutes before the starting time in order to be patched into the call. The conference call will also be broadcast live on the internet and may be accessed through the Canadian Natural Resources website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Standard Time on Thursday, March 2, 2006. To access the postview in North America, dial 1-888-509-0082. Those outside of North America, dial 001-416-695-5275.

WEBCAST

This call is being webcast by Vcall and can be accessed on Canadian Natural's website at www.cnrl.com/investor_info/calendar.html.

The webcast is also being distributed over PrecisionIR's Investor Distribution Network to both institutional and individual investors. Investors can listen to the call through www.vcall.com or by visiting any of the investor sites in PrecisionIR's Individual Investor Network.

2006 FIRST QUARTER RESULTS

2006 first quarter results are scheduled for release on Thursday, May 4, 2006. A conference call will be held on that day at 9:00 a.m. Mountain Daylight Time, 11:00 a.m. Eastern Daylight Time.

For further information, please contact:

ANNUAL GENERAL MEETING

Canadian Natural Resources Limited's Annual General Meeting of the Shareholders will be held on Thursday, May 4, 2006 at 3:00 p.m. Mountain Daylight Time at the Metropolitan Conference Centre, Calgary, Alberta. All shareholders are invited to attend.

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JOHN G. LANGILLE
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