Canadian Natural

PRESS RELEASE

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2010 FOURTH QUARTER AND YEAR END RESULTS CALGARY, ALBERTA – MARCH 3, 2011 – FOR IMMEDIATE RELEASE

"Canadian Natural reached a milestone in 2010 as we achieved an overall record yearly production level of over 632,000 barrels per day of oil equivalent. In addition, we increased our total proved plus probable company gross reserves by 9% to 6.9 billion barrels of oil equivalent, replacing 341% of our 2010 production and providing us a strong base of reserves with significant upside potential for years to come. Finally, to demonstrate confidence in our growth and sustainability, the Board of Directors has increased the quarterly dividend to $0.09 per common share, a 20% increase from 2010, marking this as the eleventh year of consecutive increases for the Company." Canadian Natural's Chairman, Allan Markin stated.

John Langille, Vice-Chairman of Canadian Natural summarized, "Over the last two years our core business has generated approximately $6.0 billion of free cash flow allowing us to make discretionary acquisitions of $1.9 billion while at the same time reducing debt by $4.5 billion, resulting in a debt to book capitalization of 29%. The Company's ability to generate strong cash flow enables us to manage the reduced cash flow we will experience from Horizon in 2011 without affecting our ongoing operations or capital expenditure plans. Our focus on financial discipline ensures we maintain a strong balance sheet going forward."

With regards to Canadian Natural's 2010 operating year, Steve Laut, President commented, "2010 was a strong year as we capitalized on the balance in our asset base through the effective allocation of capital to projects that provide the highest returns. We are in a solid position as the project portfolio continues to build strength and optionality preparing us to provide growth through a variety of commodity price scenarios."

HIGHLIGHTS

	Three Months Ended			Year End Results	
($ millions, except as noted)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009(1)	**Dec 31 2010**	Dec 31 2009(1)
Net earnings (loss)	**$ (416)**	$ 580	$ 455	**$ 1,697**	$ 1,580
Per common share, basic and diluted	**$ (0.38)**	$ 0.53	$ 0.42	**$ 1.56**	$ 1.46
Adjusted net earnings from operations (2)	**$ 618**	$ 606	$ 667	**$ 2,570**	$ 2,689
Per common share, basic and diluted	**$ 0.57**	$ 0.55	$ 0.61	**$ 2.36**	$ 2.48
Cash flow from operations (3)	**$ 1,641**	$ 1,545	$ 1,703	**$ 6,321**	$ 6,090
Per common share, basic and diluted	**$ 1.51**	$ 1.42	$ 1.57	**$ 5.81**	$ 5.62
Capital expenditures, net of dispositions	**$ 1,947**	$ 914	$ 694	**$ 5,506**	$ 2,997
Daily production, before royalties					
Natural gas (MMcf/d)	**1,252**	1,258	1,250	**1,243**	1,315
Crude oil and NGLs (bbl/d)	**438,835**	411,585	366,451	**424,985**	355,463
Equivalent production (BOE/d)	**647,441**	621,284	574,857	**632,191**	574,730

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in Management's Discussion and Analysis ("MD&A").

(3) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

Annual

- During 2010, total crude oil and NGLs production increased by 20% from 2009 to average 424,985 bbl/d reflecting increased crude oil drilling demonstrating the Company's flexibility in allocating capital to higher return crude oil projects as well as increased production volumes from the Company's thermal and Horizon Oil Sands ("Horizon") operations.

- Total natural gas production for the year averaged 1,243 MMcf/d, a decrease of 5% from 2009. Production volumes were targeted to decrease from 2009 due to the Company's strategic decision to reduce capital re-investment in natural gas resulting in a 16% reduction in North America natural gas net drilling activity.

- Net earnings in 2010 increased to $1.7 billion compared to $1.6 billion in 2009. Net earnings for 2010 included net unrealized after-tax expenses related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation, a $0.67 billion (after tax) ceiling test impairment charge at Gabon, Offshore West Africa and the impact of statutory tax rate changes on future income tax liabilities. Adjusted net earnings in 2010 were $2.6 billion compared to $2.7 billion in 2009.

- Cash flow from operations was approximately $6.3 billion, an increase of 4% from $6.1 billion in 2009. The increase in cash flow primarily resulted from the increase in higher crude oil and NGL sales volumes and netbacks partially offset by lower realized risk management gains, lower natural gas sales volumes and netbacks, the impact of the stronger Canadian dollar and higher cash taxes.

- Independent Qualified Reserves Evaluators evaluated and reviewed all of the Company's crude oil and natural gas reserves and the following are highlights based on Company gross reserves using forecast prices and costs as at December 31, 2010:

  - Company Gross proved crude oil and NGL reserves increased 8% to 3.80 billion barrels. Company Gross proved natural gas reserves increased 9% to 4.26 Tcf. Total proved BOE increased 8% to 4.51 billion barrels.

  - Company Gross proved plus probable crude oil and NGL reserves increased 9% to 5.94 billion barrels. Company Gross proved plus probable natural gas reserves increased 10% to 5.77 Tcf. Total proved plus probable BOE increased 9% to 6.90 billion barrels.

  - Company Gross proved reserve additions, including acquisitions, were 433 million barrels of crude oil and NGL and 814 billion cubic feet of natural gas, equating to 569 million barrels of oil equivalent. The total proved reserve replacement ratio on a BOE basis is 246%. Proved undeveloped reserves accounted for 30% of the Corporate total proved reserves.

  - Company Gross proved plus probable reserve additions, including acquisitions, were 624 million barrels of crude oil and NGL and 979 billion cubic feet of natural gas equating to 787 million barrels of oil equivalent. The total proved plus probable reserve replacement ratio on a BOE basis is 341%.

- Total net exploration and production reserve replacement expenditures totaled $4.8 billion in 2010, including acquisitions of approximately $1.9 billion. Horizon sustaining capital totaled $0.13 billion while project capital accumulated $0.41 billion (including capitalized interest, stock-based compensation and other). Total consolidated net capital expenditures for 2010 were $5.5 billion, an increase of $2.5 billion from 2009.

Fourth Quarter

- Total crude oil and NGLs production for Q4/10 was 438,835 bbl/d. Q4/10 crude oil production volumes increased 7% from Q3/10 of 411,585 bbl/d, and increased 20% from Q4/09 of 366,451 bbl/d. The increase in volumes in Q4/10 from Q3/10 and Q4/09 was primarily due to the Company's thermal and Horizon production volumes.

- Natural gas production volumes for the fourth quarter represented 32% of the Company's total production. Natural gas production for Q4/10 averaged 1,252 MMcf/d, comparable to 1,258 MMcf/d for Q3/10 and to 1,250 MMcf/d for Q4/09.

- The Company incurred a net loss in Q4/10 of $0.4 billion which included net unrealized after-tax expenses of $1.0 billion related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation and a ceiling test impairment charge at Gabon, Offshore West Africa. Excluding these items, adjusted net earnings from operations for Q4/10 was $0.6 billion, compared to adjusted net earnings of $0.6 billion in Q3/10 and $0.7 billion in Q4/09.

- Quarterly cash flow from operations was approximately $1.64 billion, a 6% increase from Q3/10 and a 4% decrease from Q4/09. The increase from Q3/10 primarily reflected higher crude oil and NGL sales volumes and netbacks, partially offset by realized risk management losses. The decrease from Q4/09 reflects the impact of realized risk management losses, lower natural gas pricing and higher cash taxes, partially offset by higher crude oil and NGL sales volumes.

Operational and Financial

- Canadian Natural drilled a record 654 net primary heavy crude oil wells in 2010. The Company targets to drill 791 net primary heavy crude oil wells in 2011 which will drive a target 11% production growth in 2011.

- Record quarterly thermal heavy crude oil production of approximately 104,000 bbl/d was achieved in Q4/10. Thermal production levels increased approximately 22% from Q3/10 and 81% from Q4/09. The Company targets 12% production growth in 2011 and continues to execute on its thermal heavy crude oil growth plan.

- The Company drilled 127 horizontal wells in 2010 at Pelican Lake with plans to drill an additional 93 horizontal wells in 2011. The Company continues to convert wells to polymer flood injectors and targets 18% production growth in 2011.

- During 2010, a 15 well drilling program was completed at Septimus, a Montney shale play in Northeast British Columbia and all wells have been tied in. Production volumes up to 60 MMcf/d have been achieved through the plant which had a design processing capacity of the 50 MMcf/d. Additionally, the liquids ratio associated with the Septimus play are slightly higher than expected at 30 bbl/MMcf or 1,800 bbl/d.

- International operations in the North Sea and Offshore West Africa provided cash flow from operations in 2010 of approximately $960 million against capital expenditures of $395 million, resulting in significant free cash flow to the Company. International operations provide exposure to Brent oil pricing and the Company targets additional significant free cash flow from the International operations in 2011.

- A continued focus on effective and efficient operations in 2010 resulted in lower production costs across the Company. In 2010, production costs on a Company average $/BOE basis decreased 6% compared to 2009.

- Company total capital expenditures are targeted between $6.2 billion and $6.6 billion in 2011. The capital expenditures reflect an allocation of approximately $2.6 billion to long-term growth initiatives that will add long-term production volumes in 2012 and beyond. As the Company generates strong cash flow, the production volumes impacted at Horizon due to the Coker fire have not impacted the Company’s capital expenditure plans for 2011.

- During 2010, the Company acquired approximately $1.9 billion of crude oil and natural gas properties in its core regions in Western Canada. These assets provide opportunities to lower operating costs, increase reserves and/or production and capture synergies with existing processing facilities and pipelines.

- The acquisition of leases adjacent to Canadian Natural's Kirby In Situ Oil Sands Project ("Kirby") provided the Company with gross proved plus probable reserves of 272 million barrels and the Company expects to gain significant operating synergies through these leases which will create the potential to drive exploitation opportunities.

- Construction of Kirby Phase 1 commenced soon after sanction in Q4/10. Kirby's first steam-in is targeted for 2013 and production is targeted to peak at 40,000 bbl/d. The overall cost of Kirby Phase 1 is targeted to be $1.25 billion.

- Horizon Synthetic Crude Oil ("SCO") production averaged 90,867 bbl/d in 2010, an increase of 81% from 2009. During 2010, average month over month production volumes demonstrated more consistency as preventative maintenance activities continued to be fine tuned. 2011 production volumes have been impacted as a result of a Coker fire that occurred on January 6, 2011. The Company targets to reach half plant production rates (55,000 bbl/d SCO) in Q2/11 and full plant production rates (110,000 bbl/d SCO) in Q3/11. Corporate guidance has been revised to reflect newly targeted volumes for 2011.

- The Company announced the re-profiling of Horizon's expansion in Q4/10. The expansion will be executed in a staged project execution plan. Project capital will be allocated to several different modules. Total expenditures on Horizon in 2011 will range between $800 million and $1,200 million dependent upon favorable market conditions and whether the business case meets the Company's investment criteria.

- In the first quarter of 2011, Canadian Natural announced that it has partnered with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of the bitumen refinery under the Alberta Royalty Framework's Bitumen Royalty In Kind ("BRIK") program. This project supports the Company's marketing strategy to ensure conversion capacity for the Company's products.

- Long term debt reductions of approximately $1.2 billion in 2010 further enhances the Company's already strong balance sheet, even after completing approximately $1.9 billion of acquisitions over the course of the year.

- During 2010, the Company repurchased two million common shares under the Company's Normal Course Issuer Bid.

- Canadian Natural's Board of Directors has resolved to increase its cash dividend on common shares for the eleventh year in a row. The 2011 quarterly dividend on common shares increased by 20% to C$0.09 from C$0.075 per common share, payable April 1, 2011. The dividend increase in 2011 follows a 43% increase in 2010.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate efficient operations, Canadian Natural focuses its activities in core regions where it can dominate the land base and infrastructure. Unproved property is critical to the Company's 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/medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal heavy crude oil, synthetic crude oil and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

OPERATIONS REVIEW

Activity by core region

	Net unproved properties as at Dec 31, 2010 (thousands of net acres)(1)	Drilling activity year ended Dec 31, 2010 (net wells)(2)
North America		
Northeast British Columbia	**2,389**	**34.9**
Northwest Alberta	**1,810**	**63.5**
Northern Plains	**6,497**	**879.4**
Southern Plains	**1,012**	**35.7**
Southeast Saskatchewan	**106**	**39.1**
Thermal In Situ Oil Sands(3)	**717**	**224.0**
	12,531	**1,276.6**
Oil Sands Mining and Upgrading(3)	**63**	**264.0**
North Sea	**128**	**1.8**
Offshore West Africa	**4,193**	**7.1**
	16,915	**1,549.5**

(1) Unproved property refers to a property or part of a property to which no reserves have been specifically attributed.

(2) Drilling activity includes stratigraphic test and service wells.

(3) Portions of the Oil Sands Mining and Upgrading lands relating to Birch Mountain have been reclassified to Thermal In Situ Oil Sands in Q4/10.

Drilling activity (number of wells)

	Year Ended Dec 31			
	2010		2009	
	Gross	**Net**	Gross	Net
Crude oil	**997**	**934**	686	644
Natural gas	**112**	**92**	141	109
Dry	**38**	**33**	49	46
Subtotal	**1,147**	**1,059**	876	799
Stratigraphic test / service wells	**492**	**491**	329	329
Total	**1,639**	**1,550**	1,205	1,128
Success rate (excluding stratigraphic test / service wells)		**97%**		94%

North America Exploration and Production

North America natural gas

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Natural gas production (MMcf/d)	**1,223**	1,234	1,218	**1,217**	1,287
Net wells targeting natural gas	**19**	19	28	**98**	117
Net successful wells drilled	**18**	19	28	**92**	109
Success rate	**95%**	100%	100%	**94%**	93%

- Q4/10 North America natural gas production volumes were up slightly from Q4/09 as a result of strong performance at Septimus and acquired natural gas volumes. Annual production for North America natural gas in 2010 was 1,217 MMcf/d, a decrease of 5% from 2009, as expected The reduction in 2010 volumes compared to 2009 was the result of a 16% reduction in the natural gas drilling program proactively implemented by the Company and partially offset by acquired natural gas volumes in 2010.

- Annual natural gas production costs in 2010 were $0.01 per Mcf lower than 2009 despite a production volume decrease of 5% from 2009 and the acquisition of higher production cost properties within core areas. This demonstrates the Company's focus on effective and efficient operations and the Company's ability to leverage its dominant owned infrastructure to create synergies to lower production costs.

- Canadian Natural targeted 19 net natural gas wells in Q4/10. In Northeast British Columbia, 1 net well was drilled, while in Northwest Alberta, 12 net wells were drilled. In the Northern Plains, 5 net wells were drilled, with 1 net well drilled in the Southern Plains.

- Planned drilling activity for 2011 includes 72 net natural gas wells compared to drilling activity for 2010 of 98 net natural gas wells. The reduction in drilling demonstrates the Company's ability to allocate capital to higher return projects.

North America crude oil and NGLs

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs production (bbl/d)	**286,698**	267,177	229,206	**270,562**	234,523
Net wells targeting crude oil	**323**	289	212	**953**	676
Net successful wells drilled	**316**	280	195	**926**	638
Success rate	**98%**	97%	92%	**97%**	94%

- Annual production for North America crude oil and NGLs in 2010 was 270,562 bbl/d, an increase of 15% from 2009 production. Q4/10 North America crude oil and NGLs production increased 7% and 25% from Q3/10 and Q4/09 levels respectively. The increase from the previous quarter reflects higher heavy crude oil volumes from each of our three growth areas, Primrose, Primary heavy crude oil and Pelican Lake.

- Annual crude oil and NGLs per unit production costs in 2010 decreased 17% from 2009 as a result of higher production volumes and the lower cost of natural gas used for fuel.

- Construction of Kirby Phase 1 commenced soon after sanction in Q4/10. Kirby's first steam-in is targeted for 2013 and production targeted to peak at 40,000 bbl/d. The overall cost of Kirby Phase 1 is targeted to be $1.25 billion. The Company expects to gain significant operating synergies within the Kirby development, which will create the potential to drive exploitation opportunities similar to those seen at Primrose over the last decade.

- Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as targeted in Q4/10. The Company drilled 127 horizontal wells in 2010 at Pelican Lake with plans to drill an additional 93 horizontal wells in 2011. Production averaged approximately 38,000 bbl/d for Q4/10, compared to approximately 38,000 bbl/d and 37,000 bbl/d for Q3/10 and Q4/09 respectively. Polymer flood production response is typically seen 18 to 24 months from injection of polymer flood and production increases from the Company's 2010 program are expected in late 2011/early 2012. By the end of 2010, 44% of the field has been converted to polymer flood. Canadian Natural targets to have close to 90% of the field under flood by 2015.

- A record drilling program in primary heavy crude oil was completed in 2010. 654 net primary heavy crude oil wells were drilled and the Company is targeting to drill 791 net primary heavy crude wells in 2011.

- During Q4/10, drilling activity targeted 323 net crude oil wells including 257 wells targeting heavy crude oil, 18 wells targeting Pelican Lake crude oil, 5 wells targeting thermal crude oil and 43 wells targeting light crude oil.

- Planned drilling activity for 2011 includes 1,186 net crude oil wells, excluding stratigraphic test and service wells compared with 953 in 2010. The Company targets 13% production growth in North America crude oil and NGLs in 2011.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil production (bbl/d)					
North Sea	**31,701**	27,045	34,408	**33,292**	37,761
Offshore West Africa	**27,706**	33,554	32,643	**30,264**	32,929
Natural gas production (MMcf/d)					
North Sea	**9**	8	12	**10**	10
Offshore West Africa	**20**	16	20	**16**	18
Net wells targeting crude oil	**2.4**	0.9	-	**8.0**	6.4
Net successful wells drilled	**2.4**	0.9	-	**8.0**	6.1
Success rate	**100%**	100%	-	**100%**	95%

North Sea

- North Sea production was 31,701 bbl/d during the quarter, and in line with Corporate guidance. Q4/10 production increased 17% from the previous quarter as Q3/10 was impacted by planned maintenance shut downs on all of the Company's North Sea production facilities. On an annual basis North Sea production was 33,292 bbl/d, a 12% decrease from 2009 reflecting natural declines and timing of scheduled maintenance shut downs.

Offshore West Africa

- In Q4/10, crude oil production at Offshore West Africa was 27,706 bbl/d, a decrease of 15% from Q4/09 as a result of natural declines and a decrease of 17% from Q3/10 reflecting compressor downtime at the Olowi Field ("Olowi"). Compressor repairs have been conducted in the fourth quarter of 2010 resulting in improved performance.

- Performance at Olowi continues to be below expectations, as was previously communicated by the Company, and as a result, the Company recognized an after tax ceiling test impairment on the Olowi property of $672 million at December 31, 2010. The Company has drilled 5 wells on Platform C, 6 wells on Platform B and 2 wells on Platform A and has elected to curtail further drilling at this time as the reserve expectations are not currently economic.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Synthetic crude oil production (bbl/d)	**92,730**	83,809	70,194	**90,867**	50,250

- Horizon SCO production averaged 90,867 bbl/d in 2010, an increase of 81% from 2009. During 2010, average month over month production volumes demonstrated more consistency as preventative maintenance activities continued to be fine tuned. 2011 production volumes will be negatively impacted as a result of a Coker fire that occurred on January 6, 2011. Corporate guidance has been revised to reflect newly targeted volumes for 2011.

- Cash production costs for the year averaged $36.36 per barrel of SCO (including approximately $3.78 per barrel of natural gas input costs), which is within the Company's previously issued guidance. The decrease in costs from 2009 costs of $39.89 per barrel of SCO was primarily due to the Company's focus on planned maintenance, reliability improvement and stabilized production at higher volumes. In Q4/10, cash production costs averaged $36.13 per barrel of SCO (including approximately $3.04 per barrel of natural gas input costs) compared to $41.21 per barrel of SCO in Q4/09.

- The Company announced the re-profiling of Horizon's expansion in Q4/10. The expansion will be executed in a staged project execution plan. Project capital will be allocated to several different modules. Total expenditures on Horizon in 2011 will range between $800 million and $1,200 million dependent upon favorability of market conditions and whether the business case meets the Company's investment criteria.

- The Company is continuing restoration of production from, and its investigation into, the fire at its coker unit at Horizon, which occurred on January 6, 2011. A preliminary assessment of the extent of damage and timelines to repair and rebuild are as follows:

  - The Coke Drums are serviceable.
  - Instrumentation to many areas of the plant remain intact.
  - Damage to the derrick structure over Coke Drums 1A and 1B will require the derrick to be replaced as anticipated. Damage to the derrick structure over Coke Drums 2A and 2B appears to be minimal at this point.
  - Limited damage to the rails that guide the cutting tools over Coke Drum 2B will require repair before Coke Drums 2A and 2B can be restarted.
  - Damage to the structural beams supporting both derrick structures over the Coke Drums will require limited repair or replacement.
  - The control station used for cutting of Coke Drums 1A and 1B will need to be replaced.
  - Pipe work above the Coke Drums will require inspection and testing (x-ray and or pressure testing) to determine if certain sections of pipework needs to be replaced.
  - Collateral freeze damage due to the unplanned shutdown and extreme cold weather has occurred after the fire and it has been determined to be more extensive than the preliminary assessment indicated. Some pumps and more importantly, the air coolers and furnace tubes associated with the Coke Drum operation will require extensive repair or replacement.
  - Material and equipment orders were initiated in January to replace components above Coke Drums 1A and 1B, as any excess material not needed for repair will be utilized in the future expansion which includes the installation of Coke Drums 3A and 3B.
  - Preliminary target time lines at this early stage indicate that the first set of Coke Drums 2A and 2B are targeted to resume production in Q2/11. Once the first set of Coke Drums is onstream production rates are targeted to be 55,000 bbl/d of SCO.
  - The second set of Coke Drums 1A and 1B are currently targeted to be on production in Q3/11.

- The Company has determined that the derrick and equipment above Coke Drum 2A and 2B are not on the critical path. Coker furnace tube replacement due to freezing after the fire is now on the critical path for Coke Drums 2A and 2B startup.

▪ Fire repair/rebuild costs, including associated damage, are currently estimated at approximately $300 million to $400 million at this time, reflecting a more detailed onsite review of damages. The Company will continue to provide updates as the repair progresses.

▪ The Company maintains an insurance program adequate to cover the cost of the repair/rebuild, as well as, business interruption insurance subject to a waiting period, to alleviate ongoing operating costs thereby somewhat mitigating financial impacts of the incident.

MARKETING

	Three Months Ended			Year Months Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs pricing					
WTI(1) benchmark price (US$/bbl)	**$ 85.18**	$ 76.21	$ 76.17	**$ 79.55**	$ 61.93
Western Canadian Select blend differential from WTI (%)	**21%**	20%	16%	**18%**	16%
SCO price (US$/bbl)	**$ 83.14**	$ 75.30	$ 75.07	**$ 78.56**	$ 61.51
Average realized pricing before risk management(2) (C$/bbl)	**$ 67.74**	$ 63.21	$ 68.00	**$ 65.81**	$ 57.68
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.39**	$ 3.53	$ 4.01	**$ 3.91**	$ 3.91
Average realized pricing before risk management (C$/Mcf)	**$ 3.56**	$ 3.75	$ 4.75	**$ 4.08**	$ 4.53

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

(2) Excludes SCO.

▪ In Q4/10, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 21%. Widening of heavy crude oil differentials in Q4/10 from the comparable period in 2009 largely resulted from pipeline disruptions in the United States that occurred during Q3/10.

▪ During Q4/10, the Company contributed approximately 180,000 bbl/d of its heavy crude oil streams to the WCS blend. Canadian Natural is the largest contributor accounting for 58% of the WCS blend.

REDWATER UPGRADING AND REFINING

▪ In Q1/11, Canadian Natural announced that it has partnered with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of the bitumen refinery. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the BRIK initiative. The project engineering is well advanced and work towards sanction level completion is ongoing.

FINANCIAL REVIEW

▪ As a result of the Company's continued focus on discipline and efficient and effective operations, the financial position of the Company is robust. Canadian Natural continually examines its liquidity position and targets a low risk approach to finance. The Company's commodity hedging program, its existing credit facilities and capital expenditure programs all support a flexible financial position:

- A large and diverse asset base spread over various commodity types - produced in excess of 630,000 BOE/d in 2010, with 95% of production located in G8 countries.

- Financial stability and liquidity - cash flow from operations of $6.3 billion in 2010 with available unused bank lines of $2.4 billion at December 31, 2010. The Company believes that its capital resources are sufficient to compensate for any short-term cashflow reductions arising from Horizon, and accordingly, the Company's targeted capital program currently remains unchanged for 2011.
- Flexibility in asset base and positive free cash flow produced from International and North America assets, and allows for a disciplined capital allocation program.

▪ A strong balance sheet with debt to book capitalization of 29% and debt to EBITDA of 1.1 times.

▪ Long term debt reductions of approximately $1.2 billion in 2010 further enhances the Company's already strong balance sheet, even after completing approximately $1.9 billion of acquisitions over the course of the year.

▪ During 2010, the Company repurchased two million common shares under the Company's Normal Course Issuer Bid.

▪ Canadian Natural's Board of Directors has resolved to increase its cash dividend on common shares for the eleventh year in a row. The 2011 quarterly dividend on common shares increased by 20% to C$0.09 from C$0.075 per common share, payable April 1, 2011. The dividend increase in 2011 follows a 43% increase in 2010.

OUTLOOK

The Company forecasts 2011 production levels before royalties to average between 1,177 and 1,246 MMcf/d of natural gas and between 385,000 and 427,000 bbl/d of crude oil and NGLs. Q1/11 production guidance before royalties is forecast to average between 1,249 and 1,273 MMcf/d of natural gas and between 348,000 and 365,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2010 the Company retained Independent Qualified Reserves Evaluators (”Evaluators”), Sproule Associates Limited (“Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves. Sproule evaluated the Company’s North America and International crude oil, NGL and natural gas reserves. GLJ evaluated the Company’s Horizon synthetic crude oil reserves. The Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”). In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result the 2010 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Reserves Committee of the Company’s Board of Directors has met with and carried out independent due diligence procedures with the Evaluators as to the Company’s reserves.

Corporate Total

- Company Gross proved crude oil and NGL reserves increased 8% to 3.80 billion barrels. Company Gross proved natural gas reserves increased 9% to 4.26 Tcf. Total proved BOE increased 8% to 4.51 billion barrels.

- Company Gross proved plus probable crude oil and NGL reserves increased 9% to 5.94 billion barrels. Company Gross proved plus probable natural gas reserves increased 10% to 5.77 Tcf. Total proved plus probable BOE increased 9% to 6.90 billion barrels.

- Company Gross proved reserve additions, including acquisitions, were 433 million barrels of crude oil and NGL and 814 billion cubic feet of natural gas. The total proved reserve replacement ratio on a BOE basis is 246%. Proved undeveloped reserves accounted for 30% of the Corporate total proved reserves.

- On a BOE basis, crude oil and NGLs account for 84% of Company gross proved reserves and 86% of Company gross proved plus probable reserves.

North America Exploration and Production

- North America company gross proved crude oil and NGL reserves increased 20% to 1.49 billion barrels. Company Gross proved natural gas reserves increased 10% to 4.09 Tcf. Total proved BOE increased 16% to 2.17 billion barrels.

- North America company gross proved plus probable crude oil and NGL reserves increased 22% to 2.50 billion barrels. Company Gross proved plus probable natural gas reserves increased 10% to 5.52 Tcf. Total proved plus probable BOE increased 19% to 3.42 billion barrels.

- North America company gross proved reserve additions, including acquisitions, were 345 million barrels of crude oil and NGL and 805 billion cubic feet of natural gas. The total proved reserve replacement ratio on a BOE basis is 277%. Proved undeveloped reserves accounted for 48% of the North America total proved reserves.

North America Oil Sands Mining and Upgrading

- Company gross proved synthetic crude oil reserves increased 3% to 1.93 billion barrels.

- Company gross proved plus probable synthetic crude oil reserves increased 2% to 2.89 billion barrels

International Exploration and Production

- North Sea company gross proved reserves decreased 4% to 265 million barrels of oil equivalent due to production and limited reserve adding activity in 2010. North Sea company gross proved plus probable reserves are 394 million barrels of oil equivalent.

- Offshore West Africa company gross proved reserves decreased 11% to 135 million barrels of oil equivalent due to production and technical revisions. Offshore West Africa company gross proved plus probable reserves are 200 million barrels of oil equivalent.

Summary of Company Gross Oil and Gas Reserves
As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	93	74	153	219	1,804	2,864	44	2,864
Developed Non-Producing	4	20	1	13	-	180	2	70
Undeveloped	13	66	85	687	128	1,048	17	1,171
Total Proved	110	160	239	919	1,932	4,092	63	4,105
Probable	40	57	109	783	956	1,430	20	2,203
Total Proved plus Probable	150	217	348	1,702	2,888	5,522	83	6,308
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	96					87		110
Developed Non-Producing	-					-		-
Undeveloped	24					5		25
Total Proved	120					92		135
Probable	57					46		65
Total Proved plus Probable	177					138		200
Total Company								
Proved								
Developed Producing	267	74	153	219	1,804	2,963	44	3,055
Developed Non-Producing	20	20	1	13	-	217	2	92
Undeveloped	195	66	85	687	128	1,082	17	1,358
Total Proved	482	160	239	919	1,932	4,262	63	4,505
Probable	221	57	109	783	956	1,505	20	2,397
Total Proved plus Probable	703	217	348	1,702	2,888	5,767	83	6,902

Reconciliation of Company Gross Reserves by Product
As of December 31, 2010
Forecast Prices and Costs

PROVED

North America	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	100	116	251	732	1,871	3,731	46	3,738
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1	(94)	(1)	(16)
Technical Revisions	6	30	(1)	64	93	144	6	222
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	**110**	**160**	**239**	**919**	**1,932**	**4,092**	**63**	**4,105**

North Sea	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	265	72	277
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(1)	10	1
Production	(12)	(4)	(13)
December 31, 2010	**252**	**78**	**265**

Offshore West Africa	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	136	99	152
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(5)	(1)	(5)
Production	(11)	(6)	(12)
December 31, 2010	**120**	**92**	**135**

Total Company	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	501	116	251	732	1,871	3,902	46	4,167
Discoveries	-	1	-	-	-	69	2	15
Extensions	1	20	2	47	-	217	5	111
Infill Drilling	3	25	-	-	-	21	1	33
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	12	2	-	109	-	446	7	204
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	1	(94)	(1)	(16)
Technical Revisions	-	30	(1)	64	93	153	6	218
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**482**	**160**	**239**	**919**	**1,932**	**4,262**	**63**	**4,505**

Reconciliation of Company Gross Reserves by Product
As of December 31, 2010
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	41	39	106	595	969	1,271	15	1,977
Discoveries	-	-	-	-	-	19	1	4
Extensions	-	8	2	61	-	98	2	89
Infill Drilling	3	10	1	-	-	14	-	16
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	1	-	163	-	110	1	187
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(3)	(26)	-	(7)
Technical Revisions	(8)	(1)	-	(36)	(10)	(55)	1	(63)
Production	-	-	-	-	-	-	-	-
December 31, 2010	**40**	**57**	**109**	**783**	**956**	**1,430**	**20**	**2,203**

North Sea

	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	127	24	131
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(3)	5	(2)
Production	-	-	-
December 31, 2010	**124**	**29**	**129**

Offshore West Africa

	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	63	45	71
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(6)	1	(6)
Production	-	-	-
December 31, 2010	**57**	**46**	**65**

Total Company

	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	231	39	106	595	969	1,340	15	2,179
Discoveries	-	-	-	-	-	19	1	4
Extensions	-	8	2	61	-	98	2	89
Infill Drilling	3	10	1	-	-	14	-	16
Improved Recovery	-	-	-	-	-	-	-	-
Acquisitions	4	1	-	163	-	110	1	187
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(3)	(26)	-	(7)
Technical Revisions	(17)	(1)	-	(36)	(10)	(49)	1	(71)
Production	-	-	-	-	-	-	-	-
December 31, 2010	**221**	**57**	**109**	**783**	**956**	**1,505**	**20**	**2,397**

Reconciliation of Company Gross Reserves by Product
As of December 31, 2010
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	141	155	357	1,327	2,840	5,002	61	5,715
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(2)	29	(1)	28	83	89	7	159
Production	(12)	(34)	(14)	(33)	(33)	(444)	(6)	(206)
December 31, 2010	**150**	**217**	**348**	**1,702**	**2,888**	**5,522**	**83**	**6,308**

North Sea

	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	392	96	408
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(4)	15	(1)
Production	(12)	(4)	(13)
December 31, 2010	**376**	**107**	**394**

Offshore West Africa

	Light and Medium Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	199	144	223
Discoveries	-	-	-
Extensions	-	-	-
Infill Drilling	-	-	-
Improved Recovery	-	-	-
Acquisitions	-	-	-
Dispositions	-	-	-
Economic Factors	-	-	-
Technical Revisions	(11)	-	(11)
Production	(11)	(6)	(12)
December 31, 2010	**177**	**138**	**200**

Total Company

	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2009	732	155	357	1,327	2,840	5,242	61	6,346
Discoveries	-	1	-	-	-	88	3	19
Extensions	1	28	4	108	-	315	7	200
Infill Drilling	6	35	1	-	-	35	1	49
Improved Recovery	-	-	1	-	-	2	3	4
Acquisitions	16	3	-	272	-	556	8	391
Dispositions	-	-	-	-	-	(1)	-	-
Economic Factors	-	-	-	-	(2)	(120)	(1)	(23)
Technical Revisions	(17)	29	(1)	28	83	104	7	147
Production	(35)	(34)	(14)	(33)	(33)	(454)	(6)	(231)
December 31, 2010	**703**	**217**	**348**	**1,702**	**2,888**	**5,767**	**83**	**6,902**

Summary of Company Net Oil and Gas Reserves
As of December 31, 2010
Forecast Prices and Costs

	Light and Medium Oil (MMbbl)	Primary Heavy Oil (MMbbl)	Pelican Lake Heavy Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	79	62	120	164	1,483	2,561	30	2,365
Developed Non-Producing	3	16	-	12	-	150	2	58
Undeveloped	11	57	62	535	114	927	13	946
Total Proved	93	135	182	711	1,597	3,638	45	3,369
Probable	33	47	72	600	764	1,232	14	1,735
Total Proved plus Probable	126	182	254	1,311	2,361	4,870	59	5,104
North Sea								
Proved								
Developed Producing	78					12		80
Developed Non-Producing	16					37		22
Undeveloped	158					29		163
Total Proved	252					78		265
Probable	124					29		129
Total Proved plus Probable	376					107		394
Offshore West Africa								
Proved								
Developed Producing	82					72		94
Developed Non-Producing	-					-		-
Undeveloped	19					4		20
Total Proved	101					76		114
Probable	48					37		54
Total Proved plus Probable	149					113		168
Total Company								
Proved								
Developed Producing	239	62	120	164	1,483	2,645	30	2,539
Developed Non-Producing	19	16	-	12	-	187	2	80
Undeveloped	188	57	62	535	114	960	13	1,129
Total Proved	446	135	182	711	1,597	3,792	45	3,748
Probable	205	47	72	600	764	1,298	14	1,918
Total Proved plus Probable	651	182	254	1,311	2,361	5,090	59	5,666

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.

(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.

(3) Forecast pricing assumptions utilized by the independent qualified reserves evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2011	2012	2013	2014	2015	Average annual increase thereafter
Crude oil and NGLs						
WTI at Cushing (US$/bbl)	$ 88.40	$ 89.14	$ 88.77	$ 88.88	$ 90.22	1.5%
Western Canada Select (C$/bbl)	$ 80.04	$ 80.71	$ 78.48	$ 76.70	$ 77.86	1.5%
Edmonton Par (C$/bbl)	$ 93.08	$ 93.85	$ 93.43	$ 93.54	$ 94.95	1.5%
Edmonton Pentanes+ (C$/bbl)	$ 95.32	$ 96.11	$ 95.68	$ 95.79	$ 97.24	1.5%
North Sea Brent (US$/bbl)	$ 87.15	$ 87.87	$ 87.48	$ 87.58	$ 88.89	1.5%
Natural gas						
Henry Hub Louisiana (US$/MMBtu)	$ 4.44	$ 5.01	$ 5.32	$ 6.80	$ 6.90	1.5%
AECO (C$/MMBtu)	$ 4.04	$ 4.66	$ 4.99	$ 6.58	$ 6.69	1.5%
BC Westcoast Station 2 (C$/MMBtu)	$ 3.98	$ 4.60	$ 4.93	$ 6.52	$ 6.63	1.5%

A foreign exchange rate of US$0.932/C$1.000 was used in the 2010 evaluation.

(4) Reserve additions are comprised of all categories of Company Gross reserve changes, exclusive of production.

(5) Reserve replacement ratio is the Company Gross reserve additions divided by the Company Gross production in the same period.

(6) Barrels of oil equivalent (BOE) is a conversion ratio of six thousand cubic feet (Mcf) of natural gas to one barrel (bbl) of crude oil.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes and costs, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands resumption of production and future expansion, Primrose, Pelican Lake, Olowi Field (Offshore Gabon), the Kirby Thermal Oil Sands Project, the Keystone Pipeline US Gulf Coast expansion, and the construction and operation of the North West upgrader also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, 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. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and natural gas liquids ("NGLs") not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. 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. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the year ended December 31, 2010 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2009.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. Common share data has been restated to reflect the two-for-one share split in May 2010. The Company's consolidated financial statements and this MD&A have been prepared in accordance with generally accepted accounting principles in Canada ("GAAP") in effect as at and for the periods ended December 31, 2010. Effective January 1, 2011, the Company will adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board. Unless otherwise stated, references to Canadian GAAP do not incorporate the impact of any changes to accounting standards that will be required due to changes required by IFRS. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by 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 GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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 method primarily applicable at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the year and three months ended December 31, 2010 in relation to the comparable periods in 2009 and the third quarter of 2010. The accompanying tables form an integral part of this MD&A. This MD&A is dated March 1, 2011. Additional information relating to the Company, including its amended Annual Information Form for the year ended December 31, 2009, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009(1)	**Dec 31 2010**	Dec 31 2009(1)
Revenue, before royalties	**$ 3,787**	$ 3,341	$ 3,319	**$ 14,322**	$ 11,078
Net earnings (loss)	**$ (416)**	$ 580	$ 455	**$ 1,697**	$ 1,580
Per common share – basic and diluted	**$ (0.38)**	$ 0.53	$ 0.42	**$ 1.56**	$ 1.46
Adjusted net earnings from operations (2)	**$ 618**	$ 606	$ 667	**$ 2,570**	$ 2,689
Per common share – basic and diluted	**$ 0.57**	$ 0.55	$ 0.61	**$ 2.36**	$ 2.48
Cash flow from operations (3)	**$ 1,641**	$ 1,545	$ 1,703	**$ 6,321**	$ 6,090
Per common share – basic and diluted	**$ 1.51**	$ 1.42	$ 1.57	**$ 5.81**	$ 5.62
Capital expenditures, net of dispositions	**$ 1,947**	$ 914	$ 694	**$ 5,506**	$ 2,997

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

(2) Adjusted net earnings from operations is a non-GAAP measure 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 reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. 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. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended			*Year Ended*	
($ millions)	***Dec 31 2010***	*Sep 30 2010*	*Dec 31 2009*	***Dec 31 2010***	*Dec 31 2009*
Net earnings (loss) as reported	***$ (416)***	*$ 580*	*$ 455*	***$ 1,697***	*$ 1,580*
Stock-based compensation expense, net of tax (a) (e)	***336***	*18*	*65*	***294***	*261*
Unrealized risk management loss (gain), net of tax (b)	***131***	*71*	*224*	***(16)***	*1,437*
Unrealized foreign exchange gain, net of tax (c)	***(105)***	*(63)*	*(77)*	***(160)***	*(570)*
Gabon, Offshore West Africa ceiling test impairment (d)	***672***	*–*	*–*	***672***	*–*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (e)	***–***	*–*	*–*	***83***	*(19)*
Adjusted net earnings from operations	***$ 618***	*$ 606*	*$ 667*	***$ 2,570***	*$ 2,689*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swaps, and are recognized in net earnings.

(d) Performance from the Olowi Field continues to be below expectations. As a result, the Company recognized a pre-tax ceiling test impairment charge of $726 million ($672 million after-tax) at December 31, 2010.

(e) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. During the first quarter of 2010, the Canadian Federal budget proposed changes to the taxation of stock options surrendered by employees for cash payments. As a result of the changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of future income tax deductions for the Company. The impact of this change was an $83 million charge to future income tax expense during the first quarter. Income tax rate changes in the first quarter of 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America.

Cash Flow from Operations

	Three Months Ended			Year Ended	
($ millions)	***Dec 31 2010***	*Sep 30 2010*	*Dec 31 2009*	***Dec 31 2010***	*Dec 31 2009*
Net earnings (loss)	***$ (416)***	*$ 580*	*$ 455*	***$ 1,697***	*$ 1,580*
Non-cash items:					
Depletion, depreciation and amortization	***1,578***	*851*	*836*	***4,036***	*2,819*
Asset retirement obligation accretion	***27***	*28*	*23*	***107***	*90*
Stock-based compensation expense	***336***	*18*	*87*	***294***	*355*
Unrealized risk management loss (gain)	***173***	*92*	*308*	***(25)***	*1,991*
Unrealized foreign exchange gain	***(120)***	*(75)*	*(88)*	***(180)***	*(661)*
Deferred petroleum revenue tax expense	***5***	*11*	*7*	***28***	*15*
Future income tax expense (recovery)	***58***	*40*	*75*	***364***	*(99)*
Cash flow from operations	***$ 1,641***	*$ 1,545*	*$ 1,703*	***$ 6,321***	*$ 6,090*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2010 were $1,697 million compared to $1,580 million for the year ended December 31, 2009. Net earnings for the year ended December 31, 2010 included net unrealized after-tax expenses of $873 million related to the effects of stock-based compensation, risk management activities, fluctuations in foreign exchange rates, the impact of a ceiling test impairment charge at Gabon, Offshore West Africa and the impact of statutory tax rate and other legislative changes on future income tax liabilities, compared to $1,109 million for the year ended December 31, 2009. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2010 were $2,570 million, compared to $2,689 million for the year ended December 31, 2009.

The decrease in adjusted net earnings from the year ended December 31, 2009 was primarily due to:

- lower realized risk management gains;
- higher depletion, depreciation and amortization expense;
- lower natural gas sales volumes and netbacks; and
- the impact of the stronger Canadian dollar, partially offset by
- the impact of higher crude oil and NGL sales volumes and netbacks.

The net loss for the fourth quarter of 2010 was $416 million compared to net earnings of $455 million for the fourth quarter of 2009 and $580 million for the prior quarter. The net loss for the fourth quarter of 2010 included net unrealized after-tax expenses of $1,034 million related to the effects of stock-based compensation, risk management activities, fluctuations in foreign exchange rates, and the impact of a ceiling test impairment charge at Gabon, Offshore West Africa compared to $212 million for the fourth quarter of 2009 and $26 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2010 were $618 million compared to $667 million for the fourth quarter of 2009 and $606 million for the prior quarter.

The decrease in adjusted net earnings for the fourth quarter of 2010, compared to the fourth quarter of 2009 was primarily due to the impact of realized risk management losses, lower natural gas pricing and the impact of the stronger Canadian dollar, partially offset by higher crude oil and NGL sales volumes.

The increase in adjusted net earnings for the fourth quarter of 2010, compared to the prior quarter, was primarily due to the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by realized risk management losses.

The impacts of stock-based compensation, unrealized risk management activities and changes in foreign exchange rates are expected to continue to contribute to quarterly volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the year ended December 31, 2010 was $6,321 million compared to $6,090 million for the year ended December 31, 2009. Cash flow from operations for the fourth quarter of 2010 was $1,641 million compared to $1,703 million for the fourth quarter of 2009 and $1,545 million for the prior quarter.

The increase in cash flow from operations for the year ended December 31, 2010 from the comparable period in 2009 was primarily due to:

- the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by
- lower realized risk management gains;
- lower natural gas sales volumes and netbacks;
- higher cash taxes; and
- the impact of the stronger Canadian dollar.

The decrease in cash flow from operations in the current quarter compared to the fourth quarter of 2009 was primarily due to:

- realized risk management losses;
- the impact of lower natural gas pricing; and
- higher cash taxes, partially offset by
- the impact of higher crude oil and NGL sales volumes.

The increase in cash flow from operations from the prior quarter was primarily due to the impact of higher crude oil and NGL sales volumes and netbacks, partially offset by realized risk management losses.

Total production before royalties for the year ended December 31, 2010 increased 10% to 632,191 BOE/d from 574,730 BOE/d for the year ended December 31, 2009. Total production before royalties for the fourth quarter of 2010 increased 13% to 647,441 BOE/d from 574,857 BOE/d for the fourth quarter of 2009 and increased 4% from 621,284 BOE/d for the prior quarter. Production for the fourth quarter of 2010 was within the Company's previously issued guidance.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Dec 31 2010**		Sep 30 2010		Jun 30 2010		Mar 31 2010(1)
Revenue, before royalties	**$**	**3,787**	$	3,341	$	3,614	$	3,580
Net earnings (loss)	**$**	**(416)**	$	580	$	667	$	866
Net earnings (loss) per common share								
– Basic and diluted	**$**	**(0.38)**	$	0.53	$	0.61	$	0.80

($ millions, except per common share amounts)		Dec 31 2009(1)		Sep 30 2009(1)		Jun 30 2009(1)		Mar 31 2009(1)
Revenue, before royalties	$	3,319	$	2,823	$	2,750	$	2,186
Net earnings	$	455	$	658	$	162	$	305
Net earnings per common share								
– Basic and diluted	$	0.42	$	0.61	$	0.15	$	0.28

(1) Per common share amounts have been restated to reflect a two-for-one common share split in May 2010.

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of fluctuating demand, inventory storage levels and geopolitical uncertainties on worldwide benchmark pricing, and the impact of the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement and ramp up of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates and the impact of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, production and cost optimizations in North America and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, proved reserves, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the impact of the commencement of operations at Horizon and the Olowi Field in Offshore Gabon and the impact of ceiling test impairments at the Olowi Field.
- **Stock-based compensation** – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Fluctuations in unrealized foreign exchange gains and losses are recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended						Year Ended			
		Dec 31 2010		Sep 30 2010		Dec 31 2009		**Dec 31 2010**		Dec 31 2009
WTI benchmark price (US$/bbl) (1)	**$**	**85.18**	$	76.21	$	76.17	**$**	**79.55**	$	61.93
Dated Brent benchmark price (US$/bbl)	**$**	**86.49**	$	76.85	$	74.54	**$**	**79.50**	$	61.61
WCS blend differential from WTI (US$/bbl)	**$**	**18.15**	$	15.60	$	12.08	**$**	**14.26**	$	9.64
WCS blend differential from WTI (%)		**21%**		20%		16%		**18%**		16%
SCO price (US$/bbl) (2)	**$**	**83.14**	$	75.30	$	75.07	**$**	**78.56**	$	61.51
Condensate benchmark price (US$/bbl)	**$**	**85.18**	$	74.52	$	74.46	**$**	**81.81**	$	60.60
NYMEX benchmark price (US$/MMBtu)	**$**	**3.81**	$	4.42	$	4.27	**$**	**4.42**	$	4.03
AECO benchmark price (C$/GJ)	**$**	**3.39**	$	3.53	$	4.01	**$**	**3.91**	$	3.91
US / Canadian dollar average exchange rate	**$**	**0.9874**	$	0.9624	$	0.9468	**$**	**0.9709**	$	0.8760

(1) West Texas Intermediate ("WTI")

(2) Synthetic Crude Oil ("SCO")

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$79.55 per bbl for the year ended December 31, 2010, an increase of 28% from US$61.93 per bbl for the year ended December 31, 2009. WTI averaged US$85.18 per bbl for the fourth quarter of 2010, an increase of 12% from US$76.17 per bbl for the fourth quarter of 2009, and from US$76.21 per bbl in the prior quarter. WTI pricing was reflective of the slow overall economic recovery in the United States and Europe, with offsetting strong Asian demand mitigating the decline. The relative weakness of the US dollar also contributed to higher WTI pricing.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which is more reflective of international markets and overall supply and demand. Brent averaged US$79.50 per bbl for the year ended December 31, 2010, an increase of 29% compared to US$61.61 per bbl for the year ended December 31, 2009. Brent averaged US$86.49 per bbl for the fourth quarter of 2010, an increase of 16% compared to US$74.54 per bbl for the fourth quarter of 2009, and an increase of 13% from US$76.85 per bbl for the prior quarter. Brent pricing was reflective of continued strong demand from Asian markets. The higher Brent pricing relative to WTI was due to logistical constraints and high inventory levels of crude at Cushing during portions of 2010.

The Western Canadian Select ("WCS") Heavy Differential averaged 18% for the year ended December 31, 2010 compared to 16% for the year ended December 31, 2009. The WCS Heavy Differential widened in the fourth quarter of 2010, averaging 21% compared to 16% for the fourth quarter of 2009 and 20% for the prior quarter, partially due to pipeline disruptions in the last half of 2010 that forced the temporary shutdown and apportionment of major oil pipelines to Midwest refineries in the United States.

The Company uses condensate as a blending diluent for heavy crude oil pipeline shipments. During the fourth quarter of 2010, condensate prices were comparable to WTI, compared to a discount in the prior quarter, reflecting normal seasonality.

The Company anticipates continued volatility in crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events, and the timing and extent of the continuing economic recovery. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.42 per MMBtu for the year ended December 31, 2010, an increase of 10% from US$4.03 per MMBtu for the year ended December 31, 2009. NYMEX natural gas prices averaged US$3.81 per MMBtu for the fourth quarter of 2010, a decrease of 11% from US$4.27 per MMBtu for the fourth quarter of 2009, and a decrease of 14% from US$4.42 per MMBtu for the prior quarter.

AECO natural gas prices averaged $3.91 per GJ for the years ended December 31, 2010 and 2009. AECO natural gas prices for the fourth quarter of 2010 decreased 15% to average $3.39 per GJ from $4.01 per GJ in the fourth quarter of 2009, and decreased 4% from $3.53 per GJ for the prior quarter.

Cool weather in the United States in the fourth quarter of 2010 positively impacted natural gas prices, drawing down the high inventory levels and partially offsetting strong incremental production from shale gas plays. Natural gas prices continue to be depressed due to strong US natural gas production limiting the upside to natural gas price recovery.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**286,698**	267,177	229,206	**270,562**	234,523
North America – Oil Sands Mining and Upgrading	**92,730**	83,809	70,194	**90,867**	50,250
North Sea	**31,701**	27,045	34,408	**33,292**	37,761
Offshore West Africa	**27,706**	33,554	32,643	**30,264**	32,929
	438,835	411,585	366,451	**424,985**	355,463
Natural gas (MMcf/d)					
North America	**1,223**	1,234	1,218	**1,217**	1,287
North Sea	**9**	8	12	**10**	10
Offshore West Africa	**20**	16	20	**16**	18
	1,252	1,258	1,250	**1,243**	1,315
Total barrels of oil equivalent (BOE/d)	**647,441**	621,284	574,857	**632,191**	574,730
Product mix					
Light/medium crude oil and NGLs	**17%**	18%	20%	**18%**	21%
Heavy Pelican Lake crude oil	**6%**	6%	7%	**6%**	6%
Heavy primary crude oil	**15%**	15%	15%	**15%**	15%
Bitumen (thermal heavy crude oil)	**16%**	14%	10%	**14%**	11%
Synthetic crude oil	**14%**	13%	12%	**14%**	9%
Natural gas	**32%**	34%	36%	**33%**	38%
Percentage of gross revenue (1) (excluding midstream revenue)					
Crude oil and NGLs	**88%**	86%	82%	**85%**	78%
Natural gas	**12%**	14%	18%	**15%**	22%

(1) Net of transportation and blending costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**223,034**	220,836	195,070	**219,736**	201,873
North America – Oil Sands Mining and Upgrading	**89,530**	81,077	67,806	**87,763**	48,833
North Sea	**31,644**	27,002	34,341	**33,227**	37,683
Offshore West Africa	**25,291**	30,724	30,296	**28,288**	29,922
	369,499	359,639	327,513	**369,014**	318,311
Natural gas (MMcf/d)					
North America	**1,206**	1,213	1,135	**1,168**	1,214
North Sea	**9**	8	12	**10**	10
Offshore West Africa	**18**	15	19	**15**	17
	1,233	1,236	1,166	**1,193**	1,241
Total barrels of oil equivalent (BOE/d)	**574,959**	565,595	521,894	**567,743**	525,103

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/medium crude oil and NGLs, heavy Pelican Lake crude oil, heavy primary crude oil, bitumen (thermal heavy crude oil), and SCO.

Total crude oil and NGLs production for the year ended December 31, 2010 increased 20% to 424,985 bbl/d from 355,463 bbl/d for the year ended December 31, 2009. The increase was primarily due to the higher volumes from the Company's thermal and Horizon operations.

Total crude oil and NGLs production for the fourth quarter of 2010 increased 20% to 438,835 bbl/d from 366,451 bbl/d for the fourth quarter of 2009, and increased 7% from 411,585 bbl/d for the prior quarter. The increase from the comparable period in 2009 was primarily related to the cyclic nature of the Company's thermal operations and increased Horizon production. The increase from the prior quarter was related to an unplanned outage at Horizon and planned turnaround activities in the North Sea that reduced production in the third quarter of 2010, and the impact of the cyclic nature of the Company's thermal production. Crude oil and NGLs production in the fourth quarter of 2010 was within the Company's previously issued guidance of 432,000 to 456,000 bbl/d.

Natural gas production for the year ended December 31, 2010 decreased 5% to 1,243 MMcf/d compared to 1,315 MMcf/d for the year ended December 31, 2009. Natural gas production for the fourth quarter of 2010 of 1,252 MMcf/d was comparable to the fourth quarter of 2009 and the prior quarter. The decrease in natural gas production from the year ended December 31, 2009 reflects the expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity, partially offset by new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during the year. Natural gas production in the fourth quarter of 2010 was within the Company's previously issued guidance of 1,248 to 1,273 MMcf/d.

For 2011, revised annual production guidance is targeted to average between 385,000 and 427,000 bbl/d of crude oil and NGLs and between 1,177 and 1,246 MMcf/d of natural gas. First quarter 2011 production guidance is targeted to average between 348,000 and 365,000 bbl/d of crude oil and NGLs and between 1,249 and 1,273 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2010 increased 15% to average 270,562 bbl/d from 234,523 bbl/d for the year ended December 31, 2009. For the fourth quarter of 2010, crude oil and NGLs production increased 25% to average 286,698 bbl/d, compared to 229,206 bbl/d for the fourth quarter of 2009, and increased 7% from 267,177 bbl/d for the prior quarter. Increases in crude oil and NGLs production from comparable periods were primarily due to the cyclic nature of the Company's thermal production and the results of the impact of a record heavy oil drilling program. Production of crude oil and NGLs was within the Company's previously issued guidance of 283,000 bbl/d to 293,000 bbl/d for the fourth quarter of 2010.

Natural gas production for the year ended December 31, 2010 decreased 5% to 1,217 MMcf/d from 1,287 MMcf/d for the year ended December 31, 2009. For the fourth quarter of 2010, natural gas production of 1,223 MMcf/d was comparable to the fourth quarter of 2009 and the prior quarter. The decrease in natural gas production for the year ended December 31, 2010 from the comparable period in 2009 reflected the expected production declines due to the allocation of capital to higher return crude oil projects, which resulted in a strategic reduction of natural gas drilling activity, partially offset by new production volumes from the Septimus facility in North East British Columbia and from natural gas producing properties acquired during the year. Production of natural gas was within the Company's previously issued guidance of 1,220 MMcf/d to 1,240 MMcf/d for the fourth quarter of 2010.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 90,867 bbl/d for the year ended December 31, 2010, an increase of 81% from 50,250 bbl/d for the year ended December 31, 2009. For the fourth quarter of 2010, production increased 32% to 92,730 bbl/d, compared to 70,194 bbl/d in the fourth quarter of 2009, and increased 11% from 83,809 bbl/d in the prior quarter. Increases in production of synthetic crude oil from comparable periods in 2009 reflected the Company's focus on reliability improvements and ramping up of production. The increase in the current quarter, compared to the prior quarter, reflected the impact of a plant-wide shutdown for unplanned maintenance in the prior quarter. Fourth quarter production for 2010 was within the Company's previously issued guidance of 90,000 bbl/d to 100,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2010 decreased 12% to 33,292 bbl/d from 37,761 bbl/d for the year ended December 31, 2009. Fourth quarter 2010 North Sea crude oil production decreased 8% to 31,701 bbl/d from 34,408 bbl/d for the fourth quarter of 2009 and increased 17% from 27,045 bbl/d in the prior quarter. Decreases in production volumes from the comparable periods in 2009 were due to the natural field declines and timing of scheduled maintenance shut downs. The increase in production volumes in the current quarter was a result of planned maintenance shut downs on all of the Company's North Sea production facilities in the prior quarter. Production in the fourth quarter of 2010 was within the Company's previously issued guidance of 30,000 bbl/d to 32,000 bbl/d.

Offshore West Africa

Offshore West Africa crude oil production decreased 8% to 30,264 bbl/d for the year ended December 31, 2010 from 32,929 bbl/d for the year ended December 31, 2009. Fourth quarter crude oil production decreased 15% to 27,706 bbl/d from 32,643 bbl/d for the fourth quarter of 2009, and decreased 17% from 33,554 bbl/d in the prior quarter. Decreases in production volumes from the comparable periods in 2009 were due to natural field declines. The decrease in production volumes from the prior quarter was due to compressor downtime at the Olowi Field. Repairs have been conducted in the fourth quarter of 2010 resulting in better compressor uptimes during the first quarter of 2011. Production in the fourth quarter of 2010 was below the Company's previously issued guidance of 29,000 bbl/d to 31,000 bbl/d.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offloading vessels, as follows:

(bbl)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009
North America – Exploration and Production	**761,351**	761,351	1,131,372
North America – Oil Sands Mining and Upgrading (SCO)	**1,172,200**	1,045,281	1,224,481
North Sea	**264,995**	793,582	713,112
Offshore West Africa	**404,197**	918,535	51,103
	2,602,743	3,518,749	3,120,068

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 67.74**	$ 63.21	$ 68.00	**$ 65.81**	$ 57.68
Royalties	**12.14**	9.05	7.96	**10.09**	6.73
Production expense	**13.59**	15.37	15.45	**14.16**	15.92
Netback	**$ 42.01**	$ 38.79	$ 44.59	**$ 41.56**	$ 35.03
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.56**	$ 3.75	$ 4.75	**$ 4.08**	$ 4.53
Royalties (3)	**0.07**	0.11	0.35	**0.20**	0.32
Production expense	**1.05**	1.05	1.03	**1.09**	1.08
Netback	**$ 2.44**	$ 2.59	$ 3.37	**$ 2.79**	$ 3.13
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 50.41**	$ 47.44	$ 51.95	**$ 49.90**	$ 44.87
Royalties	**7.83**	5.83	5.60	**6.72**	4.72
Production expense	**10.91**	11.89	11.72	**11.25**	11.98
Netback	**$ 31.67**	$ 29.72	$ 34.63	**$ 31.93**	$ 28.17

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

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 63.62**	$ 59.13	$ 65.12	**$ 62.28**	$ 54.70
North Sea	**$ 88.05**	$ 81.47	$ 78.89	**$ 82.49**	$ 68.84
Offshore West Africa	**$ 80.39**	$ 77.32	$ 72.88	**$ 78.93**	$ 65.27
Company average	**$ 67.74**	$ 63.21	$ 68.00	**$ 65.81**	$ 57.68
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.50**	$ 3.70	$ 4.75	**$ 4.05**	$ 4.51
North Sea	**$ 2.99**	$ 4.52	$ 4.94	**$ 3.83**	$ 4.66
Offshore West Africa	**$ 7.59**	$ 7.36	$ 5.04	**$ 6.63**	$ 6.11
Company average	**$ 3.56**	$ 3.75	$ 4.75	**$ 4.08**	$ 4.53
Company average ($/BOE) (1) (2)	**$ 50.41**	$ 47.44	$ 51.95	**$ 49.90**	$ 44.87

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

(2) Net of transportation and blending costs and excluding risk management activities.

North America

North America realized crude oil prices increased 14% to average $62.28 per bbl for the year ended December 31, 2010 from $54.70 per bbl for the year ended December 31, 2009. Realized crude oil prices averaged $63.62 per bbl for the fourth quarter of 2010, a decrease of 2% compared to $65.12 per bbl for the fourth quarter of 2009 and an increase of 8% compared to $59.13 per bbl for the prior quarter. The increase in prices from the year ended December 31, 2009 and the prior quarter was primarily a result of increased WTI benchmark pricing, partially offset by the impact of the widening Heavy Differential and the stronger Canadian dollar relative to the US dollar. The decrease in realized crude oil prices in the fourth quarter of 2010 from the comparable period in 2009 was due to the impact of a widening Heavy Differential and the stronger Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, and in the fourth quarter of 2010 contributed approximately 180,000 bbl/d of heavy crude oil blends to the WCS stream.

Subsequent to December 31, 2010, the Company announced that it had entered into a partnership agreement with North West Upgrading Inc. to move forward with detailed engineering regarding the construction and operation of a bitumen refinery near Redwater, Alberta. In addition, the partnership has entered into an agreement to process bitumen supplied by the Government of Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind initiative. Project development is dependent upon completion of this detailed engineering and final project sanction by the respective parties.

North America realized natural gas prices decreased 10% to average $4.05 per Mcf for the year ended December 31, 2010 from $4.51 per Mcf for the year ended December 31, 2009. Realized natural gas prices averaged $3.50 per Mcf for the fourth quarter of 2010, a decrease of 26% compared to $4.75 per Mcf for the fourth quarter of 2009 and a decrease of 5% from $3.70 per Mcf for the prior quarter. The decrease in natural gas prices from comparable periods in 2009 was primarily related to the impact of weak benchmark prices due to lower demand and high storage levels, the widening NYMEX and AECO differential, the impact of natural gas physical sales contracts in 2009 and the impact of a stronger Canadian dollar relative to the US dollar. The decrease in natural gas prices from the prior quarter was primarily related to lower benchmark prices due to high storage levels.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Quarterly Average)		**Dec 31 2010**		Sep 30 2010		Dec 31 2009
Wellhead Price (1) (2)						
Light/medium crude oil and NGLs ($/bbl)	**$**	**69.77**	$	62.40	$	67.30
Heavy Pelican Lake crude oil ($/bbl)	**$**	**61.73**	$	58.44	$	63.75
Heavy primary crude oil ($/bbl)	**$**	**62.62**	$	58.97	$	65.46
Bitumen (thermal heavy crude oil) ($/bbl)	**$**	**62.10**	$	57.60	$	63.62
Natural gas ($/Mcf)	**$**	**3.50**	$	3.70	$	4.75

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

(2) Net of transportation and blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 20% to average $82.49 per bbl for the year ended December 31, 2010 from $68.84 per bbl for the year ended December 31, 2009. Realized crude oil prices increased 12% to average $88.05 per bbl for the fourth quarter of 2010 from $78.89 per bbl for the fourth quarter of 2009, and increased 8% from $81.47 per bbl for the prior quarter. The increase in realized crude oil prices in the North Sea from the comparable periods in 2009 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 21% to average $78.93 per bbl for the year ended December 31, 2010 from $65.27 per bbl for the year ended December 31, 2009. Realized crude oil prices increased 10% to average $80.39 per bbl for the fourth quarter of 2010 from $72.88 per bbl for the fourth quarter of 2009, and increased 4% from $77.32 per bbl in the prior quarter. The increase in realized crude oil prices in Offshore West Africa from the comparable periods in 2009 was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 14.30**	$ 10.40	$ 9.88	**$ 11.85**	$ 7.93
North Sea	**$ 0.16**	$ 0.13	$ 0.15	**$ 0.16**	$ 0.14
Offshore West Africa	**$ 7.01**	$ 6.52	$ 5.24	**$ 5.54**	$ 5.79
Company average	**$ 12.14**	$ 9.05	$ 7.96	**$ 10.09**	$ 6.73
Natural gas ($/Mcf) (1)					
North America (2)	**$ 0.06**	$ 0.10	$ 0.35	**$ 0.20**	$ 0.32
Offshore West Africa	**$ 0.69**	$ 0.85	$ 0.27	**$ 0.53**	$ 0.53
Company average	**$ 0.07**	$ 0.11	$ 0.35	**$ 0.20**	$ 0.32
Company average ($/BOE) (1)	**$ 7.83**	$ 5.83	$ 5.60	**$ 6.72**	$ 4.72
Percentage of revenue (3)					
Crude oil and NGLs	**18%**	14%	12%	**15%**	12%
Natural gas (2)	**2%**	3%	7%	**5%**	7%
BOE	**16%**	12%	11%	**13%**	11%

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

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

(3) Net of transportation and blending costs and excluding risk management activities.

North America

North America royalties for the year ended December 31, 2010 compared to the year ended December 31, 2009 reflected stronger benchmark crude oil commodity prices and the impact of the changes under the Alberta Royalty Framework.

Crude oil and NGLs royalties averaged approximately 19% of revenues in 2010, compared to 14% in 2009. The increase in royalties was due to higher crude oil pricing and crude oil royalty adjustments. Crude oil and NGLs royalties averaged approximately 22% of revenues for the fourth quarter of 2010, compared to 15% for the fourth quarter in 2009 and 18% for the prior quarter. The increase in royalties from the comparable periods was due to crude oil royalty adjustments. Crude oil and NGLs royalties per bbl are anticipated to average 16% to 20% of gross revenue for 2011.

Natural gas royalties averaged approximately 5% of revenues in 2010, compared to 7% in 2009. Natural gas royalties averaged approximately 2% of revenues for the fourth quarter, compared to 7% for the fourth quarter of 2009 and 3% for the prior quarter. The decrease in natural gas royalty rates for the fourth quarter of 2010 compared to the fourth quarter of 2009 was primarily due to lower benchmark pricing. Natural gas royalties are anticipated to average 4% to 6% of gross revenue for 2011.

Offshore West Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 7% in 2010 compared to 9% in 2009. Royalty rates as a percentage of revenue averaged approximately 9% for the fourth quarter of 2010 compared to 7% for the fourth quarter of 2009 and 9% for the prior quarter. Offshore West Africa royalty rates are anticipated to increase in 2011 to average 13% to 15% of gross revenue for 2011, as a result of the expected payout of the Baobab Field.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 11.41**	$ 12.41	$ 13.44	**$ 12.14**	$ 14.63
North Sea	**$ 30.05**	$ 44.45	$ 27.03	**$ 29.73**	$ 26.98
Offshore West Africa	**$ 13.86**	$ 13.66	$ 15.26	**$ 14.64**	$ 12.83
Company average	**$ 13.59**	$ 15.37	$ 15.45	**$ 14.16**	$ 15.92
Natural gas ($/Mcf) [(1)]					
North America	**$ 1.02**	$ 1.04	$ 1.01	**$ 1.06**	$ 1.07
North Sea	**$ 2.70**	$ 2.42	$ 3.23	**$ 2.91**	$ 2.16
Offshore West Africa	**$ 2.00**	$ 1.69	$ 0.70	**$ 1.76**	$ 1.23
Company average	**$ 1.05**	$ 1.05	$ 1.03	**$ 1.09**	$ 1.08
Company average ($/BOE) [(1)]	**$ 10.91**	$ 11.89	$ 11.72	**$ 11.25**	$ 11.98

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2010 decreased 17% to $12.14 per bbl from $14.63 per bbl for the year ended December 31, 2009. Production expense for the fourth quarter of 2010 decreased 15% to $11.41 per bbl from $13.44 per bbl for the fourth quarter of 2009 and decreased 8% from $12.41 per bbl for the prior quarter. The decrease in production expense per barrel from the comparable periods in 2009 was a result of higher production volumes and the lower cost of natural gas used for fuel. The decrease in production expense per barrel from the prior quarter was due to the timing of thermal steam cycles. North America crude oil and NGLs production expense is anticipated to average $12.00 to $13.00 per bbl for 2011.

North America natural gas production expense for the year ended December 31, 2010 was comparable to production expense for the year ended December 31, 2009, as lower service costs offset the effects of lower production volumes. Production expense for the fourth quarter of 2010 was comparable to the fourth quarter of 2009 and decreased 2% from $1.04 per Mcf for the prior quarter. North America natural gas production expense is anticipated to average $1.10 to $1.20 per Mcf for 2011.

North Sea

North Sea crude oil production expense for the year ended December 31, 2010 increased 10% to $29.73 per bbl from $26.98 per bbl for the year ended December 31, 2009. Production expense for the fourth quarter of 2010 increased 11% to $30.05 per bbl from $27.03 per bbl for the fourth quarter of 2009 and decreased 32% from $44.45 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in 2009 due to lower volumes on relatively fixed costs. Production expense decreased on a per barrel basis from the prior quarter due to the timing of planned facility maintenance shutdowns in the prior quarter. Production expense is anticipated to average $38.00 to $42.00 per bbl for 2011.

Offshore West Africa

Offshore West Africa crude oil production expense increased 14% to $14.64 per bbl from $12.83 per bbl for the year ended December 31, 2009. Production expense for the fourth quarter of 2010 decreased 9% to $13.86 per bbl from $15.26 per bbl for the fourth quarter of 2009 and was comparable to the prior quarter. Production expense for the year ended December 31, 2010 increased on a per barrel basis from the comparable period in 2009 due to the timing of liftings for each field, including the impact of costs associated with the Olowi Field which has higher production expenses than the Espoir and Baobab Fields. Production expense for the fourth quarter of 2010 decreased from the comparable period in 2009 due to lower sales from the Olowi Field. Production expense is anticipated to average $18.00 to $21.00 per bbl for 2011.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Expense ($ millions)	**$ 1,480**	$ 763	$ 754	**$ 3,662**	$ 2,656
$/BOE (1)	**$ 28.41**	$ 15.22	$ 15.68	**$ 18.49**	$ 13.82

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

The increase in depletion, depreciation and amortization expense from the comparable periods in 2009 and the prior quarter was due to higher production in North America, an increase in the estimated future costs to develop the Company's proved undeveloped reserves in the North Sea and the impact of a ceiling test impairment related to Gabon, Offshore West Africa at December 31, 2010.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Expense ($ millions)	**$ 22**	$ 22	$ 17	**$ 85**	$ 69
$/BOE (1)	**$ 0.41**	$ 0.43	$ 0.36	**$ 0.43**	$ 0.36

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Accretion expense for the year ended December 31, 2010 increased from the comparable period due to higher asset retirement obligations recognized in the North Sea in 2009.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2010**	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
SCO sales price [2]	**$ 81.51**	$ 75.31	$ 76.33	**$ 77.89**	$ 70.83
Bitumen value for royalty purposes [3]	**$ 56.42**	$ 54.13	$ 58.90	**$ 56.14**	$ 56.57
Bitumen royalties [4]	**$ 2.77**	$ 2.57	$ 3.06	**$ 2.72**	$ 2.15

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

(2) Net of transportation.

(3) Calculated as the simple average of the monthly bitumen valuation methodology price.

(4) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices increased 10% to average $77.89 per bbl for the year ended December 31, 2010 from $70.83 per bbl for the year ended December 31, 2009. Realized SCO sales prices averaged $81.51 per bbl for the fourth quarter of 2010, an increase of 7% compared to $76.33 per bbl for the fourth quarter of 2009 and an increase of 8% compared to $75.31 per bbl for the prior quarter. The increase in SCO prices from the comparative periods was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar. There is an active market for SCO throughout North America.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Cash costs, excluding natural gas costs	**$ 278**	$ 243	$ 228	**$ 1,082**	$ 599
Natural gas costs	**26**	25	31	**126**	84
Total cash production costs	**$ 304**	$ 268	$ 259	**$ 1,208**	$ 683

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2010**	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Cash costs, excluding natural gas costs	**$ 33.09**	$ 31.20	$ 36.23	**$ 32.58**	$ 34.97
Natural gas costs	**3.04**	3.15	4.98	**3.78**	4.92
Total cash production costs	**$ 36.13**	$ 34.35	$ 41.21	**$ 36.36**	$ 39.89
Sales (bbl/d)	**91,350**	84,836	68,140	**91,010**	46,896

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

First sales from Horizon occurred in the second quarter of 2009.

Total cash production costs averaged $36.36 per bbl for the year ended December 31, 2010 compared to $39.89 per bbl for the year ended December 31, 2009. Total cash production costs averaged $36.13 per bbl in the fourth quarter of 2010 compared to $41.21 per bbl for the fourth quarter of 2009, and $34.35 per bbl in the prior quarter. The decrease in cash production costs from the comparative periods in 2009 was primarily due to the Company's focus on planned maintenance, reliability improvements and the stabilization of production volumes at levels approaching plant capacity. The increase in cash production costs from the prior quarter was primarily due to higher seasonal costs related to winter operating conditions, including higher diesel fuel costs, and the commencement of the annual winter stratigraphic well drilling program, partially offset by the effects of increased production volumes.

($ millions)	Three Months Ended **Dec 31 2010**	 Sep 30 2010	 Dec 31 2009	Year Ended **Dec 31 2010**	 Dec 31 2009
Depletion, depreciation and amortization	**$ 96**	$ 86	$ 83	**$ 366**	$ 187
Asset retirement obligation accretion	**5**	6	6	**22**	21
Total	**$ 101**	$ 92	$ 89	**$ 388**	$ 208

($/bbl) (1)	Three Months Ended **Dec 31 2010**	 Sep 30 2010	 Dec 31 2009	Year Ended **Dec 31 2010**	 Dec 31 2009
Depletion, depreciation and amortization	**$ 11.49**	$ 10.96	$ 13.28	**$ 11.02**	$ 10.95
Asset retirement obligation accretion	**0.66**	0.71	1.00	**0.67**	1.22
Total	**$ 12.15**	$ 11.67	$ 14.28	**$ 11.69**	$ 12.17

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

Depletion, depreciation and amortization increased from the comparable periods in 2009 and the prior quarter primarily due to higher sales volumes and the impact of certain assets depreciated on a straight-line basis.

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

MIDSTREAM

($ millions)	Three Months Ended **Dec 31 2010**	 Sep 30 2010	 Dec 31 2009	Year Ended **Dec 31 2010**	 Dec 31 2009
Revenue	**$ 20**	$ 19	$ 18	**$ 79**	$ 72
Production expense	**6**	4	5	**22**	19
Midstream cash flow	**14**	15	13	**57**	53
Depreciation	**2**	2	3	**8**	9
Segment earnings before taxes	**$ 12**	$ 13	$ 10	**$ 49**	$ 44

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended **Dec 31 2010**	 Sep 30 2010	 Dec 31 2009	Year Ended **Dec 31 2010**	 Dec 31 2009
Expense ($ millions)	**$ 53**	$ 43	$ 49	**$ 210**	$ 181
$/BOE (1)	**$ 0.88**	$ 0.73	$ 0.92	**$ 0.91**	$ 0.87

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

Administration expense for the year and three months ended December 31, 2010 increased from the comparative periods in 2009 and the prior quarter due to higher staffing and general corporate costs.

STOCK-BASED COMPENSATION EXPENSE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Expense	**$ 336**	$ 18	$ 87	**$ 294**	$ 355

The Company recorded a $294 million after-tax stock-based compensation expense for the year ended December 31, 2010 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the period, and a 17% increase in the Company's share price (Company's share price as at: December 31, 2010 - $44.35; September 30, 2010 – $35.59; December 31, 2009 – $38.00). For the year ended December 31, 2010, the Company capitalized $24 million in stock-based compensation to Oil Sands Mining and Upgrading (December 31, 2009 – $2 million). The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2010.

The Company's stock option plan provides current employees with the right to receive common shares or a direct cash payment in exchange for options surrendered. As a result of enacted changes to Canadian income tax legislation related to the cash surrender of options, the Company anticipates that Canadian based employees will now choose to exercise their options to receive newly issued common shares rather than surrender their options for cash payment.

For the year ended December 31, 2010, the Company paid $45 million for stock options surrendered for cash settlement (December 31, 2009 – $94 million).

INTEREST EXPENSE

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Expense, gross	**$ 129**	$ 116	$ 119	**$ 477**	$ 516
Less: capitalized interest, Oil Sands Mining and Upgrading	**9**	7	8	**28**	106
Expense, net	**$ 120**	$ 109	$ 111	**$ 449**	$ 410
$/BOE (1)	**$ 1.98**	$ 1.89	$ 2.06	**$ 1.94**	$ 1.96
Average effective interest rate	**5.7%**	4.9%	4.5%	**5.0%**	4.3%

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

Gross interest expense for the year ended December 31, 2010 decreased from 2009 as lower overall debt levels and the impact of a stronger Canadian dollar on US dollar denominated debt partially offset the impact of higher variable interest rates. Gross interest expense for the fourth quarter of 2010 increased from the comparable period in 2009 and the prior quarter as higher variable interest rates partially offset the impact of a stronger Canadian dollar on US dollar denominated debt.

The Company's average effective interest rate increased from the comparable periods in 2009 and the prior quarter primarily due to an increased weighting of fixed versus floating rate debt and higher variable interest rates.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Dec 31 2010**	Sep 30 2010	Dec 31 2009	Year Ended **Dec 31 2010**	Dec 31 2009
Crude oil and NGLs financial instruments	**$ 47**	$ 5	$ (148)	**$ 84**	$ (1,330)
Natural gas financial instruments	**(53)**	(85)	–	**(234)**	(33)
Foreign currency contracts and interest rate swaps	**32**	10	26	**54**	110
Realized loss (gain)	**$ 26**	$ (70)	$ (122)	**$ (96)**	$ (1,253)
Crude oil and NGLs financial instruments	**$ 108**	$ 8	$ 328	**$ (108)**	$ 2,039
Natural gas financial instruments	**51**	56	(17)	**71**	(58)
Foreign currency contracts and interest rate swaps	**14**	28	(3)	**12**	10
Unrealized loss (gain)	**$ 173**	$ 92	$ 308	**$ (25)**	$ 1,991
Net loss (gain)	**$ 199**	$ 22	$ 186	**$ (121)**	$ 738

Complete details related to outstanding derivative financial instruments at December 31, 2010 are disclosed in note 11 to the Company's unaudited interim consolidated financial statements. For additional information on the Company's risk management activities, refer to the audited consolidated financial statements and the MD&A for the year ended December 31, 2009.

The Company recorded a net unrealized gain of $25 million ($16 million after-tax) on its risk management activities for the year ended December 31, 2010, including a $173 million ($131 million after-tax) net unrealized loss for the fourth quarter of 2010 (September 30, 2010 – unrealized loss of $92 million, $71 million after-tax; December 31 2009 – unrealized loss of $308 million, $224 million after-tax), primarily due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Dec 31 2010**	Sep 30 2010	Dec 31 2009	Year Ended **Dec 31 2010**	Dec 31 2009
Net realized loss (gain)	**$ 6**	$ 11	$ 4	**$ (2)**	$ 30
Net unrealized gain (1)	**(120)**	(75)	(88)	**(180)**	(661)
Net gain	**$ (114)**	$ (64)	$ (84)	**$ (182)**	$ (631)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net unrealized foreign exchange gain for the year ended December 31, 2010 was primarily due to the strengthening of the Canadian dollar with respect to US dollar debt, together with the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. The net unrealized gain for the respective periods also included the impact of cross currency swaps (three months ended December 31, 2010 – unrealized loss of $71 million, September 30, 2010 – unrealized loss of $62 million, December 31, 2009 – unrealized loss of $48 million; year ended December 31, 2010 – unrealized loss of $101 million, December 31, 2009 – unrealized loss of $338 million). The net realized foreign exchange gain for the year ended December 31, 2010 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the fourth quarter at US$1.0054 (September 30, 2010 – US$0.9711; December 31, 2009 – US$0.9555).

TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2010	Sep 30 2010	Dec 31 2009	Year Ended Dec 31 2010	Dec 31 2009
Current	**$ 20**	$ 10	$ 25	**$ 91**	$ 91
Deferred	**5**	11	7	**28**	15
Taxes other than income tax	**$ 25**	$ 21	$ 32	**$ 119**	$ 106
North America [(1)]	**$ 49**	$ 115	$ 11	**$ 432**	$ 28
North Sea	**84**	23	60	**203**	278
Offshore West Africa	**23**	25	23	**63**	82
Current income tax	**156**	163	94	**698**	388
Future income tax expense (recovery)	**58**	40	75	**364**	(99)
	214	203	169	**1,062**	289
Income tax rate and other legislative changes [(2)]	**–**	–	–	**(83)**	19
	$ 214	$ 203	$ 169	**$ 979**	$ 308
Effective income tax rate on adjusted net earnings from operations	**32.3%**	25.9%	28.4%	**28.1%**	24.3%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Future income tax expense in the first quarter of 2010 included a charge of $83 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash. Income tax rate changes in the first quarter of 2009 include the effect of a recovery of $19 million due to enacted British Columbia corporate income tax rate reductions.

Taxes other than income tax primarily includes current and deferred Petroleum Revenue Tax (“PRT”), which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the exploration and production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2011, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $350 million to $450 million in Canada and $280 million to $320 million in the North Sea and Offshore West Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2010	Sep 30 2010	Dec 31 2009	Year Ended Dec 31 2010	Dec 31 2009
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 868**	$ 51	$ 11	**$ 1,904**	$ 6
Land acquisition and retention	**39**	27	28	**141**	77
Seismic evaluations	**19**	29	13	**100**	73
Well drilling, completion and equipping	**444**	365	291	**1,500**	1,244
Production and related facilities	**311**	253	222	**1,122**	977
Total net reserve replacement expenditures	**1,681**	725	565	**4,767**	2,377
Oil Sands Mining and Upgrading:					
Horizon Phase 1 construction costs	**–**	–	–	**–**	69
Horizon Phase 1 commissioning and other costs	**–**	–	–	**–**	202
Horizon Phases 2/3 construction costs	**100**	92	42	**319**	104
Capitalized interest, stock-based compensation and other	**30**	10	12	**88**	98
Sustaining capital	**48**	35	53	**128**	80
Total Oil Sands Mining and Upgrading [2]	**178**	137	107	**535**	553
Midstream	**3**	3	1	**7**	6
Abandonments [3]	**80**	45	17	**179**	48
Head office	**5**	4	4	**18**	13
Total net capital expenditures	**$ 1,947**	$ 914	$ 694	**$ 5,506**	$ 2,997
By segment					
North America	**$ 1,600**	$ 610	$ 436	**$ 4,369**	$ 1,663
North Sea	**38**	59	48	**149**	168
Offshore West Africa	**42**	55	80	**246**	544
Other	**1**	1	1	**3**	2
Oil Sands Mining and Upgrading	**178**	137	107	**535**	553
Midstream	**3**	3	1	**7**	6
Abandonments [3]	**80**	45	17	**179**	48
Head office	**5**	4	4	**18**	13
Total	**$ 1,947**	$ 914	$ 694	**$ 5,506**	$ 2,997

(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

(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 among various products. In order to facilitate efficient operations, the Company concentrates 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, 2010 were $5,506 million compared to $2,997 million for the year ended December 31, 2009. Net capital expenditures for the fourth quarter of 2010 were $1,947 million compared to $694 million for the fourth quarter of 2009 and $914 million in the prior quarter. The increase in capital expenditures from the comparable periods in 2009 was primarily due to the purchase of crude oil and natural gas producing properties and undeveloped land in the Company's core regions in Western Canada, and the increase in the Company's abandonment program. The increase in capital expenditures in the current quarter compared to the prior quarter was due to increased property acquisitions and drilling activities.

Drilling Activity (number of wells)

	Three Months Ended			Year Ended	
	Dec 31 2010	Sep 30 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Net successful natural gas wells	**18**	19	28	**92**	109
Net successful crude oil wells	**318**	281	195	**934**	644
Dry wells	**8**	9	17	**33**	46
Stratigraphic test / service wells	**171**	14	80	**491**	329
Total	**515**	323	320	**1,550**	1,128
Success rate (excluding stratigraphic test / service wells)	**98%**	97%	93%	**97%**	94%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 83% of the total capital expenditures for the year ended December 31, 2010 compared to approximately 58% for the year ended December 31, 2009.

During the fourth quarter of 2010, the Company targeted 19 net natural gas wells, including 1 well in Northeast British Columbia, 12 wells in Northwest Alberta, 5 wells in the Northern Plains region and 1 well in the Southern Plains region. The Company also targeted 323 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 257 heavy crude oil wells, 18 Pelican Lake crude oil wells, 5 thermal crude oil wells and 5 light crude oil wells were drilled. Another 38 wells targeting light crude oil were drilled outside the Northern Plains region.

As part of the phased expansion of its In Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the fourth quarter of 2010 averaged approximately 104,000 bbl/d, compared to approximately 57,000 bbl/d for the fourth quarter of 2009 and approximately 85,000 bbl/d for the prior quarter. The Primrose East expansion was completed and first steaming commenced in September 2008, with first production achieved in the first quarter of 2009. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. The Company received approval from regulators to commence steaming on the next cycle in the third quarter of 2010.

The next planned phase of the Company's In Situ Oil Sands Assets expansion is the Kirby Project. Currently the Company is proceeding with the detailed engineering and design work. During the third quarter of 2010, the Company received final regulatory approval for Phase 1 of the Project. During the fourth quarter, the Company's Board of Directors sanctioned Kirby Phase 1. Construction commenced in the fourth quarter of 2010, with first steam targeted in 2013.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout the fourth quarter of 2010. Drilling included 16 horizontal wells in the fourth quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 38,000 bbl/d for the fourth quarter of 2010, and was comparable to the fourth quarter of 2009 and the prior quarter.

For the first quarter of 2011, the Company's overall planned drilling activity in North America is expected to be comprised of 30 net natural gas wells and 270 net crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

Phase 2/3 spending during the fourth quarter continued to be focused on construction of the third Ore Preparation Plant, additional product tankage, the butane treatment unit, the sulphur recovery unit and hydro-transport.

On January 6, 2011, a fire occurred at the Company's primary upgrading coking plant. The fire was confined to one of the coke drums. Production capacity at Horizon has been suspended during the investigation and repair/rebuild to plant equipment damaged by the fire.

A preliminary assessment of the extent of damage and timelines to repair/rebuild indicate that the coke drums are serviceable. The procurement process for all necessary replacement components and parts for the damage caused by the fire has been initiated. Based on preliminary estimates, the first set of coke drums is targeted to resume production in the second quarter of 2011 with production rates of approximately 55,000 bbl/d. The second set of coke drums is currently targeted to be on production in the third quarter of 2011.

The Company believes that it has adequate insurance coverage to mitigate all significant property damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

North Sea

In the fourth quarter of 2010, the Company continued drilling on the Ninian South Platform, with 0.9 net crude wells drilled in the quarter. The Company plans to continue drilling at Ninian during 2011 and commence drilling at Murchison in the second quarter of 2011.

Offshore West Africa

At Espoir, incremental production volumes attributable to the facilities upgrades were delivered during the fourth quarter. Drilling continued at the Olowi Field with 1.5 net crude oil wells completed during the quarter. The Company achieved first crude oil production at Platform A in the fourth quarter of 2010.

Performance from the Olowi Field continues to be below expectations and, as a result, the Company recognized a pre-tax ceiling test impairment of $726 million ($672 million after-tax) at December 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2010**	Sep 30 2010	Dec 31 2009
Working capital (deficit) [(1)]	**$ (984)**	$ (515)	$ (514)
Long-term debt [(2)]	**$ 8,499**	$ 8,490	$ 9,658
Share capital	**$ 3,147**	$ 3,015	$ 2,834
Retained earnings	**18,005**	18,502	16,696
Accumulated other comprehensive loss	**(167)**	(97)	(104)
Shareholders' equity	**$ 20,985**	$ 21,420	$ 19,426
Debt to book capitalization [(2) (3)]	**29%**	28%	33%
Debt to market capitalization [(2) (4)]	**15%**	18%	19%
After tax return on average common shareholders' equity [(5)]	**8%**	13%	8%
After tax return on average capital employed [(2) (6)]	**7%**	10%	6%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

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

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

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

(6) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period.

At December 31, 2010, the Company's capital resources consist primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2009 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its on-going hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

The Company believes that its capital resources are sufficient to compensate for any short term cash flow reduction arising from Horizon, and accordingly, the Company's targeted capital program currently remains unchanged for 2011. At December 31, 2010, the Company had $2,444 million of available credit under its bank credit facilities. During the fourth quarter of 2010, the Company repaid $400 million of the medium term notes bearing interest at 5.50%.

Long-term debt was $8,499 million at December 31, 2010, resulting in a debt to book capitalization ratio of 29% (September 30, 2010 – 28%; December 31, 2009 – 33%). This ratio is below the 35% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occur. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil production for 2011 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2010 are discussed in note 4 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at December 31, 2010, in accordance with the policy, approximately 11% of budgeted crude oil volumes were hedged using collars for 2011.

Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2010 are discussed in note 11 to the Company's unaudited interim consolidated financial statements.

Share capital

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010, with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

As at December 31, 2010, there were 1,090,848,000 common shares outstanding and 66,844,000 stock options outstanding. As at March 1, 2011, the Company had 1,093,711,000 common shares outstanding and 63,029,000 stock options outstanding.

On March 1, 2011, the Company's Board of Directors approved an increase in the annual dividend to be paid by the Company to $0.36 per common share for 2011. The increase represents a 20% increase from 2010, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at March 1, 2011, 2,000,000 common shares had been purchased for cancellation at an average price of $33.77 per common share, for a total cost of $68 million.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at December 31, 2010, no entities were consolidated under the Canadian Institute of Chartered Accountants ("CICA") Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2010:

($ millions)	2011	2012	2013	2014	2015	Thereafter
Product transportation and pipeline	$ 228	$ 199	$ 172	$ 164	$ 152	$ 932
Offshore equipment operating leases	$ 141	$ 98	$ 97	$ 97	$ 81	$ 168
Offshore drilling	$ 7	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 18	$ 17	$ 19	$ 28	$ 27	$ 7,123
Long-term debt (2)	$ 398	$ 348	$ 798	$ 348	$ 400	$ 4,774
Interest expense (3)	$ 438	$ 400	$ 353	$ 333	$ 307	$ 4,236
Office leases	$ 27	$ 27	$ 28	$ 28	$ 32	$ 339
Other	$ 102	$ 66	$ 19	$ 16	$ 24	$ 10

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the estimated minimum expenditures required to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2010.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising from the Company's normal operations. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

CRITICAL ACCOUNTING ESTIMATES AND CHANGE IN ACCOUNTING POLICIES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP 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, 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project was broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has substantially completed its IFRS conversion project. Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. A summary of the significant differences identified is included below. As certain IFRS standards may change during 2011, the Company may be required to recognize additional new and /or amended accounting standards in the preparation of its December 31, 2011 consolidated financial statements prepared in accordance with IFRS.

The Company has identified, developed and tested systems and accounting and reporting processes and changes required to capture data required for IFRS accounting and reporting, including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are complete and implemented.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company followed the full cost method of accounting for its exploration and production properties and equipment as prescribed by Accounting Guideline 16 ("AcG16"). Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of the 2009 annual MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.
- Exploration and evaluation costs are initially capitalized as exploration and evaluation assets. In areas where the Company has existing operations, costs associated with reserves that are found to be technically feasible and commercially viable will be transferred to PP&E. If technically feasible and commercially viable reserves are not established in an area and if no further activity is planned in that area, the costs are expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.
- PP&E for producing properties is depleted at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.
- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is not required.
- Impairment of PP&E is tested at a cash generating unit level (the lowest level at which cash inflows can be separately identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company has adopted this transition exemption. After initial adoption, future impairment charges may be reversed.

Asset Retirement Obligations

Canadian GAAP accounting requirements for asset retirement obligations ("ARO") are discussed in the "Critical Accounting Estimates" section of the 2009 annual MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using the current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the increase in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the increase is adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes model. The Company has utilized the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated. On transition to IFRS, the increase in stock-based compensation liability must be recorded in retained earnings.

Petroleum Revenue Tax

Under Canadian GAAP, the liability for the UK PRT is estimated using proved plus probable reserves and future prices and costs, and apportioned to accounting periods over the life of the field on the basis of total estimated future operating income. Under IFRS, the PRT liability is estimated using the balance sheet method in accordance with IAS 12 Income Taxes, where the liability is based on temporary differences in balance sheet assets and liabilities versus their tax basis. On transition to IFRS, the increase in PRT liability must be recorded in retained earnings.

Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas. On transition to IFRS, the decrease in the net future income tax liability must be recorded in retained earnings.

Other IFRS 1 Exemptions

The Company has adopted the following IFRS 1 transition exemptions:

- The Company has elected to reset the foreign currency translation adjustment to $nil by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.

- The Company has adopted the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

IFRS Transitional Impacts

Giving effect to the above-noted transitional impacts, the Company estimates that on adoption of IFRS, total Shareholders' Equity as at January 1, 2010 decreased by less than 4% compared to the balance previously determined under Canadian GAAP, resulting in a marginal increase in the Company's reported debt to book capitalization to 34% from 33%. After the adoption of IFRS, the Company expects that 2010 net earnings decreased by an amount estimated to be between $100 million to $200 million, primarily due to higher depletion, depreciation and amortization, offset by lower UK PRT expense. Further, on adoption of IFRS, the Company does not anticipate any significant differences in cash flow from operations as would have been previously reported. Readers are cautioned that these estimates are subject to change, should underlying IFRS standards and/or the interpretations thereof be revised, prior to the final release of the Company's December 31, 2011 annual consolidated financial statements.

SENSITIVITY ANALYSIS

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 sales volumes during the fourth quarter of 2010, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being 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 [(1)]				
Excluding financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Including financial derivatives	$ 128	$ 0.12	$ 99	$ 0.09
Natural gas – AECO C$0.10/Mcf [(1)]				
Excluding financial derivatives	$ 34	$ 0.03	$ 25	$ 0.02
Including financial derivatives	$ 38	$ 0.04	$ 29	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 175	$ 0.16	$ 104	$ 0.10
Natural gas – 10 MMcf/d	$ 9	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 101 – 103	$ 0.09	$ 40 – 41	$ 0.04
Interest rate change – 1%	$ 9	$ 0.01	$ 9	$ 0.01

(1) For details of outstanding financial instruments in place, refer to note 11 of the Company's unaudited interim consolidated financial statements.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	**Dec 31 2010**	Dec 31 2009
ASSETS		
Current assets		
Cash and cash equivalents	**$ 22**	$ 13
Accounts receivable	**1,481**	1,148
Inventory, prepaids and other	**610**	584
Future income tax	**59**	146
	2,172	1,891
Property, plant and equipment (note 13)	**40,472**	39,115
Other long-term assets (note 3)	**25**	18
	$ 42,669	$ 41,024
LIABILITIES		
Current liabilities		
Accounts payable	**$ 274**	$ 240
Accrued liabilities	**2,163**	1,522
Current portion of other long-term liabilities (note 5)	**719**	643
	3,156	2,405
Long-term debt (note 4)	**8,499**	9,658
Other long-term liabilities (note 5)	**2,130**	1,848
Future income tax	**7,899**	7,687
	21,684	21,598
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**3,147**	2,834
Retained earnings	**18,005**	16,696
Accumulated other comprehensive loss (note 8)	**(167)**	(104)
	20,985	19,426
	$ 42,669	$ 41,024

Commitments (note 12)

Consolidated Statements of Earnings (Loss)

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Dec 31 2010	Three Months Ended Dec 31 2009	Year Ended Dec 31 2010	Year Ended Dec 31 2009
Revenue	**$ 3,787**	$ 3,319	**$ 14,322**	$ 11,078
Less: royalties	**(431)**	(285)	**(1,421)**	(936)
Revenue, net of royalties	**3,356**	3,034	**12,901**	10,142
Expenses				
Production	**874**	819	**3,447**	2,987
Transportation and blending	**460**	351	**1,783**	1,218
Depletion, depreciation and amortization (note 13)	**1,578**	836	**4,036**	2,819
Asset retirement obligation accretion (note 5)	**27**	23	**107**	90
Administration	**53**	49	**210**	181
Stock-based compensation expense (note 5)	**336**	87	**294**	355
Interest, net	**120**	111	**449**	410
Risk management activities (note 11)	**199**	186	**(121)**	738
Foreign exchange gain	**(114)**	(84)	**(182)**	(631)
	3,533	2,378	**10,023**	8,167
Earnings (loss) before taxes	**(177)**	656	**2,878**	1,975
Taxes other than income tax	**25**	32	**119**	106
Current income tax expense (note 6)	**156**	94	**698**	388
Future income tax expense (recovery) (note 6)	**58**	75	**364**	(99)
Net earnings (loss)	**$ (416)**	$ 455	**$ 1,697**	$ 1,580
Net earnings (loss) per common share (note 10)				
Basic and diluted	**$ (0.38)**	$ 0.42	**$ 1.56**	$ 1.46

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Year Ended Dec 31 2010	Dec 31 2009
Share capital (note 7)		
Balance – beginning of year	**$ 2,834**	$ 2,768
Issued upon exercise of stock options	**170**	24
Previously recognized liability on stock options exercised for common shares	**149**	42
Purchase of common shares under Normal Course Issuer Bid	**(6)**	–
Balance – end of year	**3,147**	2,834
Retained earnings		
Balance – beginning of year	**16,696**	15,344
Net earnings	**1,697**	1,580
Purchase of common shares under Normal Course Issuer Bid (note 7)	**(62)**	–
Dividends on common shares (note 7)	**(326)**	(228)
Balance – end of year	**18,005**	16,696
Accumulated other comprehensive loss (note 8)		
Balance – beginning of year	**(104)**	262
Other comprehensive loss, net of taxes	**(63)**	(366)
Balance – end of year	**(167)**	(104)
Shareholders' equity	**$ 20,985**	$ 19,426

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2010	Dec 31 2009	Year Ended Dec 31 2010	Dec 31 2009
Net earnings (loss)	**$ (416)**	$ 455	**$ 1,697**	$ 1,580
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized loss during the period, net of taxes of $6 million (2009 – $1 million) – three months ended; $11 million (2009 – $5 million) – year ended	**(46)**	(9)	**(24)**	(33)
Reclassification to net earnings, net of taxes of $nil (2009 – $nil) – three months ended; $1 million (2009 – $1 million) – year ended	**–**	–	**(4)**	(10)
	(46)	(9)	**(28)**	(43)
Foreign currency translation adjustment				
Translation of net investment	**(24)**	(34)	**(35)**	(323)
Other comprehensive loss, net of taxes	**(70)**	(43)	**(63)**	(366)
Comprehensive income (loss)	**$ (486)**	$ 412	**$ 1,634**	$ 1,214

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2010**	Three Months Ended Dec 31 2009	Year Ended **Dec 31 2010**	Year Ended Dec 31 2009
Operating activities				
Net earnings (loss)	**$ (416)**	$ 455	**$ 1,697**	$ 1,580
Non-cash items				
Depletion, depreciation and amortization	**1,578**	836	**4,036**	2,819
Asset retirement obligation accretion	**27**	23	**107**	90
Stock-based compensation expense	**336**	87	**294**	355
Unrealized risk management loss (gain)	**173**	308	**(25)**	1,991
Unrealized foreign exchange gain	**(120)**	(88)	**(180)**	(661)
Deferred petroleum revenue tax expense	**5**	7	**28**	15
Future income tax expense (recovery)	**58**	75	**364**	(99)
Other	**5**	3	**(7)**	5
Abandonment expenditures	**(80)**	(17)	**(179)**	(48)
Net change in non-cash working capital	**(63)**	(180)	**149**	(235)
	1,503	1,509	**6,284**	5,812
Financing activities				
Issue (repayment) of bank credit facilities, net	**622**	(717)	**(472)**	(2,021)
Repayment of medium-term notes	**(400)**	–	**(400)**	–
Repayment of senior unsecured notes	**–**	–	**–**	(34)
Issue of common shares on exercise of stock options	**87**	3	**170**	24
Purchase of common shares under Normal Course Issuer Bid	**–**	–	**(68)**	–
Dividends on common shares	**(82)**	(57)	**(302)**	(225)
Net change in non-cash working capital	**31**	36	**(5)**	(12)
	258	(735)	**(1,077)**	(2,268)
Investing activities				
Expenditures on property, plant, and equipment	**(1,872)**	(680)	**(5,335)**	(2,985)
Proceeds on sale of property, plant and equipment	**5**	3	**8**	36
Net expenditures on property, plant and equipment	**(1,867)**	(677)	**(5,327)**	(2,949)
Net change in non-cash working capital	**101**	(98)	**129**	(609)
	(1,766)	(775)	**(5,198)**	(3,558)
(Decrease) increase in cash and cash equivalents	**(5)**	(1)	**9**	(14)
Cash and cash equivalents – beginning of period	**27**	14	**13**	27
Cash and cash equivalents – end of period	**$ 22**	$ 13	**$ 22**	$ 13
Interest paid	**$ 89**	$ 83	**$ 471**	$ 516
Taxes paid				
Taxes other than income tax	**$ 33**	$ 18	**$ 102**	$ 52
Current income tax	**$ 66**	$ 88	**$ 111**	$ 216

Notes to the consolidated financial statements (tabular amounts in millions of Canadian dollars, unless otherwise stated, 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, 2009. 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 interim financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2009.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2010.

Common share, per common share, and stock option data has been restated to reflect the two-for-one share split in May 2010.

2. CHANGES IN ACCOUNTING POLICIES

International Financial Reporting Standards

In February 2008, the Canadian Institute of Chartered Accountants' Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of generally accepted accounting principles in Canada ("GAAP") effective January 1, 2011.

3. OTHER LONG–TERM ASSETS

	Dec 31 2010	Dec 31 2009
Other	**$ 25**	$ 18

4. LONG–TERM DEBT

	Dec 31 2010	Dec 31 2009
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 1,436**	$ 1,897
Medium-term notes	**800**	1,200
	2,236	3,097
US dollar denominated debt		
US dollar debt securities (US$6,300 million)	**6,266**	6,594
Less: original issue discount on US dollar debt securities (1)	**(20)**	(22)
	6,246	6,572
Fair value of interest rate swaps on US dollar debt securities (2)	**61**	38
	6,307	6,610
Long-term debt before transaction costs	**8,543**	9,707
Less: transaction costs (1) (3)	**(44)**	(49)
	$ 8,499	$ 9,658

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank credit facilities

As at December 31, 2010, the Company had in place unsecured bank credit facilities of $3,953 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2010 was 1.5% (December 31, 2009 – 0.8%), and on total long-term debt outstanding for the three months ended December 31, 2010 was 5.7% (December 31, 2009 – 4.5%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $283 million, including $205 million related to Horizon, were outstanding at December 31, 2010. Subsequent to December 31, 2010, the financial guarantee related to Horizon was reduced to $190 million.

Medium-term notes

During the fourth quarter of 2010, the Company repaid $400 million of medium-term notes bearing interest at 5.50%.

The Company filed a $3,000 million base shelf prospectus in October 2009 that allows for the issue of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

US dollar debt securities

During the fourth quarter of 2010, the Company unwound the interest rate swaps previously designated as a fair value hedge of US$350 million of 4.90% unsecured notes due December 2014. Accordingly, the Company ceased revaluing the related debt for subsequent changes in fair value from the date of unwind. The fair value adjustment of $55 million at the date of unwind is being amortized to interest expense over the remaining term of the debt.

The Company filed a US$3,000 million base shelf prospectus in October 2009 that allows for the issue of US dollar debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

5. OTHER LONG–TERM LIABILITIES

	Dec 31 2010	Dec 31 2009
Asset retirement obligations	**$ 1,779**	$ 1,610
Stock-based compensation	**516**	392
Risk management (note 11)	**451**	309
Other	**103**	180
	2,849	2,491
Less: current portion	**719**	643
	$ 2,130	$ 1,848

Asset retirement obligations

At December 31, 2010, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $7,232 million (December 31, 2009 – $6,606 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk-free rate of 6.6% (December 31, 2009 – 6.9%). A reconciliation of the discounted asset retirement obligations is as follows:

	Year Ended Dec 31, 2010	Year Ended Dec 31, 2009
Balance – beginning of year	**$ 1,610**	$ 1,064
Liabilities incurred (1)	**12**	299
Liabilities acquired	**22**	–
Liabilities settled	**(179)**	(48)
Asset retirement obligation accretion	**107**	90
Revision of estimates	**240**	276
Foreign exchange	**(33)**	(71)
Balance – end of year	**$ 1,779**	$ 1,610

(1) During 2009, the Company recognized additional asset retirement obligations related to Oil Sands Mining and Upgrading and Gabon, Offshore West Africa.

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 twelve-month period if all vested options are surrendered for cash settlement.

	Year Ended Dec 31, 2010	Year Ended Dec 31, 2009
Balance – beginning of year	**$ 392**	$ 171
Stock-based compensation expense	**294**	355
Cash payments for options surrendered	**(45)**	(94)
Transferred to common shares	**(149)**	(42)
Capitalized to Oil Sands Mining and Upgrading	**24**	2
Balance – end of year	**516**	392
Less: current portion	**472**	365
	$ 44	$ 27

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Year Ended	
	Dec 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Current income tax – North America (1)	**$ 49**	$ 11	**$ 432**	$ 28
Current income tax – North Sea	**84**	60	**203**	278
Current income tax – Offshore West Africa	**23**	23	**63**	82
Current income tax expense	**156**	94	**698**	388
Future income tax expense (recovery)	**58**	75	**364**	(99)
Income tax expense	**$ 214**	$ 169	**$ 1,062**	$ 289

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

Taxable income from the exploration and production business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

Future income tax expense in the first quarter of 2010 included a charge of $83 million related to enacted changes in Canada to the taxation of stock options surrendered by employees for cash. During the first quarter of 2009, enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities that might ultimately arise from these reassessments will be material.

7. SHARE CAPITAL

	Year Ended Dec 31, 2010	
Issued Common shares	**Number of shares** (thousands)[1]	**Amount**
Balance – beginning of year	**1,084,654**	**$ 2,834**
Issued upon exercise of stock options	**8,208**	**170**
Previously recognized liability on stock options exercised for common shares	**–**	**149**
Cancellation of common shares	**(14)**	**–**
Purchase of common shares under Normal Course Issuer Bid	**(2,000)**	**(6)**
Balance – end of year	**1,090,848**	**$ 3,147**

(1) Restated to reflect two-for-one common share split in May 2010.

Dividend Policy

On March 1, 2011, the Board of Directors set the regular quarterly dividend at $0.09 per common share (2010 – $0.075 per common share). The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Normal Course Issuer Bid

In 2010, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the 12 month period commencing April 6, 2010 and ending April 5, 2011, up to 27,163,940 common shares or 2.5% of the common shares of the Company outstanding at March 17, 2010. As at December 31, 2010, the Company purchased 2,000,000 common shares for cancellation at an average price of $33.77 per common share, for a total cost of $68 million. Retained earnings was reduced by $62 million, representing the excess of the purchase price of the common shares over their average carrying value.

Share split

The Company's shareholders passed a Special Resolution subdividing the common shares of the Company on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2010 with such subdivision taking effect in May 2010. All common share, per common share, and stock option amounts have been restated to reflect the share split.

	Year Ended Dec 31, 2010		
Stock options	**Stock options** (thousands)[1]		**Weighted average exercise price**[1]
Outstanding – beginning of year	**64,211**	**$**	**29.27**
Granted	**16,168**	**$**	**40.68**
Surrendered for cash settlement	**(2,741)**	**$**	**21.00**
Exercised for common shares	**(8,208)**	**$**	**20.66**
Forfeited	**(2,586)**	**$**	**32.30**
Outstanding – end of year	**66,844**	**$**	**33.31**
Exercisable – end of year	**23,668**	**$**	**30.64**

(1) Restated to reflect two-for-one common share split in May 2010.

8. ACCUMULATED OTHER COMPREHENSIVE LOSS

The components of accumulated other comprehensive loss, net of taxes, were as follows:

		Dec 31 2010		Dec 31 2009
Derivative financial instruments designated as cash flow hedges	**$**	**48**	$	76
Foreign currency translation adjustment		**(215)**		(180)
	$	**(167)**	$	(104)

9. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2010, the ratio was below the target range at 29%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Dec 31 2010	Dec 31 2009
Long-term debt	**$ 8,499**	$ 9,658
Total shareholders' equity	**$ 20,985**	$ 19,426
Debt to book capitalization	**29%**	33%

10. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Weighted average common shares outstanding (thousands) – basic and diluted (1)	**1,088,993**	1,084,600	**1,088,096**	1,083,850
Net earnings (loss) – basic and diluted	**$ (416)**	$ 455	**$ 1,697**	$ 1,580
Net earnings (loss) per common share – basic and diluted (1)	**$ (0.38)**	$ 0.42	**$ 1.56**	$ 1.46

(1) Restated to reflect two-for-one common share split in May 2010.

11. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	Dec 31, 2010		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 22**	**$ –**
Accounts receivable	**1,481**	**–**	**–**
Accounts payable	**–**	**–**	**(274)**
Accrued liabilities	**–**	**–**	**(2,163)**
Other long-term liabilities	**–**	**(451)**	**(91)**
Long-term debt	**–**	**–**	**(8,499)**
	$ 1,481	**$ (429)**	**$ (11,027)**

	Dec 31, 2009		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 13	$ –
Accounts receivable	1,148	–	–
Accounts payable	–	–	(240)
Accrued liabilities	–	–	(1,522)
Other long-term liabilities	–	(309)	(167)
Long-term debt	–	–	(9,658)
	$ 1,148	$ (296)	$ (11,587)

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below. The fair values of the Company's financial assets and liabilities are outlined below:

	Dec 31, 2010					
	Carrying value		**Fair value**			
Asset (liability) [1]				**Level 1**		**Level 2**
Other long-term liabilities	**$**	**(451)**	**$**	**–**	**$**	**(451)**
Fixed-rate long-term debt[2][3]		**(7,063)**		**(7,835)**		**–**
	$	**(7,514)**	**$**	**(7,835)**	**$**	**(451)**

	Dec 31, 2009					
	Carrying value		Fair value			
Asset (liability) [1]				Level 1		Level 2
Other long-term liabilities	$	(309)	$	–	$	(309)
Fixed-rate long-term debt[2][3]		(7,761)		(8,212)		–
	$	(8,070)	$	(8,212)	$	(309)

(1) Excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $61 million (2009 – $38 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

Risk management

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 speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

	Year Ended Dec 31, 2010	Year Ended Dec 31, 2009
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of year	**$ (309)**	$ 2,119
Net cost of outstanding put options	**106**	–
Net change in fair value of outstanding derivative financial instruments attributable to:		
– Risk management activities	**25**	(1,991)
– Interest expense	**30**	(25)
– Foreign exchange	**(101)**	(338)
– Other comprehensive income	**(41)**	(78)
– Settlement of interest rate swaps and other	**(55)**	4
	(345)	(309)
Add: put premium financing obligations (1)	**(106)**	–
Balance – end of year	**(451)**	(309)
Less: current portion	**(222)**	(182)
	$ (229)	$ (127)

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net losses (gains) from risk management activities were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Net realized risk management loss (gain)	**$ 26**	$ (122)	**$ (96)**	$ (1,253)
Net unrealized risk management loss (gain)	**173**	308	**(25)**	1,991
	$ 199	$ 186	**$ (121)**	$ 738

Financial risk factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2010, the Company had the following net derivative financial instruments outstanding:

i) Sales Contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars	Jan 2011	–	Dec 2011	50,000 bbl/d	US$70.00	–	US$102.23	WTI
Crude oil puts	Jan 2011	–	Dec 2011	100,000 bbl/d			US$70.00	WTI

The cost of outstanding put options and their respective periods of settlement are as follows:

	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Cost ($ millions)	US$26	US$26	US$27	US$27

ii) Purchase Contracts

	Remaining term			Volume	Weighted average fixed rate	Floating index
Natural gas						
Swaps – floating to fixed	Jan 2011	–	Dec 2011	125,000 GJ/d	C$4.87	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

The natural gas derivative financial instruments designated as hedges at December 31, 2010 were classified as cash flow hedges.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts 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 amounts on which the payments are based. At December 31, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount	Fixed rate	Floating rate
Interest rate (1) (2)						
Swaps – floating to fixed	Jan 2011	–	Feb 2012	C$200	1.4475%	3 month CDOR (3)

(1) During the fourth quarter of 2010, the Company unwound US$350 million of 4.9% interest rate swaps for proceeds of US$54 million.

(2) During the fourth quarter of 2010, the Company unwound C$300 million of 1.0680% interest rate swaps for nominal consideration.

(3) Canadian Dealer Offered Rate.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. 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. At December 31, 2010 the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps (1)	Jan 2011	–	Jul 2011	US$150	0.999	6.70%	7.70%
	Jan 2011	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2011	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2011	–	Mar 2038	US$550	1.170	6.25%	5.76%

(1) Subsequent to December 31, 2010, the Company entered into cross currency swap contracts for US$50 million with an exchange rate of $0.994 (US$/C$) and average interest rates of 6.70% (US$) and 7.88% (C$) for the period January to July 2011.

All cross currency swap derivative financial instruments designated as hedges at December 31, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2010 the Company had US$1,162 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2010 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (7)	$ –
Decrease WTI US$1.00/bbl	$ 7	$ –
Increase AECO C$0.10/mcf	$ –	$ 3
Decrease AECO C$0.10/mcf	$ –	$ (3)
Interest rate risk		
Increase interest rate 1%	$ (8)	$ 22
Decrease interest rate 1%	$ 8	$ (31)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (27)	$ –
Decrease exchange rate by US$0.01	$ 27	$ –

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2010, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2010, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2009 – $7 million).

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	274	$	–	$	–	$	–
Accrued liabilities	$	2,163	$	–	$	–	$	–
Risk management	$	222	$	32	$	96	$	101
Other long-term liabilities	$	25	$	25	$	41	$	–
Long-term debt (1)	$	398	$	348	$	1,546	$	4,774

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,436 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at December 31, 2010, the Company had committed to certain payments as follows:

		2011		2012		2013		2014		2015		Thereafter
Product transportation and pipeline	$	228	$	199	$	172	$	164	$	152	$	932
Offshore equipment operating leases	$	141	$	98	$	97	$	97	$	81	$	168
Offshore drilling	$	7	$	–	$	–	$	–	$	–	$	–
Asset retirement obligations (1)	$	18	$	17	$	19	$	28	$	27	$	7,123
Office leases	$	27	$	27	$	28	$	28	$	32	$	339
Other	$	102	$	66	$	19	$	16	$	24	$	10

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2011 – 2015 represent the estimated minimum expenditures required to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore West Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**2,516**	2,220	**9,713**	7,973	**303**	295	**1,058**	961	**261**	307	**884**	913	**3,080**	2,822	**11,655**	9,847
Less: royalties	**(385)**	(244)	**(1,267)**	(825)	**(1)**	(1)	**(2)**	(2)	**(22)**	(22)	**(62)**	(81)	**(408)**	(267)	**(1,331)**	(908)
Segmented revenue, net of royalties	**2,131**	1,976	**8,446**	7,148	**302**	294	**1,056**	959	**239**	285	**822**	832	**2,672**	2,555	**10,324**	8,939
Segmented expenses																
Production	**416**	391	**1,675**	1,748	**105**	103	**385**	376	**46**	63	**167**	179	**567**	557	**2,227**	2,303
Transportation and blending	**456**	346	**1,761**	1,213	**1**	2	**8**	8	**–**	–	**1**	1	**457**	348	**1,770**	1,222
Depletion, depreciation and amortization	**608**	487	**2,336**	2,060	**81**	65	**303**	261	**791**	202	**1,023**	335	**1,480**	754	**3,662**	2,656
Asset retirement obligation accretion	**13**	11	**46**	41	**8**	5	**33**	24	**1**	1	**6**	4	**22**	17	**85**	69
Realized risk management activities	**26**	(78)	**(96)**	(880)	**–**	(44)	**–**	(373)	**–**	–	**–**	–	**26**	(122)	**(96)**	(1,253)
Total segmented expenses	**1,519**	1,157	**5,722**	4,182	**195**	131	**729**	296	**838**	266	**1,197**	519	**2,552**	1,554	**7,648**	4,997
Segmented earnings (loss) before the following	**612**	819	**2,724**	2,966	**107**	163	**327**	663	**(599)**	19	**(375)**	313	**120**	1,001	**2,676**	3,942
Non-segmented expenses																
Administration																
Stock-based compensation expense																
Interest, net																
Unrealized risk management activities																
Foreign exchange gain																
Total non-segmented expenses																
Earnings (loss) before taxes																
Taxes other than income tax																
Current income tax expense																
Future income tax expense (recovery)																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**700**	492	**2,649**	1,253	**20**	18	**79**	72	**(13)**	(13)	**(61)**	(94)	**3,787**	3,319	**14,322**	11,078
Less: royalties	**(23)**	(18)	**(90)**	(36)	**–**	–	**–**	–	**–**	–	**–**	8	**(431)**	(285)	**(1,421)**	(936)
Segmented revenue, net of royalties	**677**	474	**2,559**	1,217	**20**	18	**79**	72	**(13)**	(13)	**(61)**	(86)	**3,356**	3,034	**12,901**	10,142
Segmented expenses																
Production	**304**	259	**1,208**	683	**6**	5	**22**	19	**(3)**	(2)	**(10)**	(18)	**874**	819	**3,447**	2,987
Transportation and blending	**15**	14	**61**	41	**–**	–	**–**	–	**(12)**	(11)	**(48)**	(45)	**460**	351	**1,783**	1,218
Depletion, depreciation and amortization	**96**	83	**366**	187	**2**	3	**8**	9	**–**	(4)	**–**	(33)	**1,578**	836	**4,036**	2,819
Asset retirement obligation accretion	**5**	6	**22**	21	**–**	–	**–**	–	**–**	–	**–**	–	**27**	23	**107**	90
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**26**	(122)	**(96)**	(1,253)
Total segmented expenses	**420**	362	**1,657**	932	**8**	8	**30**	28	**(15)**	(17)	**(58)**	(96)	**2,965**	1,907	**9,277**	5,861
Segmented earnings (loss) before the following	**257**	112	**902**	285	**12**	10	**49**	44	**2**	4	**(3)**	10	**391**	1,127	**3,624**	4,281
Non-segmented expenses																
Administration													**53**	49	**210**	181
Stock-based compensation expense													**336**	87	**294**	355
Interest, net													**120**	111	**449**	410
Unrealized risk management activities													**173**	308	**(25)**	1,991
Foreign exchange gain													**(114)**	(84)	**(182)**	(631)
Total non-segmented expenses													**568**	471	**746**	2,306
Earnings (loss) before taxes													**(177)**	656	**2,878**	1,975
Taxes other than income tax													**25**	32	**119**	106
Current income tax expense													**156**	94	**698**	388
Future income tax expense (recovery)													**58**	75	**364**	(99)
Net earnings (loss)													**(416)**	455	**1,697**	1,580

Net additions to property, plant and equipment

	Year Ended					
	Dec 31, 2010			Dec 31, 2009		
	Net Expenditures	**Non Cash/Fair Value Changes**[(1)]	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes[(1)]	Capitalized Costs
North America	**$ 4,369**	**$ 386**	**$ 4,755**	$ 1,663	$ 65	$ 1,728
North Sea	**149**	**(41)**	**108**	168	146	314
Offshore West Africa	**246**	**(10)**	**236**	544	111	655
Other	**3**	**–**	**3**	2	–	2
Oil Sands Mining and Upgrading [(2)]	**535**	**(59)**	**476**	553	355	908
Midstream	**7**	**–**	**7**	6	–	6
Head office	**18**	**–**	**18**	13	–	13
	$ 5,327	**$ 276**	**$ 5,603**	$ 2,949	$ 677	$ 3,626

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading assets also include capitalized interest, stock-based compensation, and the impact of inter-segment eliminations.

	Property, plant and equipment		Total assets	
	Dec 31 2010	Dec 31 2009	**Dec 31 2010**	Dec 31 2009
Segmented assets				
North America	**$ 24,274**	$ 21,834	**$ 25,499**	$ 22,994
North Sea	**1,525**	1,812	**1,674**	1,968
Offshore West Africa [(1)]	**978**	1,883	**1,186**	2,033
Other	**31**	28	**46**	42
Oil Sands Mining and Upgrading	**13,401**	13,295	**13,865**	13,621
Midstream	**202**	203	**338**	306
Head office	**61**	60	**61**	60
	$ 40,472	$ 39,115	**$ 42,669**	$ 41,024

(1) Offshore West Africa property, plant and equipment has been reduced by $726 million (2009 - $115 million) to reflect the impact of a ceiling test impairment charge as at December 31, 2010.

Capitalized interest

The Company capitalizes construction period interest to Oil Sands Mining and Upgrading activities based on costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete. For the year ended December 31, 2010, pre-tax interest of $28 million was capitalized to Oil Sands Mining and Upgrading (December 31, 2009 – $106 million).

14. SUBSEQUENT EVENTS

On January 6, 2011, the Company suspended synthetic crude oil production at its Oil Sands Mining and Upgrading operations due to a fire in the primary upgrading coking plant. Production will recommence once plant operating capacity is restored and all necessary regulatory and operating approvals are received.

The Company believes that it has adequate insurance coverage to mitigate all significant property-damage related losses. The Company also maintains business interruption coverage, subject to a waiting period, which it believes will mitigate operating losses related to on-going operations.

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 October 2009. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2010:

Interest coverage (times)	
Net earnings (1)	6.7x
Cash flow from operations (2)	15.7x

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

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, March 3, 2011. The North American conference call number is 1-800-769-8320 and the outside North American conference call number is 001-416-695-6616. 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 website at www.cnrl.com.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 10, 2011. To access the postview in North America, dial 1-800-408-3053. Those outside of North America, dial 001-905-694-9451. The passcode to use is 4207622.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

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