Canadian Natural

THIRD QUARTER REPORT — NINE MONTHS ENDED SEPTEMBER 30, 2010

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2010 THIRD QUARTER RESULTS

Canadian Natural's Chairman, Allan Markin stated, "We have achieved good overall corporate performance across our assets during the third quarter. Our people remain committed towards safe, effective operations and cost optimization. At Horizon, we continue to make operational adjustments to optimize a strong long-life asset that adds to the diversity and cash flow generating capacity of our portfolio."

John Langille, Vice-Chairman of Canadian Natural commented, "Our strategy to steward capital to the highest return projects continued to generate significant free cash flow in the third quarter. We have increased our nine-month total production volumes by over 9% from 2009 levels, and at the same time we have effectively utilized our free cash flow to reduce debt, increase dividend payments, and buy back common shares to reduce dilution and complete acquisitions that support our corporate strategy."

Steve Laut, President for Canadian Natural concluded, "Canadian Natural is in a strong position; our balanced asset base enables us to allocate capital to maximize shareholder value. Our flexibility allows us to adjust when commodity cycles change and currently this means choosing crude oil projects over natural gas projects. We remain disciplined in our approach to growing the Company, and this strategy ensures we add value growth in the near, mid and long term, while maintaining a solid balance sheet."

	Three Months Ended			Nine Months Ended	
($ millions, except as noted)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009(1)	**Sep 30 2010**	Sep 30 2009(1)
Net earnings	**$ 580**	$ 667	$ 658	**$ 2,113**	$ 1,125
Per common share, basic and diluted	**$ 0.53**	$ 0.61	$ 0.61	**$ 1.94**	$ 1.04
Adjusted net earnings from operations (2)	**$ 606**	$ 688	$ 658	**$ 1,952**	$ 2,022
Per common share, basic and diluted	**$ 0.55**	$ 0.63	$ 0.61	**$ 1.79**	$ 1.87
Cash flow from operations (3)	**$ 1,545**	$ 1,630	$ 1,506	**$ 4,680**	$ 4,387
Per common share, basic and diluted	**$ 1.42**	$ 1.49	$ 1.39	**$ 4.30**	$ 4.05
Capital expenditures, net of dispositions	**$ 914**	$ 1,573	$ 574	**$ 3,559**	$ 2,303
Daily production, before royalties					
Natural gas (mmcf/d)	**1,258**	1,237	1,293	**1,240**	1,338
Crude oil and NGLs (bbl/d)	**411,585**	443,045	359,269	**420,319**	351,760
Equivalent production (boe/d)	**621,284**	649,195	574,755	**627,052**	574,688

(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.

HIGHLIGHTS

- Total natural gas production for Q3/10 averaged 1,258 mmcf/d. Q3/10 natural gas production decreased 3% from Q3/09, as expected, and increased 2% from the previous quarter. The increase from Q2/10 reflects a full quarter of production volumes from acquisitions in Q2/10 and the Company's high quality North American natural gas assets.

- Total crude oil and NGLs production for Q3/10 averaged 411,585 bbl/d, a 15% increase from Q3/09 and a 7% decrease from Q2/10. Lower production volumes in Q3/10 compared to Q2/10 mainly reflected lower Horizon volumes as well as the optimization of current steaming strategies at Primrose to maximize ultimate recoveries. As a result, the production portion of the cycle was delayed on new pads to capture this opportunity. Consequently, thermal crude oil production volumes in Q3/10 are targeted to increase in Q4/10 and Q1/11.

- Quarterly cash flow from operations for Q3/10 exceeded $1.5 billion, an increase of 3% from Q3/09 and decreased 5% from Q2/10. The decrease from Q2/10 largely reflects the impact of lower crude oil and NGL sales volumes.

- In Q3/10, Canadian Natural drilled 209 net primary heavy crude oil wells as part of the ongoing record heavy crude oil drilling program in 2010. The Company targets to drill approximately 650 net primary heavy crude oil wells in 2010.

- Horizon SCO production averaged 83,809 bbl/d in Q3/10. The maintenance required to address localized pipe wall thinning limited to the amine unit, which required a plant wide shut down, was successfully completed in mid August. This lowered August's volumes to approximately 50,500 bbl/d while production increased to approximately 108,600 bbl/d in September 2010.

- The last well on Platform B of the Olowi Project was completed during Q3/10 and performance is in line with the Company's expectations. The Company has commenced drilling operations on Platform A and during October 2010, the first crude oil well came on production as expected at 2,500 bbl/d.

- During Q3/10, Canadian Natural received regulatory approval for the Kirby In Situ Oil Sands Project.

- In early October 2010, additional leases adjacent to Canadian Natural's Kirby development were acquired, adding best estimate contingent resources of 520 million barrels of bitumen. The Kirby development will be expanded to include three phases; Kirby Phase 1 (with regulatory approval as noted above), Kirby Phase 2 and Kirby Debottleneck Phase. Overall production capabilities are targeted to range between 70,000 and 100,000 bbl/d for all three Phases. 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.

- Subsequent to Q3/10, the Board of Directors sanctioned Kirby Phase 1. Canadian Natural targets to commence Kirby Phase 1 construction in Q4/10, first steam-in for 2013 and peak production at 40,000 bbl/d. The overall cost of Kirby Phase 1 is targeted to be $1.25 billion.

- The Company's balance sheet continues to strengthen with long term debt reductions of approximately $1.2 billion in 2010, after completing over $1.0 billion of acquisitions during the first nine months of 2010.

- As a result of improving credit metrics, Moody's Investors Service upgraded the Company's rating to Baa1 from Baa2. Standard & Poor's reaffirmed its BBB rating, however changed its outlook to positive. The DBRS Limited rating for Canadian Natural is BBB (high) with a stable outlook.

- Repurchased two million common shares under the Company's Normal Course Issuer Bid.

- Declared a quarterly cash dividend on common shares of $0.075 per common share payable January 1, 2011.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointments of Timothy W. Faithfull, Christopher L. Fong and Wilfred A. Gobert to the Board of Directors of the Company.

Mr. Faithfull had a 36 year career in various senior positions with Royal Dutch/Shell, most recently as President and CEO of Shell Canada Limited, retiring in 2003. He obtained his MA Philosophy, Politics, and Economics from Keble College, Oxford and attended the Senior Executive Programme at the London Business School. Mr. Faithfull serves as a director on two other boards of senior publicly traded Canadian corporations, a FTSE 100 UK public company, sits on a number of not-for profit boards and is a Distinguished Friend of the London Business School.

Mr. Fong, after 28 years with a Canadian chartered bank, retired in 2009 as Global Head, Corporate Banking, Energy, with RBC Capital Markets. In his energy career of over 35 years, he developed a strategic and operational perspective of the energy industry, both in Canada and abroad. Mr. Fong has a Bachelor degree in Chemical Engineering and is a professional engineer in the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA). He is a director of two other publicly traded companies and sits on a number of not-for-profit boards.

Mr. Gobert, spent 33 years as a securities industry financial analyst, primarily as an analyst on the petroleum industry with Peters & Co. Limited where he was Director, Research before becoming Vice-Chairman in 2002 serving on its Board of Directors and Executive Committee until his retirement in May 2006. Mr. Gobert holds a CFA designation and has an MBA and B. Sc (Honours) degree. He currently serves on three other publicly traded company boards and sits on a number of not-for-profit boards and is Senior Fellow, Energy Studies, Centre for Energy Policy Studies with The Fraser Institute.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Sep 30, 2010 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2010 (net wells) (1)
North America		
Northeast British Columbia	**2,040**	**30.9**
Northwest Alberta	**1,523**	**47.7**
Northern Plains	**5,436**	**593.9**
Southern Plains	**789**	**17.7**
Southeast Saskatchewan	**144**	**25.1**
Thermal In Situ Oil Sands	**675**	**192.0**
	10,607	**907.3**
Oil Sands Mining and Upgrading	**115**	**121.0**
North Sea	**150**	**0.9**
Offshore West Africa	**4,193**	**5.6**
	15,065	**1,034.8**

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

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2010		2009	
	Gross	**Net**	Gross	Net
Crude oil	**663**	**616**	476	449
Natural gas	**90**	**74**	107	81
Dry	**30**	**25**	32	29
Subtotal	**783**	**715**	615	559
Stratigraphic test / service wells	**321**	**320**	249	249
Total	**1,104**	**1,035**	864	808
Success rate (excluding stratigraphic test / service wells)		**97%**		95%

North America

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Natural gas production (mmcf/d)	**1,234**	1,219	1,264	**1,216**	1,311
Net wells targeting natural gas	**19**	11	17	**79**	89
Net successful wells drilled	**19**	10	17	**74**	81
Success rate	**100%**	91%	100%	**94%**	91%

- North America natural gas production volumes averaged 1,234 mmcf/d, in line with the Company's expectations for Q3/10. Volumes decreased 2%, as expected, from Q3/09. The Company continues to optimize performance on existing assets while implementing a limited natural gas drilling program. Production increased 1% from Q2/10 primarily due to a full quarter of production volumes from acquisitions completed in Q2/10 and the high grading of natural gas drilling inventory within the Company's portfolio.
- As at September 30, 2010, the Company has shut in approximately 35 mmcf/d due to low natural gas pricing.
- Operating costs for natural gas in Q3/10 were comparable to Q3/09 costs at $1.04 per mcf while production decreased by 2% from Q3/09. This demonstrates the effectiveness of the Company's focus on operating efficiencies and as a result, 2010 annual midpoint operating cost guidance has been lowered to between $1.05 and $1.10 per mcf.
- Canadian Natural targeted 19 net natural gas wells in Q3/10 with a prudent program across the Company's core regions. In Northeast British Columbia, 4 net natural gas wells were drilled, while in Northwest Alberta, 12 net natural gas wells were drilled. In the Northern Plains, 1 net natural gas well was drilled while in the Southern Plains, 2 net natural gas wells were drilled.
- Planned drilling activity for Q4/10 includes 20 net natural gas wells.

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs production (bbl/d)	**267,177**	275,584	223,307	**265,125**	236,315
Net wells targeting crude oil	**289**	91	270	**630**	464
Net successful wells drilled	**280**	90	260	**610**	443
Success rate	**97%**	99%	96%	**97%**	95%

- Q3/10 North America crude oil and NGLs production averaged 267,177 bbl/d, an increase of 20% from Q3/09, reflecting higher thermal volumes and the implementation of a strong primary heavy crude oil drilling program in 2010. Volumes decreased 3% from Q2/10 levels mainly reflecting the optimization of current steaming strategies at Primrose to maximize ultimate recoveries. As a result, the production portion of the cycle was delayed on new pads to capture this opportunity. Thermal crude oil production volumes from Q3/10 are targeted to increase in Q4/10 and Q1/11, and the 2010 annual midpoint production guidance for North America crude oil and NGLs has been narrowed to between 270,000 and 272,000 bbl/d.
- Operating costs for crude oil and NGLs, compared to Q3/09, decreased 18% and increased 6% from Q2/10. The decrease from Q3/09 was due to higher production volumes and the lower cost of natural gas used as fuel. The increase from Q2/10 was a result of the timing of thermal steaming cycles. Q3/10 operating costs remained within expectations, demonstrating the Company's commitment to effective operations and 2010 annual operating cost guidance remains between $12.00 and $13.00 per bbl.

- During Q3/10, Canadian Natural received regulatory approval for the Kirby In Situ Oil Sands Project.
- In early October 2010, additional leases adjacent to Canadian Natural's Kirby development were acquired, adding best estimate contingent resources of 520 million barrels of bitumen. The Kirby development will be expanded to include three phases; Kirby Phase 1 (with regulatory approval as noted above), Kirby Phase 2 and Kirby Debottleneck Phase. Overall production capabilities are targeted to range between 70,000 and 100,000 bbl/d for all three Phases. 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.
- Subsequent to Q3/10, the Board of Directors sanctioned Kirby Phase 1. Canadian Natural targets to commence Kirby Phase 1 construction in Q4/10, first steam-in for 2013 and peak production at 40,000 bbl/d. The overall cost of Kirby Phase 1 is targeted to be $1.25 billion.
- Production at Pelican Lake averaged approximately 38,000 bbl/d for Q3/10 compared to 37,000 bbl/d for Q3/09 and Q2/10 reflecting the effect of polymer flooding with further production increases anticipated in Q4/10. Polymer flood production response is typically seen 12 to 24 months after conversion to polymer flood and production increases from the Company's 2010 program are expected in late 2011/early 2012.
- Primary heavy crude oil production volumes increased 7% in Q3/10 compared to Q3/09 reflecting the Company's ongoing drilling program in 2010.
- During Q3/10, drilling activity targeted 289 net wells including 209 net wells targeting heavy crude oil, 39 net wells targeting Pelican Lake crude oil, 6 net wells targeting thermal crude oil, and 35 net wells targeting light crude oil.
- Excluding stratigraphic test and service wells, planned drilling activity for Q4/10 includes 351 net crude oil wells.

International

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil production (bbl/d)					
North Sea	**27,045**	37,669	34,034	**33,828**	38,891
Offshore West Africa	**33,554**	29,842	35,021	**31,126**	33,025
Natural gas production (mmcf/d)					
North Sea	**8**	9	8	**10**	9
Offshore West Africa	**16**	9	21	**14**	18
Net wells targeting crude oil	**0.9**	1.9	2.2	**5.6**	6.4
Net successful wells drilled	**0.9**	1.9	1.9	**5.6**	6.1
Success rate	**100%**	100%	86%	**100%**	95%

North Sea

- As expected, Q3/10 production decreased 21% from Q3/09 and 28% from Q2/10 due to planned maintenance shut downs at all of the production facilities. Production was further impacted due to an unplanned shutdown on the Ninian Field to repair the flare gas system. Production was reinstated within the quarter.
- Operating costs per barrel increased in Q3/10, which reflect lower production volumes and increased maintenance costs due to facility shutdowns. 2010 annual midpoint operating cost guidance has been narrowed to between $30.00 and $31.00 per bbl.
- The Company recommenced platform drilling operations at the beginning of Q3/10. One workover and an injector well were completed, and the Company is currently drilling one gross production well in the Ninian Field. Focus continues on maturing and high grading future drilling locations to maximize efficiencies and operational performance.

Offshore West Africa

- Offshore West Africa's crude oil production in Q3/10 decreased 4% from Q3/09 and increased 12% from Q2/10. As previously announced, Q2/10 production was impacted by a shut down planned at Espoir for installation of facilities upgrades. Q3/10 production volumes were within the Company's previously issued guidance range.
- Production at Olowi during Q3/10 was impacted by compressor failures on the Floating Production Storage and Offtake vessel limiting production capability.
- Crude oil production expense in Q3/10 decreased 25% from Q2/10 due to higher production volumes and a higher proportion of liftings from the Espoir Field. 2010 annual midpoint operating cost guidance has been narrowed to between $14.50 to $15.50 per bbl.
- The last well on Platform B of the Olowi Project was completed during Q3/10 and performance is in line with the Company's expectations. The Company has commenced drilling operations on Platform A and during October 2010, the first crude oil well came on production as expected at 2,500 bbl/d.

Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Synthetic crude oil production (bbl/d)	**83,809**	99,950	66,907	**90,240**	43,529

- Horizon SCO production averaged 83,809 bbl/d in Q3/10. The maintenance required to address localized pipe wall thinning limited to the amine unit, which required a plant wide shut down, was successfully completed in mid August. This lowered August's volumes to approximately 50,500 bbl/d while production increased to approximately 108,600 bbl/d in September 2010.
- Operational costs in Q3/10 averaged $34.35 per barrel of SCO (including approximately $3.15 per barrel of natural gas input costs), primarily due to the plant wide shut down required during August 2010. The Company has narrowed annual operating cost guidance, which include natural gas input costs, to between $33.00 to $37.00 per bbl of SCO for 2010.
- Engineering and procurement for Tranche 2 of the Phase 2/3 expansion is progressing with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs pricing					
WTI(1) benchmark price (US$/bbl)	**$ 76.21**	$ 77.99	$ 68.29	**$ 77.65**	$ 57.13
Western Canadian Select blend differential from WTI (%)	**20%**	18%	15%	**17%**	15%
SCO price (US$/bbl)	**$ 75.30**	$ 76.44	$ 67.20	**$ 77.02**	$ 56.95
Average realized pricing before risk management(2) (C$/bbl)	**$ 63.21**	$ 63.62	$ 62.90	**$ 65.10**	$ 54.17
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 3.53**	$ 3.66	$ 2.87	**$ 4.08**	$ 3.88
Average realized pricing before risk management (C$/mcf)	**$ 3.75**	$ 3.86	$ 3.80	**$ 4.26**	$ 4. 46

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

(2) Excludes SCO.

- In Q3/10, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI averaged 20%, compared to 18% in Q2/10. This widening of heavy crude oil differentials in Q3/10 and early Q4/10 largely resulted from two pipeline disruptions in the United States that occurred during Q3/10.
- During Q3/10, the Company contributed approximately 153,000 bbl/d of its heavy crude oil streams to the WCS blend.
- In Q1/10, the Company announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind ("BRIK") program. In Q2/10, the Government of Alberta announced that the proposal had been selected for exclusive negotiations following a comprehensive review. Further project development is dependent upon successful completion of these negotiations on commercially acceptable terms and final project sanction by the respective parties.

FINANCIAL REVIEW

- The financial position of the Company is robust and the Company 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 620,000 boe/d in Q3/10, with 94% of production located in G8 countries.
    - Financial stability and liquidity - cash flow from operations of $1.5 billion with available unused bank lines of $3.1 billion at September 30, 2010.
    - 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 28% and debt to EBITDA of 1.1 times.
- The Company's balance sheet continues to strengthen with long term debt reductions of approximately $1.2 billion in 2010, after completing over $1.0 billion of acquisitions during the first nine months of 2010.
- As a result of improving credit metrics, Moody's Investors Service upgraded the Company's rating to Baa1 from Baa2. Standard & Poor's reaffirmed its BBB rating, however changed its outlook to positive. The DBRS Limited rating for Canadian Natural is BBB (high) with a stable outlook.
- Repurchased two million common shares under the Company's Normal Course Issuer Bid.
- Declared a quarterly cash dividend on common shares of $0.075 per common share payable January 1, 2011.

OUTLOOK

The Company forecasts 2010 production levels before royalties to average between 1,242 and 1,250 mmcf/d of natural gas and between 423,000 and 430,000 bbl/d of crude oil and NGLs. Q4/10 production guidance before royalties is forecast to average between 1,248 and 1,273 mmcf/d of natural gas and between 432,000 and 456,000 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.

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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, 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 Horizon Oil Sands, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal Oil Sands Project 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 nine months ended September 30, 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. The financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("GAAP"). 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 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 nine and three months ended September 30, 2010 in relation to the comparable periods in 2009 and the second quarter of 2010. The accompanying tables form an integral part of this MD&A. This MD&A is dated November 2, 2010. 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			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009[(1)]	**Sep 30 2010**	Sep 30 2009[(1)]
Revenue, before royalties	**$ 3,341**	$ 3,614	$ 2,823	**$ 10,535**	$ 7,759
Net earnings	**$ 580**	$ 667	$ 658	**$ 2,113**	$ 1,125
Per common share – basic and diluted	**$ 0.53**	$ 0.61	$ 0.61	**$ 1.94**	$ 1.04
Adjusted net earnings from operations [(2)]	**$ 606**	$ 688	$ 658	**$ 1,952**	$ 2,022
Per common share – basic and diluted	**$ 0.55**	$ 0.63	$ 0.61	**$ 1.79**	$ 1.87
Cash flow from operations [(3)]	**$ 1,545**	$ 1,630	$ 1,506	**$ 4,680**	$ 4,387
Per common share – basic and diluted	**$ 1.42**	$ 1.49	$ 1.39	**$ 4.30**	$ 4.05
Capital expenditures, net of dispositions	**$ 914**	$ 1,573	$ 574	**$ 3,559**	$ 2,303

(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			*Nine Months Ended*	
($ millions)	***Sep 30 2010***	*Jun 30 2010*	*Sep 30 2009*	***Sep 30 2010***	*Sep 30 2009*
Net earnings as reported	***$ 580***	*$ 667*	*$ 658*	***$ 2,113***	*$ 1,125*
Stock-based compensation expense (recovery), net of tax [(a) (d)]	***18***	*(58)*	*126*	***(42)***	*196*
Unrealized risk management loss (gain), net of tax [(b)]	***71***	*(64)*	*217*	***(147)***	*1,213*
Unrealized foreign exchange (gain) loss, net of tax [(c)]	***(63)***	*143*	*(343)*	***(55)***	*(493)*
Effect of statutory tax rate and other legislative changes on future income tax liabilities [(d)]	***–***	*–*	*–*	***83***	*(19)*
Adjusted net earnings from operations	***$ 606***	*$ 688*	*$ 658*	***$ 1,952***	*$ 2,022*

(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) 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 proposed 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			Nine Months Ended	
($ millions)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Net earnings	**$ 580**	$ 667	$ 658	**$ 2,113**	$ 1,125
Non-cash items:					
Depletion, depreciation and amortization	**851**	836	673	**2,458**	1,983
Asset retirement obligation accretion	**28**	26	24	**80**	67
Stock-based compensation expense (recovery)	**18**	(58)	172	**(42)**	268
Unrealized risk management loss (gain)	**92**	(82)	274	**(198)**	1,683
Unrealized foreign exchange (gain) loss	**(75)**	165	(391)	**(60)**	(573)
Deferred petroleum revenue tax expense	**11**	5	13	**23**	8
Future income tax expense (recovery)	**40**	71	83	**306**	(174)
Cash flow from operations	**$ 1,545**	$ 1,630	$ 1,506	**$ 4,680**	$ 4,387

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2010 were $2,113 million compared to $1,125 million for the nine months ended September 30, 2009. Net earnings for the nine months ended September 30, 2010 included net unrealized after-tax income of $161 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation, and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax expenses of $897 million for the nine months ended September 30, 2009. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2010 were $1,952 million, compared to $2,022 million for the nine months ended September 30, 2009. The decrease in adjusted net earnings from the nine months ended September 30, 2009 was primarily due to higher production expense, higher royalty expense, lower realized risk management gains, higher depletion, depreciation and amortization expense, and the impact of the stronger Canadian dollar, partially offset by higher realized crude oil pricing, higher crude oil and NGL sales volumes including crude oil volumes associated with Horizon and realized foreign exchange gains.

Net earnings for the third quarter of 2010 were $580 million compared to $658 million for the third quarter of 2009 and $667 million for the prior quarter. Net earnings for the third quarter of 2010 included net unrealized after-tax expenses of $26 million related to the effects of risk management activities, fluctuations in foreign exchange rates and stock-based compensation, compared to net unrealized after-tax expenses of $21 million for the prior quarter. Excluding these items, adjusted net earnings from operations for the third quarter of 2010 were $606 million compared to $658 million for the third quarter of 2009 and $688 million for the prior quarter. The decrease in adjusted net earnings from the third quarter of 2009 was primarily due to the impact of higher production expense, higher royalty expense, higher depletion, depreciation and amortization expense, lower realized risk management gains and realized foreign exchange losses, partially offset by higher sales volumes including crude oil volumes associated with Horizon.

The decrease in adjusted net earnings from the prior quarter was primarily due to the impact of lower crude oil and NGL sales volumes, lower realized prices, higher production expense, higher depletion, depreciation and amortization expense, lower realized risk management gains and realized foreign exchange losses, partially offset by lower royalty expense.

The impacts of unrealized risk management activities, stock-based compensation, 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 nine months ended September 30, 2010 was $4,680 million compared to $4,387 million for the nine months ended September 30, 2009. Cash flow from operations for the third quarter of 2010 was $1,545 million compared to $1,506 million for the third quarter of 2009 and $1,630 million for the prior quarter. The increase in cash flow from operations from the comparable periods in 2009 was primarily due to the impact of higher realized crude oil and NGL pricing, higher crude oil and NGL sales volumes including crude oil volumes associated with Horizon, partially offset by higher production expense, higher royalty expense, lower realized risk management gains, higher cash taxes and realized foreign exchange gains and the impact of the stronger Canadian dollar. The decrease in cash flow from operations from the prior quarter was primarily due to the impact of lower crude oil and NGL sales volumes, lower realized crude oil and natural gas pricing, higher production expense and lower realized risk management gains, partially offset by lower royalty expense and lower cash taxes.

Total production before royalties for the nine months ended September 30, 2010 increased 9% to 627,052 boe/d from 574,688 boe/d for the nine months ended September 30, 2009. Total production before royalties for the third quarter of 2010 increased 8% to 621,284 boe/d from 574,755 boe/d for the third quarter of 2009 and decreased 4% from 649,195 boe/d for the prior quarter. Production for the third quarter of 2010 was slightly below 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)	**Sep 30 2010**	Jun 30 2010	Mar 31 2010(1)	Dec 31 2009(1)
Revenue, before royalties	**$ 3,341**	$ 3,614	$ 3,580	$ 3,319
Net earnings	**$ 580**	$ 667	$ 866	$ 455
Net earnings per common share				
– Basic and diluted	**$ 0.53**	$ 0.61	$ 0.80	$ 0.42

($ millions, except per common share amounts)	Sep 30 2009(1)	Jun 30 2009(1)	Mar 31 2009(1)	Dec 31 2008(1)
Revenue, before royalties	$ 2,823	$ 2,750	$ 2,186	$ 2,511
Net earnings	$ 658	$ 162	$ 305	$ 1,770
Net earnings per common share				
– Basic and diluted	$ 0.61	$ 0.15	$ 0.28	$ 1.64

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

Volatility in quarterly net earnings 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 fluctuations in 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 and the impact of the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- **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 include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
WTI benchmark price (US$/bbl) (1)	**$ 76.21**	$ 77.99	$ 68.29	**$ 77.65**	$ 57.13
Dated Brent benchmark price (US$/bbl)	**$ 76.85**	$ 78.27	$ 68.28	**$ 77.15**	$ 57.26
WCS blend differential from WTI (US$/bbl)	**$ 15.60**	$ 14.12	$ 10.06	**$ 12.95**	$ 8.83
WCS blend differential from WTI (%)	**20%**	18%	15%	**17%**	15%
SCO price (US$/bbl) (2)	**$ 75.30**	$ 76.44	$ 67.20	**$ 77.02**	$ 56.95
Condensate benchmark price (US$/bbl)	**$ 74.52**	$ 82.81	$ 65.80	**$ 80.68**	$ 55.93
NYMEX benchmark price (US$/mmbtu)	**$ 4.42**	$ 4.08	$ 3.42	**$ 4.62**	$ 3.96
AECO benchmark price (C$/GJ)	**$ 3.53**	$ 3.66	$ 2.87	**$ 4.08**	$ 3.88
US / Canadian dollar average exchange rate	**$ 0.9624**	$ 0.9731	$ 0.9108	**$ 0.9656**	$ 0.8549

(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$77.65 per bbl for the nine months ended September 30, 2010, an increase of 36% from US$57.13 per bbl for the nine months ended September 30, 2009. WTI averaged US$76.21 per bbl for the third quarter of 2010, an increase of 12% from US$68.29 per bbl for the third quarter of 2009, and a decrease of 2% from US$77.99 per bbl in the prior quarter. WTI pricing was reflective of the overall balanced supply and demand environment, with strong Asian demand offsetting the demand decline related to the economic downturn from the past year.

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$77.15 per bbl for the nine months ended September 30, 2010, an increase of 35% compared to US$57.26 per bbl for the nine months ended September 30, 2009. Brent averaged US$76.85 per bbl for the third quarter of 2010, an increase of 13% compared to US$68.28 per bbl for the third quarter of 2009, and a decrease of 2% from US$78.27 per bbl for the prior quarter. High inventory levels of crude at Cushing during the second and third quarters resulted in Brent prices exceeding WTI.

The Western Canadian Select ("WCS") Heavy Differential averaged 17% for the nine months ended September 30, 2010 compared to 15% for the nine months ended September 30, 2009. The WCS Heavy Differential widened in the third quarter of 2010, averaging 20% compared to 15% for the third quarter of 2009 and 18% for the prior quarter, partially due to pipeline disruptions that forced the shutdown of two 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 third quarter of 2010, condensate traded at a discount to WTI, compared to a premium 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$4.62 per mmbtu for the nine months ended September 30, 2010, an increase of 17% from US$3.96 per mmbtu for the nine months ended September 30, 2009. NYMEX natural gas prices averaged US$4.42 per mmbtu for the third quarter of 2010, an increase of 29% from US$3.42 per mmbtu for the third quarter of 2009, and an increase of 8% from US$4.08 per mmbtu for the prior quarter. AECO natural gas prices for the nine months ended September 30, 2010 averaged $4.08 per GJ, an increase of 5% from $3.88 per GJ for the nine months ended September 30, 2009. AECO natural gas prices for the third quarter of 2010 increased 23% to average $3.53 per GJ from $2.87 per GJ in the third quarter of 2009, and decreased 4% from $3.66 per GJ for the prior quarter. Demand from the price sensitive power and industrial sectors and hot weather patterns in the Northeast part of the United States temporarily offset the strong incremental production from shale gas plays. Although natural gas prices have recovered compared to a weak 2009 price environment, strong US natural gas production is limiting the upside to natural gas price recovery.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs (bbl/d)					
North America – Conventional	**267,177**	275,584	223,307	**265,125**	236,315
North America – Oil Sands Mining and Upgrading	**83,809**	99,950	66,907	**90,240**	43,529
North Sea	**27,045**	37,669	34,034	**33,828**	38,891
Offshore West Africa	**33,554**	29,842	35,021	**31,126**	33,025
	411,585	443,045	359,269	**420,319**	351,760
Natural gas (mmcf/d)					
North America	**1,234**	1,219	1,264	**1,216**	1,311
North Sea	**8**	9	8	**10**	9
Offshore West Africa	**16**	9	21	**14**	18
	1,258	1,237	1,293	**1,240**	1,338
Total barrels of oil equivalent (boe/d)	**621,284**	649,195	574,755	**627,052**	574,688
Product mix					
Light/medium crude oil and NGLs	**18%**	18%	20%	**18%**	21%
Pelican Lake crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**15%**	14%	15%	**15%**	15%
Thermal heavy crude oil	**14%**	15%	9%	**14%**	11%
Synthetic crude oil	**13%**	15%	12%	**14%**	8%
Natural gas	**34%**	32%	38%	**33%**	39%
Percentage of gross revenue (1) (excluding midstream revenue)					
Crude oil and NGLs	**86%**	86%	83%	**84%**	77%
Natural gas	**14%**	14%	17%	**16%**	23%

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs (bbl/d)					
North America – Conventional	**220,836**	228,781	191,077	**218,625**	204,166
North America – Oil Sands Mining and Upgrading	**81,077**	96,543	64,814	**87,168**	42,439
North Sea	**27,002**	37,581	33,961	**33,760**	38,809
Offshore West Africa	**30,724**	28,225	30,551	**29,299**	29,795
	359,639	391,130	320,403	**368,852**	315,209
Natural gas (mmcf/d)					
North America	**1,213**	1,149	1,228	**1,155**	1,241
North Sea	**8**	9	8	**10**	9
Offshore West Africa	**15**	8	18	**13**	16
	1,236	1,166	1,254	**1,178**	1,266
Total barrels of oil equivalent (boe/d)	**565,595**	585,556	529,421	**565,313**	526,184

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, Pelican Lake crude oil, primary heavy crude oil, thermal heavy crude oil, and SCO.

Total crude oil and NGLs production for the nine months ended September 30, 2010 increased 19% to 420,319 bbl/d from 351,760 bbl/d for the nine months ended September 30, 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 third quarter of 2010 increased 15% to 411,585 bbl/d from 359,269 bbl/d for the third quarter of 2009, and decreased 7% from 443,045 bbl/d for the prior quarter. The increases from the comparable periods in 2009 were primarily related to the cyclic nature of the Company's thermal operations and increased Horizon production. The decrease from the prior quarter was related to an unplanned outage at Horizon, planned turnaround activities in the North Sea and the cyclic nature of the Company's thermal production. Crude oil and NGLs production in the third quarter of 2010 was slightly below the Company's previously issued guidance of 414,000 to 445,000 bbl/d.

Natural gas production for the nine months ended September 30, 2010 decreased 7% to 1,240 mmcf/d compared to 1,338 mmcf/d for the nine months ended September 30, 2009. Natural gas production for the third quarter of 2010 decreased 3% to 1,258 mmcf/d compared to 1,293 mmcf/d for the third quarter of 2009 and increased 2% from 1,237 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods in 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. The increase from the prior quarter was primarily due to the inclusion of production volumes from the acquisition of gas producing properties in the second quarter. Natural gas production in the third quarter of 2010 was within the Company's previously issued guidance of 1,247 to 1,271 mmcf/d.

For 2010, annual production guidance is targeted to average between 423,000 and 430,000 bbl/d of crude oil and NGLs and between 1,242 and 1,250 mmcf/d of natural gas. Fourth quarter 2010 production guidance is targeted to average between 432,000 and 456,000 bbl/d of crude oil and NGLs and between 1,248 and 1,273 mmcf/d of natural gas.

North America – Conventional

North America conventional crude oil and NGLs production for the nine months ended September 30, 2010 increased 12% to average 265,125 bbl/d from 236,315 bbl/d for the nine months ended September 30, 2009. For the third quarter of 2010, crude oil and NGLs production increased 20% to average 267,177 bbl/d, compared to 223,307 bbl/d for the third quarter of 2009, and decreased 3% from 275,584 bbl/d for the prior quarter. Increases in crude oil and NGLs production from comparable periods in 2009 were primarily due to the cyclic nature of the Company's thermal production and the results of a record heavy oil drilling program. The decrease from the prior quarter was related to the longer than anticipated steaming cycle in the Company's thermal production which caused volumes to be below target. Production of conventional crude oil and NGLs was slightly below the Company's previously issued guidance of 275,000 bbl/d to 285,000 bbl/d for the third quarter of 2010.

Natural gas production for the nine months ended September 30, 2010 decreased 7% to 1,216 mmcf/d from 1,311 mmcf/d for the nine months ended September 30, 2009. For the third quarter of 2010, natural gas production decreased 2% to 1,234 mmcf/d from 1,264 mmcf/d for the third quarter of 2009, and increased 1% from 1,219 mmcf/d in the prior quarter. The decreases in natural gas production from the comparable periods 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. The increase from the prior quarter was primarily due to the inclusion of production volumes from the acquisition of gas producing properties in the second quarter. Production of natural gas was within the Company's previously issued guidance of 1,225 mmcf/d to 1,245 mmcf/d for the third quarter of 2010.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 commenced production of synthetic crude oil during 2009. Production averaged 90,240 bbl/d for the nine months ended September 30, 2010, up 107% from 43,529 bbl/d for the nine months ended September 30, 2009. For the third quarter of 2010, production increased 25% to 83,809 bbl/d, compared to 66,907 bbl/d in the third quarter of 2009, and decreased 16% from 99,950 bbl/d in the prior quarter. Increases in production of synthetic crude oil from comparable periods in 2009 reflected the Company's focus on operational optimization and ramping up of production. The decrease from the prior quarter was a result of a plant-wide shutdown because of unplanned maintenance to repair localized pipe wall thinning in the amine unit. Third quarter production for 2010 was within the Company's previously issued guidance of 80,000 bbl/d to 95,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2010 decreased 13% to 33,828 bbl/d from 38,891 bbl/d for the nine months ended September 30, 2009. Third quarter 2010 North Sea crude oil production decreased 21% to 27,045 bbl/d from 34,034 bbl/d for the third quarter of 2009 and decreased 28% from 37,669 bbl/d in the prior quarter. Decreases in production volumes from the comparable periods in 2009 were due to natural field declines and timing of scheduled maintenance shut downs. The decrease in production volumes from the prior quarter was a result of planned maintenance shut downs on all of the Company's North Sea production facilities. Production in the third quarter of 2010 was at the low end of the Company's previously issued guidance of 27,000 bbl/d to 30,000 bbl/d.

Offshore West Africa

Offshore West Africa crude oil production decreased 6% to 31,126 bbl/d for the nine months ended September 30, 2010 from 33,025 bbl/d for the nine months ended September 30, 2009. Third quarter crude oil production decreased 4% to 33,554 bbl/d from 35,021 bbl/d for the third quarter of 2009, and increased 12% from 29,842 bbl/d in the prior quarter. Final commissioning of Platform B at the Olowi Field was completed in the second quarter of 2010 and first crude oil production was achieved as planned in April. The planned shutdown at Espoir in the prior quarter for the completion of installation of facilities upgrades resulted in increased volumes in the current quarter. Production in the third quarter of 2010 was within the Company's previously issued guidance of 32,000 bbl/d to 35,000 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 offtake vessels, as follows:

(bbl)	**Sep 30 2010**	Jun 30 2010	Dec 31 2009
North America – Conventional	**761,351**	761,351	1,131,372
North America – Oil Sands Mining and Upgrading (SCO)	**1,045,281**	1,139,778	1,224,481
North Sea	**793,582**	1,018,357	713,112
Offshore West Africa	**918,535**	1,428,949	51,103
	3,518,749	4,348,435	3,120,068

OPERATING HIGHLIGHTS – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 63.21**	$ 63.62	$ 62.90	**$ 65.10**	$ 54.17
Royalties	**9.05**	8.95	7.89	**9.34**	6.31
Production expense	**15.37**	13.19	16.71	**14.38**	16.08
Netback	**$ 38.79**	$ 41.48	$ 38.30	**$ 41.38**	$ 31.78
Natural gas ($/mcf) [1]					
Sales price [2]	**$ 3.75**	$ 3.86	$ 3.80	**$ 4.26**	$ 4.46
Royalties [3]	**0.11**	0.25	0.13	**0.25**	0.31
Production expense	**1.05**	1.05	1.05	**1.10**	1.09
Netback	**$ 2.59**	$ 2.56	$ 2.62	**$ 2.91**	$ 3.06
Barrels of oil equivalent ($/boe) [1]					
Sales price [2]	**$ 47.44**	$ 47.97	$ 45.52	**$ 49.68**	$ 42.54
Royalties	**5.83**	6.10	4.85	**6.32**	4.43
Production expense	**11.89**	10.55	12.26	**11.37**	12.07
Netback	**$ 29.72**	$ 31.32	$ 28.41	**$ 31.99**	$ 26.04

(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 – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 59.13**	$ 60.35	$ 60.07	**$ 61.79**	$ 51.36
North Sea	**$ 81.47**	$ 79.30	$ 75.91	**$ 80.40**	$ 65.16
Offshore West Africa	**$ 77.32**	$ 79.21	$ 70.05	**$ 78.34**	$ 61.92
Company average	**$ 63.21**	$ 63.62	$ 62.90	**$ 65.10**	$ 54.17
Natural gas ($/mcf) (1) (2)					
North America	**$ 3.70**	$ 3.85	$ 3.76	**$ 4.23**	$ 4.44
North Sea	**$ 4.52**	$ 3.33	$ 5.70	**$ 4.08**	$ 4.53
Offshore West Africa	**$ 7.36**	$ 5.14	$ 5.72	**$ 6.17**	$ 6.54
Company average	**$ 3.75**	$ 3.86	$ 3.80	**$ 4.26**	$ 4.46
Company average ($/boe) (1) (2)	**$ 47.44**	$ 47.97	$ 45.52	**$ 49.68**	$ 42.54

(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 20% to average $61.79 per bbl for the nine months ended September 30, 2010 from $51.36 per bbl for the nine months ended September 30, 2009. Realized crude oil prices averaged $59.13 per bbl for the third quarter of 2010 and decreased 2% compared to $60.07 per bbl for the third quarter of 2009 and $60.35 per bbl for the prior quarter. The increase from the comparable nine-month period in 2009 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 prices from the prior quarter was a result of lower WTI benchmark pricing and the widening Heavy differential.

The Company continues to focus on its crude oil marketing strategy, and in the third quarter of 2010 contributed approximately 153,000 bbl/d of heavy crude oil blends to the WCS stream.

In the first quarter of 2010, the Company announced, together with North West Upgrading Inc., the submission of a joint proposal to the Government of Alberta to construct and operate a bitumen refinery near Redwater, Alberta under the Alberta Royalty Framework's Bitumen Royalty In Kind ("BRIK") program. In the second quarter, the Government of Alberta announced that the proposal had been selected for exclusive negotiations following a comprehensive review. Further project development is dependent upon successful completion of these negotiations on commercially acceptable terms and final project sanction by the respective parties.

North America realized natural gas prices decreased 5% to average $4.23 per mcf for the nine months ended September 30, 2010 from $4.44 per mcf for the nine months ended September 30, 2009. The decrease in natural gas prices from the comparable period in 2009 was primarily related to the impact of the natural gas physical sales contracts in 2009, the widening NYMEX and AECO differential and the impact of a stronger Canadian dollar relative to the US dollar. Realized natural gas prices averaged $3.70 per mcf for the third quarter of 2010, a decrease of 2% compared to $3.76 per mcf for the third quarter of 2009 and a decrease of 4% from $3.85 per mcf for the prior quarter. The slight decrease in realized natural gas prices from the comparative periods in 2009 was primarily related to weak benchmark prices due to lower demand and high storage levels, and the impact of the 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, partially offset by higher demand resulting from the power and industrial sectors and weather patterns in the Northeast part of the United States.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

(Quarterly Average)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs ($/bbl)	**$ 62.40**	$ 68.13	$ 59.24
Pelican Lake crude oil ($/bbl)	**$ 58.44**	$ 60.38	$ 61.11
Primary heavy crude oil ($/bbl)	**$ 58.97**	$ 60.26	$ 60.42
Thermal heavy crude oil ($/bbl)	**$ 57.60**	$ 56.53	$ 59.52
Natural gas ($/mcf)	**$ 3.70**	$ 3.85	$ 3.76

(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 23% to average $80.40 per bbl for the nine months ended September 30, 2010 from $65.16 per bbl for the nine months ended September 30, 2009. Realized crude oil prices increased 7% to average $81.47 per bbl for the third quarter of 2010 from $75.91 per bbl for the third quarter of 2009, and increased 3% from $79.30 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 27% to average $78.34 per bbl for the nine months ended September 30, 2010 from $61.92 per bbl for the nine months ended September 30, 2009. Realized crude oil prices increased 10% to average $77.32 per bbl for the third quarter of 2010 from $70.05 per bbl for the third quarter of 2009, and decreased 2% from $79.21 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. Realized crude oil prices in Offshore West Africa were also impacted by quality differences and the timing of liftings from each field.

ROYALTIES – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 10.40**	$ 10.42	$ 8.80	**$ 10.96**	$ 7.30
North Sea	**$ 0.13**	$ 0.18	$ 0.16	**$ 0.16**	$ 0.13
Offshore West Africa	**$ 6.52**	$ 4.29	$ 8.94	**$ 4.95**	$ 6.03
Company average	**$ 9.05**	$ 8.95	$ 7.89	**$ 9.34**	$ 6.31
Natural gas ($/mcf) (1)					
North America (2)	**$ 0.10**	$ 0.25	$ 0.12	**$ 0.25**	$ 0.30
Offshore West Africa	**$ 0.85**	$ 0.26	$ 0.74	**$ 0.46**	$ 0.64
Company average	**$ 0.11**	$ 0.25	$ 0.13	**$ 0.25**	$ 0.31
Company average ($/boe) (1)	**$ 5.83**	$ 6.10	$ 4.85	**$ 6.32**	$ 4.43
Percentage of revenue (3)					
Crude oil and NGLs	**14%**	14%	13%	**14%**	12%
Natural gas (2)	**3%**	6%	3%	**6%**	7%
Boe	**12%**	13%	11%	**13%**	10%

(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 nine months ended September 30, 2010 compared to the nine months ended September 30, 2009 reflect stronger benchmark commodity prices and the impact of the changes under the Alberta Royalty Framework.

Crude oil and NGLs royalties averaged approximately 18% of revenues for the third quarter of 2010, compared to 15% for the third quarter in 2009 and 17% for the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of gross revenue for 2010.

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

Offshore West Africa

Under the terms of the 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 9% for the third quarter of 2010 compared to 13% for the third quarter of 2009 and 5% for the prior quarter. Offshore West Africa royalty rates are anticipated to average 6% to 8% of gross revenue for 2010.

PRODUCTION EXPENSE – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.41**	$ 11.75	$ 15.19	**$ 12.40**	$ 15.01
North Sea	**$ 44.45**	$ 21.35	$ 31.30	**$ 29.61**	$ 26.96
Offshore West Africa	**$ 13.66**	$ 18.33	$ 13.35	**$ 14.95**	$ 11.76
Company average	**$ 15.37**	$ 13.19	$ 16.71	**$ 14.38**	$ 16.08
Natural gas ($/mcf) [1]					
North America	**$ 1.04**	$ 1.03	$ 1.04	**$ 1.08**	$ 1.08
North Sea	**$ 2.42**	$ 2.53	$ 1.57	**$ 2.97**	$ 1.69
Offshore West Africa	**$ 1.69**	$ 1.64	$ 1.37	**$ 1.65**	$ 1.44
Company average	**$ 1.05**	$ 1.05	$ 1.05	**$ 1.10**	$ 1.09
Company average ($/boe) [1]	**$ 11.89**	$ 10.55	$ 12.26	**$ 11.37**	$ 12.07

(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 nine months ended September 30, 2010 decreased 17% to $12.40 per bbl from $15.01 per bbl for the nine months ended September 30, 2009. Production expense for the third quarter of 2010 decreased 18% to $12.41 per bbl from $15.19 per bbl for the third quarter of 2009 and increased 6% from $11.75 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 increase 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 2010.

North America natural gas production expense for the nine months ended September 30, 2010 averaged $1.08 per mcf and was comparable to the nine months ended September 30, 2009. Production expense for the third quarter of 2010 averaged $1.04 per mcf and was comparable to the third quarter of 2009 and the prior quarter. North America natural gas production expense is anticipated to average $1.05 to $1.10 per mcf for 2010.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2010 increased 10% to $29.61 per bbl from $26.96 per bbl for the nine months ended September 30, 2009. Production expense for the third quarter of 2010 increased 42% to $44.45 per bbl from $31.30 per bbl for the third quarter of 2009 and 108% from $21.35 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 as a result of planned facility maintenance shutdowns in the third quarter of 2010. Production expense increased on a per barrel basis from the prior quarter due to higher maintenance costs and lower production volumes associated with the planned facility maintenance shutdowns, and one-time third party cost recoveries in the prior quarter. Production expense is anticipated to average $30.00 to $31.00 per bbl for 2010.

Offshore West Africa

Offshore West Africa crude oil production expense increased 27% to $14.95 per bbl from $11.76 per bbl for the nine months ended September 30, 2009. Production expense for the third quarter of 2010 increased 2% to $13.66 per bbl from $13.35 per bbl for the third quarter of 2009 and decreased 25% from $18.33 per bbl for the prior quarter. Production expense increased on a per barrel basis from the comparable periods in the prior year 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 decreased from the prior quarter due to a higher proportion of liftings from the Espoir Field. Production expense is anticipated to average $14.50 to $15.50 per bbl for 2010.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Expense ($ millions)	**$ 763**	$ 740	$ 610	**$ 2,182**	$ 1,902
$/boe (1)	**$ 15.22**	$ 15.85	$ 12.64	**$ 14.95**	$ 13.14

(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 the prior year 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 increased liftings from the Olowi Field. The increase in depletion, depreciation and amortization expense from the prior quarter was primarily due to higher liftings in Offshore West Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Expense ($ millions)	**$ 22**	$ 21	$ 17	**$ 63**	$ 52
$/boe (1)	**$ 0.43**	$ 0.45	$ 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.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
SCO sales price (2)	**$ 75.31**	$ 75.97	$ 69.11	**$ 76.66**	$ 67.65
Bitumen value for royalty purposes (3)	**$ 54.13**	$ 52.67	$ 56.79	**$ 56.04**	$ 55.40
Bitumen royalties (4)	**$ 2.57**	$ 2.69	$ 2.19	**$ 2.70**	$ 1.63

(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.

The increase in SCO prices from the comparative periods in 2009 was primarily due to the increase in the WTI benchmark price, offset by the impact of the strengthening Canadian dollar. The decrease in the SCO price for the third quarter of 2010 compared to the prior quarter was primarily due to weakening in WTI pricing. 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			Nine Months Ended	
($ millions)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Cash costs, excluding natural gas costs	**$ 243**	$ 262	$ 212	**$ 804**	$ 371
Natural gas costs	**25**	28	30	**100**	53
Total cash production costs	**$ 268**	$ 290	$ 242	**$ 904**	$ 424

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Cash costs, excluding natural gas costs	**$ 31.20**	$ 29.09	$ 32.36	**$ 32.40**	$ 34.24
Natural gas costs	**3.15**	3.18	4.49	**4.03**	4.89
Total cash production costs	**$ 34.35**	$ 32.27	$ 36.85	**$ 36.43**	$ 39.13
Sales (bbl/d)	**84,836**	98,645	71,578	**90,896**	39,736

(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 $36.43 per bbl for the nine months ended September 30, 2010 compared to $39.13 per bbl for the nine months ended September 30, 2009. Total cash production costs averaged $34.35 per bbl in the third quarter of 2010 compared to $36.85 per bbl for the third quarter of 2009, and $32.27 in the prior quarter. The decrease in cash production costs from the comparative periods in 2009 was primarily due to the Company's ongoing focus on planned maintenance, operational optimization 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 lower August production volumes resulting from the plant-wide shutdown for unplanned maintenance to repair localized pipe wall thinning. Annual production guidance targets were revised to average between 90,000 and 93,000 bbl/d to reflect the impact of this outage.

As production volumes continue to stabilize throughout the remainder of 2010, cash production costs are expected to be between $33.00 to $37.00 per bbl for 2010.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Depletion, depreciation and amortization	**$ 86**	$ 94	$ 66	**$ 270**	$ 104
Asset retirement obligation accretion	**6**	5	7	**17**	15
Total	**$ 92**	$ 99	$ 73	**$ 287**	$ 119

($/bbl) [1]	Three Months Ended Sep 30 2010	Jun 30 2010	Sep 30 2009	Nine Months Ended Sep 30 2010	Sep 30 2009
Depletion, depreciation and amortization	**$ 10.96**	$ 10.47	$ 9.99	**$ 10.87**	$ 9.61
Asset retirement obligation accretion	**0.71**	0.62	0.95	**0.67**	1.35
Total	**$ 11.67**	$ 11.09	$ 10.94	**$ 11.54**	$ 10.96

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

Depletion, depreciation and amortization increased from the comparable periods in 2009, primarily due to the impact of depreciation determined on a straight-line basis.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2010	Jun 30 2010	Sep 30 2009	Nine Months Ended Sep 30 2010	Sep 30 2009
Revenue	**$ 19**	$ 21	$ 18	**$ 59**	$ 54
Production expense	**4**	7	4	**16**	14
Midstream cash flow	**15**	14	14	**43**	40
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 13**	$ 12	$ 12	**$ 37**	$ 34

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended Sep 30 2010	Jun 30 2010	Sep 30 2009	Nine Months Ended Sep 30 2010	Sep 30 2009
Expense ($ millions)	**$ 43**	$ 60	$ 38	**$ 157**	$ 132
$/boe [1]	**$ 0.73**	$ 1.03	$ 0.72	**$ 0.92**	$ 0.85

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

Administration expense for the nine and three months ended September 30, 2010 increased from the comparative periods in 2009 due to higher staffing related costs. Administrative expense for the third quarter of 2010 decreased compared to the prior quarter, due to lower staffing costs and increased recoveries on a higher capital program.

STOCK-BASED COMPENSATION EXPENSE

($ millions)	Three Months Ended Sep 30 2010	Three Months Ended Jun 30 2010	Three Months Ended Sep 30 2009	Nine Months Ended Sep 30 2010	Nine Months Ended Sep 30 2009
Expense (recovery)	**$ 18**	$ (58)	$ 172	**$ (42)**	$ 268

The Company recorded a $42 million ($42 million after-tax) stock-based compensation recovery for the nine months ended September 30, 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 6% decrease in the Company's share price (Company's share price as at: September 30, 2010 - $35.59; June 30, 2010 – $35.33; December 31, 2009 – $38.00; September 30, 2009 – $36.15). For the nine months ended September 30, 2010, the Company capitalized $3 million in stock-based compensation to Oil Sands Mining and Upgrading (September 30, 2009 – $2 million recovery). 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 September 30, 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 recently proposed 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 nine months ended September 30, 2010, the Company paid $39 million for stock options surrendered for cash settlement (September 30, 2009 – $79 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Sep 30 2010	Three Months Ended Jun 30 2010	Three Months Ended Sep 30 2009	Nine Months Ended Sep 30 2010	Nine Months Ended Sep 30 2009
Expense, gross	**$ 116**	$ 114	$ 124	**$ 348**	$ 397
Less: capitalized interest, Oil Sands Mining and Upgrading	**7**	5	6	**19**	98
Expense, net	**$ 109**	$ 109	$ 118	**$ 329**	$ 299
$/boe [1]	**$ 1.89**	$ 1.88	$ 2.23	**$ 1.93**	$ 1.92
Average effective interest rate	**4.9%**	4.8%	4.3%	**4.8%**	4.2%

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

Gross interest expense decreased from the comparable periods in 2009 primarily due to the impact of fluctuations in foreign exchange rates on US dollar denominated debt and lower variable interest rates and debt levels. The Company's average effective interest rate increased from the comparable periods in 2009 primarily due to an increased weighting of fixed versus floating rate debt, partially offset by lower 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.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Crude oil and NGLs financial instruments	**$ 5**	$ 15	$ (235)	**$ 37**	$ (1,182)
Natural gas financial instruments	**(85)**	(78)	–	**(181)**	(33)
Foreign currency contracts and interest rate swaps	**10**	(28)	35	**22**	84
Realized gain	**$ (70)**	$ (91)	$ (200)	**$ (122)**	$ (1,131)
Crude oil and NGLs financial instruments	**$ 8**	$ (151)	$ 208	**$ (216)**	$ 1,711
Natural gas financial instruments	**56**	94	(4)	**20**	(41)
Foreign currency contracts and interest rate swaps	**28**	(25)	70	**(2)**	13
Unrealized loss (gain)	**$ 92**	$ (82)	$ 274	**$ (198)**	$ 1,683
Net loss (gain)	**$ 22**	$ (173)	$ 74	**$ (320)**	$ 552

Complete details related to outstanding derivative financial instruments at September 30, 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 $198 million ($147 million after-tax) on its risk management activities for the nine months ended September 30, 2010, including a $92 million ($71 million after-tax) net unrealized loss for the third quarter of 2010 (June 30, 2010 – unrealized gain of $82 million, $64 million after-tax; September 30, 2009 – unrealized loss of $274 million, $217 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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2010**	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Net realized loss (gain)	**$ 11**	$ (9)	$ (33)	**$ (8)**	$ 26
Net unrealized (gain) loss (1)	**(75)**	165	(391)	**(60)**	(573)
Net (gain) loss	**$ (64)**	$ 156	$ (424)	**$ (68)**	$ (547)

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

The net unrealized foreign exchange gain for the nine months ended September 30, 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 September 30, 2010 – unrealized loss of $62 million, June 30, 2010 – unrealized gain of $91 million, September 30, 2009 – unrealized loss of $172 million; nine months ended September 30, 2010 – unrealized loss of $30 million, September 30, 2009 – unrealized loss of $290 million). The net realized foreign exchange gain for the nine months ended September 30, 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 third quarter at US$0.9711 (June 30, 2010 – US$0.9429; December 31, 2009 – US$0.9555; September 30, 2009 – US$0.9327).

TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2010	Jun 30 2010	Sep 30 2009	Nine Months Ended Sep 30 2010	Sep 30 2009
Current	**$ 10**	$ 29	$ 10	**$ 71**	$ 66
Deferred	**11**	5	13	**23**	8
Taxes other than income tax	**$ 21**	$ 34	$ 23	**$ 94**	$ 74
North America (1)	**$ 115**	$ 139	$ 7	**$ 383**	$ 17
North Sea	**23**	43	55	**119**	218
Offshore West Africa	**25**	9	28	**40**	59
Current income tax	**163**	191	90	**542**	294
Future income tax expense (recovery)	**40**	71	83	**306**	(174)
	203	262	173	**848**	120
Income tax rate and other legislative changes (2)	**–**	–	–	**(83)**	19
	$ 203	$ 262	$ 173	**$ 765**	$ 139
Effective income tax rate on adjusted net earnings from operations	**25.9%**	27.9%	25.7%	**26.6%**	22.9%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) 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 proposed changes, the Company anticipates that Canadian based employees will no longer surrender their options for cash payments, resulting in a loss of 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 include the effect of a recovery of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted.

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 conventional crude oil and natural gas 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 2010, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense of $450 million to $500 million in Canada and $230 million to $250 million in the North Sea and Offshore West Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2010	Three Months Ended Jun 30 2010	Three Months Ended Sep 30 2009	Nine Months Ended Sep 30 2010	Nine Months Ended Sep 30 2009
Expenditures on property, plant and equipment					
Net property acquisitions (dispositions)	**$ 51**	$ 949	$ (30)	**$ 1,036**	$ (5)
Land acquisition and retention	**27**	37	18	**102**	49
Seismic evaluations	**29**	19	21	**81**	60
Well drilling, completion and equipping	**365**	249	261	**1,056**	953
Production and related facilities	**253**	176	235	**811**	755
Total net reserve replacement expenditures	**725**	1,430	505	**3,086**	1,812
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	**92**	56	21	**219**	62
Capitalized interest, stock-based compensation and other	**10**	39	11	**58**	86
Sustaining capital	**35**	27	23	**80**	27
Total Oil Sands Mining and Upgrading [2]	**137**	122	55	**357**	446
Midstream	**3**	1	–	**4**	5
Abandonments [3]	**45**	15	12	**99**	31
Head office	**4**	5	2	**13**	9
Total net capital expenditures	**$ 914**	$ 1,573	$ 574	**$ 3,559**	$ 2,303
By segment					
North America	**$ 610**	$ 1,350	$ 358	**$ 2,769**	$ 1,227
North Sea	**59**	29	38	**111**	120
Offshore West Africa	**55**	50	108	**204**	464
Other	**1**	1	1	**2**	1
Oil Sands Mining and Upgrading	**137**	122	55	**357**	446
Midstream	**3**	1	–	**4**	5
Abandonments [3]	**45**	15	12	**99**	31
Head office	**4**	5	2	**13**	9
Total	**$ 914**	$ 1,573	$ 574	**$ 3,559**	$ 2,303

(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 nine months ended September 30, 2010 were $3,559 million compared to $2,303 million for the nine months ended September 30, 2009. The increase in capital expenditures from the comparable periods in 2009 was primarily the result of the purchase of crude oil and natural gas producing properties and undeveloped land in the Company's core regions in Western Canada. Net capital expenditures for the third quarter of 2010 were $914 million compared to $574 million for the third quarter of 2009 and $1,573 million in the prior quarter. The decrease in capital expenditures in the current quarter was due to reduced property acquisitions compared to the prior quarter.

Drilling Activity (number of wells)

	Three Months Ended			Nine Months Ended	
	Sep 30 2010	Jun 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Net successful natural gas wells	**19**	10	17	**74**	81
Net successful crude oil wells	**281**	92	262	**616**	449
Dry wells	**9**	2	10	**25**	29
Stratigraphic test / service wells	**14**	9	6	**320**	249
Total	**323**	113	295	**1,035**	808
Success rate (excluding stratigraphic test / service wells)	**97%**	98%	97%	**97%**	95%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 81% of the total capital expenditures for the nine months ended September 30, 2010 compared to approximately 55% for the nine months ended September 30, 2009.

During the third quarter of 2010, the Company targeted 19 net natural gas wells, including 4 wells in Northeast British Columbia, 12 wells in Northwest Alberta, 1 well in the Northern Plains region and 2 wells in the Southern Plains region. The Company also targeted 289 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 209 heavy crude oil wells, 39 Pelican Lake crude oil wells, 6 thermal crude oil wells and 3 light crude oil wells were drilled. Another 32 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 third quarter of 2010 averaged approximately 85,000 bbl/d, compared to approximately 52,000 bbl/d for the third quarter of 2009 and approximately 96,000 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 has received approval from regulators to commence steaming on the next cycle.

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. Subsequent to September 30, 2010 the Company's Board of Directors sanctioned Kirby Phase 1. Construction is targeted to commence 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 third quarter of 2010. Drilling included 39 horizontal wells in the third 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 third quarter of 2010, compared to approximately 37,000 bbl/d for the third quarter of 2009 and the prior quarter.

For the fourth quarter of 2010, the Company's overall planned drilling activity in North America is expected to be comprised of 20 net natural gas wells and 351 net crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

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

North Sea

In the third quarter of 2010, the Company continued drilling on the Ninian South Platform, with 0.9 net injection wells drilled in the quarter. The Company continues to focus on developing and high grading its inventory of drilling locations for future execution.

Offshore West Africa

During the third quarter of 2010, the final well on Platform B at the Olowi Field was completed and drilling commenced on Platform A. Drilling continued with 0.9 net crude oil wells completed during the quarter. The Company achieved first crude oil production at Platform A in the fourth quarter of 2010.

At Espoir the facilities upgrades were completed during the second quarter. The associated production uplift from the upgrades is now anticipated in the fourth quarter of 2010.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2010**	Jun 30 2010	Dec 31 2009	Sep 30 2009
Working capital (deficit) (1)	**$ (515)**	$ (245)	$ (514)	$ (396)
Long-term debt (2)	**$ 8,490**	$ 9,335	$ 9,658	$ 10,557
Share capital	**$ 3,015**	$ 3,006	$ 2,834	$ 2,827
Retained earnings	**18,502**	18,066	16,696	16,299
Accumulated other comprehensive (loss) income	**(97)**	(13)	(104)	(61)
Shareholders' equity	**$ 21,420**	$ 21,059	$ 19,426	$ 19,065
Debt to book capitalization (2) (3)	**28%**	31%	33%	36%
Debt to market capitalization (2) (4)	**18%**	20%	19%	21%
After tax return on average common shareholders' equity (5)	**13%**	13%	8%	16%
After tax return on average capital employed (2) (6)	**10%**	10%	6%	10%

(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 September 30, 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.

At September 30, 2010, the Company had $3,067 million of available credit under its bank credit facilities.

Long-term debt was $8,490 million at September 30, 2010, resulting in a debt to book capitalization ratio of 28% (June 30, 2010 – 31%; December 31, 2009 – 33%; September 30, 2009 – 36%). 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 and natural gas production for 2010 and 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 September 30, 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 September 30, 2010, in accordance with the policy, approximately 32% of budgeted crude oil volumes and approximately 18% of budgeted natural gas volumes were hedged using collars for the remainder of 2010, and approximately 5% of budgeted crude oil volumes were hedged using collars for 2011. Subsequent to September 30, 2010, the Company entered into 100,000 bbl/d of US$70 WTI put options for the period January to December 2011 for a total cost of US$106 million, and 27,000 bbl/d of US$70 – US$102.14 WTI collars for the period January to December 2011.

Further details related to the Company's commodity related derivative financial instruments outstanding at September 30, 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 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 September 30, 2010, there were 1,087,651,000 common shares outstanding and 58,034,000 stock options outstanding. As at November 2, 2010, the Company had 1,088,133,000 common shares outstanding and 57,207,000 stock options outstanding.

In March 2010, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.30 per common share for 2010. The increase represented a 43% increase from 2009, 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 November 2, 2010, 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 September 30, 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 September 30, 2010:

($ millions)	Remaining 2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 58	$ 220	$ 193	$ 167	$ 163	$ 1,085
Offshore equipment operating leases	$ 42	$ 135	$ 102	$ 100	$ 101	$ 258
Offshore drilling	$ 11	$ 8	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 4	$ 24	$ 21	$ 31	$ 39	$ 6,537
Long-term debt (2)	$ 400	$ 412	$ 360	$ 812	$ 360	$ 5,344
Interest expense (3)	$ 89	$ 442	$ 406	$ 364	$ 344	$ 4,691
Office leases	$ 7	$ 27	$ 28	$ 29	$ 29	$ 391
Other	$ 87	$ 74	$ 28	$ 18	$ 16	$ 38

(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 2010 – 2014 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 $814 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 September 30, 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.

For the impact of new accounting standards, refer to note 2 of the unaudited interim consolidated financial statements as at September 30, 2010.

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 has been 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 completed the Diagnostic and Planning phases (Phases 1 and 2). 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. The Company is finalizing the necessary research to develop and document IFRS policies to address the major differences noted (Phase 3). A summary of the significant differences identified is included below. As certain IFRS standards are expected to change prior to adoption in 2011, the Company will continue to update its IFRS conversion project to recognize new and amended accounting standards.

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 (Phase 4), including 2010 requirements to capture both Canadian GAAP and IFRS data. IT system changes are substantially 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 follows the full cost method of accounting for its conventional crude oil and natural gas 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 will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to PP&E. If technically feasible and commercially viable reserves are not established for a new area, the costs must be 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 will be 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 will be 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 intends to adopt 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 expected 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 expected increase will be 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 intends to utilize 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 expected 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 and 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 will be 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 expected 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 will 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 expected decrease in the net future income tax liability must be recorded in retained earnings.

Other IFRS 1 Exemptions

The Company also intends to adopt the following IFRS 1 transition exemptions:

- The Company intends to elect to reset the foreign currency translation adjustment to zero by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.

- The Company intends to adopt 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 will decrease by less than 4% compared to the balance previously determined under Canadian GAAP, resulting in a marginal increase in the Company's debt to book capitalization to 34% from 33%. 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 be revised prior to the final release of the Company's January 1, 2010 transitional balance sheet.

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 third 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	$ 129	$ 0.12	$ 99	$ 0.09
Including financial derivatives	$ 125	$ 0.11	$ 96	$ 0.09
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 35	$ 0.03	$ 26	$ 0.02
Including financial derivatives	$ 36	$ 0.03	$ 27	$ 0.02
Volume changes				
Crude oil – 10,000 bbl/d	$ 166	$ 0.15	$ 95	$ 0.09
Natural gas – 10 mmcf/d	$ 9	$ 0.01	$ –	$ –
Foreign currency rate change				
$0.01 change in US$ (1)				
Including financial derivatives	$ 99 – 101	$ 0.09	$ 35 – 36	$ 0.03
Interest rate change – **1%**	$ 5	$ 0.01	$ 5	$ 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)	**Sep 30 2010**	Dec 31 2009
ASSETS		
Current assets		
Cash and cash equivalents	**$ 27**	$ 13
Accounts receivable	**1,246**	1,148
Inventory, prepaids and other	**582**	584
Future income tax	**5**	146
	1,860	1,891
Property, plant and equipment (note 13)	**40,035**	39,115
Other long-term assets (note 3)	**30**	18
	$ 41,925	$ 41,024
LIABILITIES		
Current liabilities		
Accounts payable	**$ 274**	$ 240
Accrued liabilities	**1,891**	1,522
Current portion of other long-term liabilities (note 5)	**210**	643
	2,375	2,405
Long-term debt (note 4)	**8,490**	9,658
Other long-term liabilities (note 5)	**1,817**	1,848
Future income tax	**7,823**	7,687
	20,505	21,598
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**3,015**	2,834
Retained earnings	**18,502**	16,696
Accumulated other comprehensive loss (note 8)	**(97)**	(104)
	21,420	19,426
	$ 41,925	$ 41,024

Commitments (note 12)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended Sep 30 2010	Three Months Ended Sep 30 2009	Nine Months Ended Sep 30 2010	Nine Months Ended Sep 30 2009
Revenue	**$ 3,341**	$ 2,823	**$ 10,535**	$ 7,759
Less: royalties	**(313)**	(240)	**(990)**	(651)
Revenue, net of royalties	**3,028**	2,583	**9,545**	7,108
Expenses				
Production	**867**	813	**2,573**	2,168
Transportation and blending	**350**	241	**1,323**	867
Depletion, depreciation and amortization	**851**	673	**2,458**	1,983
Asset retirement obligation accretion (note 5)	**28**	24	**80**	67
Administration	**43**	38	**157**	132
Stock-based compensation expense (recovery) (note 5)	**18**	172	**(42)**	268
Interest, net	**109**	118	**329**	299
Risk management activities (note 11)	**22**	74	**(320)**	552
Foreign exchange gain	**(64)**	(424)	**(68)**	(547)
	2,224	1,729	**6,490**	5,789
Earnings before taxes	**804**	854	**3,055**	1,319
Taxes other than income tax	**21**	23	**94**	74
Current income tax expense (note 6)	**163**	90	**542**	294
Future income tax expense (recovery) (note 6)	**40**	83	**306**	(174)
Net earnings	**$ 580**	$ 658	**$ 2,113**	$ 1,125
Net earnings per common share (note 10)				
Basic and diluted	**$ 0.53**	$ 0.61	**$ 1.94**	$ 1.04

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Nine Months Ended **Sep 30 2010**	Sep 30 2009
Share capital (note 7)		
Balance – beginning of period	**$ 2,834**	$ 2,768
Issued upon exercise of stock options	**83**	21
Previously recognized liability on stock options exercised for common shares	**104**	38
Purchase of common shares under Normal Course Issuer Bid	**(6)**	–
Balance – end of period	**3,015**	2,827
Retained earnings		
Balance – beginning of period	**16,696**	15,344
Net earnings	**2,113**	1,125
Purchase of common shares under Normal Course Issuer Bid (note 7)	**(62)**	–
Dividends on common shares (note 7)	**(245)**	(170)
Balance – end of period	**18,502**	16,299
Accumulated other comprehensive (loss) income (note 8)		
Balance – beginning of period	**(104)**	262
Other comprehensive income (loss), net of taxes	**7**	(323)
Balance – end of period	**(97)**	(61)
Shareholders' equity	**$ 21,420**	$ 19,065

Consolidated Statements of Comprehensive Income

	Three Months Ended		Nine Months Ended	
(millions of Canadian dollars, unaudited)	**Sep 30 2010**	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Net earnings	**$ 580**	$ 658	**$ 2,113**	$ 1,125
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) gain during the period, net of taxes of $17 million (2009 – $nil) – three months ended; $5 million (2009 – $4 million) – nine months ended	**(62)**	6	**22**	(24)
Reclassification to net earnings, net of taxes of $nil (2009 – $nil) – three months ended; $1 million (2009 – $1 million) – nine months ended	**(1)**	(2)	**(4)**	(10)
	(63)	4	**18**	(34)
Foreign currency translation adjustment				
Translation of net investment	**(21)**	(140)	**(11)**	(289)
Other comprehensive (loss) income, net of taxes	**(84)**	(136)	**7**	(323)
Comprehensive income	**$ 496**	$ 522	**$ 2,120**	$ 802

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2010**	Three Months Ended Sep 30 2009	Nine Months Ended **Sep 30 2010**	Nine Months Ended Sep 30 2009
Operating activities				
Net earnings	**$ 580**	$ 658	**$ 2,113**	$ 1,125
Non-cash items				
Depletion, depreciation and amortization	**851**	673	**2,458**	1,983
Asset retirement obligation accretion	**28**	24	**80**	67
Stock-based compensation expense (recovery)	**18**	172	**(42)**	268
Unrealized risk management loss (gain)	**92**	274	**(198)**	1,683
Unrealized foreign exchange gain	**(75)**	(391)	**(60)**	(573)
Deferred petroleum revenue tax expense	**11**	13	**23**	8
Future income tax expense (recovery)	**40**	83	**306**	(174)
Other	**4**	8	**(12)**	2
Abandonment expenditures	**(45)**	(12)	**(99)**	(31)
Net change in non-cash working capital	**117**	58	**212**	(55)
	1,621	1,560	**4,781**	4,303
Financing activities				
Repayment of bank credit facilities, net	**(651)**	(798)	**(1,094)**	(1,304)
Repayment of senior unsecured notes	**–**	–	**–**	(34)
Issue of common shares on exercise of stock options	**9**	3	**83**	21
Purchase of common shares under Normal Course Issuer Bid	**(68)**	–	**(68)**	–
Dividends on common shares	**(82)**	(57)	**(220)**	(168)
Net change in non-cash working capital	**(37)**	(44)	**(36)**	(48)
	(829)	(896)	**(1,335)**	(1,533)
Investing activities				
Expenditures on property, plant, and equipment	**(869)**	(588)	**(3,463)**	(2,305)
Net proceeds on sale of property, plant and equipment	**–**	26	**3**	33
Net expenditures on property, plant and equipment	**(869)**	(562)	**(3,460)**	(2,272)
Net change in non-cash working capital	**85**	(113)	**28**	(511)
	(784)	(675)	**(3,432)**	(2,783)
Increase (decrease) in cash and cash equivalents	**8**	(11)	**14**	(13)
Cash and cash equivalents – beginning of period	**19**	25	**13**	27
Cash and cash equivalents – end of period	**$ 27**	$ 14	**$ 27**	$ 14
Interest paid	**$ 150**	$ 157	**$ 382**	$ 433
Taxes paid				
Taxes other than income tax	**$ 75**	$ 34	**$ 69**	$ 34
Current income tax	**$ 33**	$ 87	**$ 45**	$ 128

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. The Company has assessed those accounting policies that will be affected by the change to IFRS and continues to assess the potential impact of these changes on its financial position and results of operations.

Recently issued accounting standards under Canadian GAAP

The following standards will be effective for the Company's year beginning on January 1, 2011:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

Section 1582 – "Business Combinations", 1601 – "Consolidated Financial Statements", and 1602 – "Non-Controlling Interests" replace Section 1581 – "Business Combinations", and 1600 – "Consolidated Financial Statements". The new standards are the Canadian equivalent of IFRS 3 "Business Combinations" and IAS 27 "Consolidated and Separate Financial Statements". Section 1582 is effective for business combinations for acquisition dates on or after January 1, 2011. Earlier adoption is permitted, provided all three new standards are adopted simultaneously. Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at fair value at the acquisition date, rather than the date when the acquisition was agreed to and announced. In addition, most acquisition costs are expensed as incurred, instead of being included in the purchase consideration. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts. Section 1601 carries forward existing guidance on the preparation of consolidated financial statements, other than non-controlling interests. Section 1602 provides guidance on the treatment of non-controlling interests after acquisition.

3. OTHER LONG–TERM ASSETS

	Sep 30 2010	Dec 31 2009
Other	$ 30	$ 18

4. LONG–TERM DEBT

	Sep 30 2010	Dec 31 2009
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	$ 814	$ 1,897
Medium-term notes	1,200	1,200
	2,014	3,097
US dollar denominated debt		
US dollar debt securities (2010 and 2009 – US$6,300 million)	6,488	6,594
Less: original issue discount on US dollar debt securities (1)	(21)	(22)
	6,467	6,572
Fair value of interest rate swaps on US dollar debt securities (2)	54	38
	6,521	6,610
Long-term debt before transaction costs	8,535	9,707
Less: transaction costs (1) (3)	(45)	(49)
	$ 8,490	$ 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 $54 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 September 30, 2010, the Company had in place unsecured bank credit facilities of $3,954 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 September 30, 2010 was 1.6% (December 31, 2009 – 0.8%), and on total long-term debt outstanding for the three months ended September 30, 2010 was 4.9% (December 31, 2009 – 4.5%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $312 million, including $235 million related to Horizon, were outstanding at September 30, 2010. Subsequent to September 30, 2010, the financial guarantee related to Horizon was reduced to $205 million.

Medium-term notes

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

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

	Sep 30 2010	Dec 31 2009
Asset retirement obligations	**$ 1,601**	$ 1,610
Stock-based compensation	**210**	392
Risk management (note 11)	**110**	309
Other	**106**	180
	2,027	2,491
Less: current portion	**210**	643
	$ 1,817	$ 1,848

Asset retirement obligations

At September 30, 2010, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $6,656 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 6.8% (December 31, 2009 – 6.9%). A reconciliation of the discounted asset retirement obligations is as follows:

	Nine Months Ended Sep 30, 2010	Year Ended Dec 31, 2009
Balance – beginning of period	**$ 1,610**	$ 1,064
Liabilities incurred (1)	**9**	299
Liabilities acquired	**8**	–
Liabilities settled	**(99)**	(48)
Asset retirement obligation accretion	**80**	90
Revision of estimates	**4**	276
Foreign exchange	**(11)**	(71)
Balance – end of period	**$ 1,601**	$ 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.

	Nine Months Ended Sep 30, 2010	Year Ended Dec 31, 2009
Balance – beginning of period	**$ 392**	$ 171
Stock-based compensation (recovery) expense	**(42)**	355
Cash payments for options surrendered	**(39)**	(94)
Transferred to common shares	**(104)**	(42)
Capitalized to Oil Sands Mining and Upgrading	**3**	2
Balance – end of period	**210**	392
Less: current portion	**164**	365
	$ 46	$ 27

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Current income tax – North America [(1)]	**$ 115**	$ 7	**$ 383**	$ 17
Current income tax – North Sea	**23**	55	**119**	218
Current income tax – Offshore West Africa	**25**	28	**40**	59
Current income tax expense	**163**	90	**542**	294
Future income tax expense (recovery)	**40**	83	**306**	(174)
Income tax expense	**$ 203**	$ 173	**$ 848**	$ 120

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

Taxable income from the conventional crude oil and natural gas 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 the proposed change in Canada to the taxation of stock options surrendered by employees for cash. During the first quarter of 2009, substantively enacted or 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 ultimately arising from these reassessments will be material.

7. SHARE CAPITAL

	Nine Months Ended Sep 30, 2010	
Issued **Common shares**	**Number of shares** (thousands) [(1)]	**Amount**
Balance – beginning of period	**1,084,654**	**$ 2,834**
Issued upon exercise of stock options	**5,011**	**83**
Previously recognized liability on stock options exercised for common shares	**–**	**104**
Cancellation of common shares	**(14)**	**–**
Purchase of common shares under Normal Course Issuer Bid	**(2,000)**	**(6)**
Balance – end of period	**1,087,651**	**$ 3,015**

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

Dividend Policy

On March 3, 2010, the Board of Directors set the regular quarterly dividend at $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 September 30, 2010, the Company purchased 2,000,000 common shares 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.

	Nine Months Ended Sep 30, 2010		
Stock options	**Stock options** (thousands) [1]		**Weighted average exercise price** [1]
Outstanding – beginning of period	**64,211**	**$**	**29.27**
Granted	**3,340**	**$**	**35.93**
Surrendered for cash settlement	**(2,319)**	**$**	**19.48**
Exercised for common shares	**(5,011)**	**$**	**16.58**
Forfeited	**(2,187)**	**$**	**32.19**
Outstanding – end of period	**58,034**	**$**	**31.03**
Exercisable – end of period	**19,189**	**$**	**30.06**

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

8. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Sep 30 2010		Sep 30 2009
Derivative financial instruments designated as cash flow hedges	**$**	**94**	$	85
Foreign currency translation adjustment		**(191)**		(146)
	$	**(97)**	$	(61)

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's internal targeted range for its debt to book capitalization ratio is 35% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, and lower commodity prices occurs. 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 ratio is currently at 28%.

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.

		Sep 30 2010		Dec 31 2009
Long-term debt	**$**	**8,490**	$	9,658
Total shareholders' equity	**$**	**21,420**	$	19,426
Debt to book capitalization		**28%**		33%

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2010	Sep 30 2009 (1)	**Sep 30 2010**	Sep 30 2009 (1)
Weighted average common shares outstanding (thousands) – basic and diluted	**1,088,989**	1,084,274	**1,087,794**	1,083,597
Net earnings – basic and diluted	**$ 580**	$ 658	**$ 2,113**	$ 1,125
Net earnings per common share – basic and diluted	**$ 0.53**	$ 0.61	**$ 1.94**	$ 1.04

(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:

	Sep 30, 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	**$ –**	**$ 27**	**$ –**
Accounts receivable	**1,246**	**–**	**–**
Other long-term assets	**–**	**–**	**–**
Accounts payable	**–**	**–**	**(274)**
Accrued liabilities	**–**	**–**	**(1,891)**
Other long-term liabilities	**–**	**(110)**	**(95)**
Long-term debt	**–**	**–**	**(8,490)**
	$ 1,246	**$ (83)**	**$ (10,750)**

	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	–	–
Other long-term assets	–	–	–
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:

	Sep 30, 2010		
	Carrying value	**Fair value**	
Asset (liability) [(1)]		**Level 1**	**Level 2**
Other long-term assets	**$ –**	**$ –**	**$ –**
Other long-term liabilities	**(110)**	**–**	**(110)**
Fixed-rate long-term debt[(2)(3)]	**(7,676)**	**(8,675)**	**–**
	$ (7,786)	**$ (8,675)**	**$ (110)**

	Dec 31, 2009		
	Carrying value	Fair value	
Asset (liability) [(1)]		Level 1	Level 2
Other long-term assets	$ –	$ –	$ –
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 $54 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:

	Nine Months Ended Sep 30, 2010	Year Ended Dec 31, 2009
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ (309)**	$ 2,119
Net change in fair value of outstanding derivative financial instruments attributable to:		
– Risk management activities	**198**	(1,991)
– Interest expense	**19**	(25)
– Foreign exchange	**(30)**	(338)
– Other comprehensive income	**12**	(78)
– Settlement of interest rate swaps and other	**–**	4
Balance – end of period	**(110)**	(309)
Less: current portion	**(18)**	(182)
	$ (92)	$ (127)

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2010	Sep 30 2009	**Sep 30 2010**	Sep 30 2009
Net realized risk management gain	**$ (70)**	$ (200)	**$ (122)**	$ (1,131)
Net unrealized risk management loss (gain)	**92**	274	**(198)**	1,683
	$ 22	$ 74	**$ (320)**	$ 552

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 September 30, 2010, the Company had the following net derivative financial instruments outstanding:

i) Sales Contracts

	Remaining term			Volume	Weighted average price			Index
Crude oil (1)								
Crude oil price collars (2)	Oct 2010	–	Dec 2010	50,000 bbl/d	US$60.00	–	US$75.08	WTI
	Oct 2010	–	Dec 2010	50,000 bbl/d	US$65.00	–	US$108.94	WTI
	Oct 2010	–	Dec 2010	50,000 bbl/d	US$70.00	–	US$105.81	WTI
	Jan 2011	–	Dec 2011	23,000 bbl/d	US$70.00	–	US$102.33	WTI

(1) Subsequent to September 30, 2010, the Company entered into 100,000 bbl/d of US$70 WTI put options for the period January to December 2011 for a total cost of US$106 million.

(2) Subsequent to September 30, 2010, the Company entered into an additional 27,000 bbl/d of US$70 – US$102.14 WTI collars for the period January to December 2011.

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars	Oct 2010	–	Dec 2010	220,000 GJ/d	C$6.00	–	C$8.00	AECO

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.

All commodity derivative financial instruments designated as hedges at September 30, 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 September 30, 2010, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating (1)	Oct 2010	–	Dec 2014	US$350	4.90%	LIBOR (2) + 0.38%
Swaps – floating to fixed	Oct 2010	–	Feb 2011	C$300	1.0680%	3 month CDOR (3)
	Oct 2010	–	Feb 2012	C$200	1.4475%	3 month CDOR (3)

(1) Subsequent to September 30, 2010, the Company unwound US$350 million of 4.9% interest rate swaps for proceeds of US$54 million.

(2) London Interbank Offered Rate

(3) Canadian Dealer Offered Rate

All fixed to floating interest rate related derivative financial instruments designated as hedges at September 30, 2010 were classified as fair value hedges.

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 September 30, 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	Oct 2010	–	Jul 2011	US$100	0.999	6.70%	7.64%
	Oct 2010	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2010	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2010	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at September 30, 2010 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2010 the Company had US$1,167 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 September 30, 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	$ (6)	$ –
Decrease WTI US$1.00/bbl	$ 6	$ –
Increase AECO C$0.10/mcf	$ (1)	$ 3
Decrease AECO C$0.10/mcf	$ 1	$ (3)
Interest rate risk		
Increase interest rate 1%	$ (4)	$ 9
Decrease interest rate 1%	$ 4	$ (16)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (28)	$ –
Decrease exchange rate by US$0.01	$ 28	$ –

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 September 30, 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 September 30, 2010, the Company had net risk management assets of $12 million 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	$ 1,891	$ –	$ –	$ –
Risk management	$ 18	$ 20	$ 30	$ 42
Other long-term liabilities	$ 28	$ 23	$ 44	$ –
Long-term debt (1)	$ 812	$ –	$ 1,932	$ 4,944

(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 $814 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at September 30, 2010, the Company had committed to certain payments as follows:

	Remaining 2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 58	$ 220	$ 193	$ 167	$ 163	$ 1,085
Offshore equipment operating leases	$ 42	$ 135	$ 102	$ 100	$ 101	$ 258
Offshore drilling	$ 11	$ 8	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 4	$ 24	$ 21	$ 31	$ 39	$ 6,537
Office leases	$ 7	$ 27	$ 28	$ 29	$ 29	$ 391
Other	$ 87	$ 74	$ 28	$ 18	$ 16	$ 38

(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 2010 – 2014 represent the estimated minimum expenditures required to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

	Conventional Crude Oil and Natural Gas															
	North America				North Sea				Offshore West Africa				Total Conventional			
(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**2,221**	1,906	**7,197**	5,753	**224**	220	**755**	666	**290**	223	**623**	606	**2,735**	2,349	**8,575**	7,025
Less: royalties	**(268)**	(196)	**(882)**	(581)	**–**	–	**(1)**	(1)	**(25)**	(29)	**(40)**	(59)	**(293)**	(225)	**(923)**	(641)
Segmented revenue, net of royalties	**1,953**	1,710	**6,315**	5,172	**224**	220	**754**	665	**265**	194	**583**	547	**2,442**	2,124	**7,652**	6,384
Segmented expenses																
Production	**422**	436	**1,259**	1,357	**123**	90	**280**	273	**52**	43	**121**	116	**597**	569	**1,660**	1,746
Transportation and blending	**344**	237	**1,305**	867	**2**	1	**7**	6	**1**	1	**1**	1	**347**	239	**1,313**	874
Depletion, depreciation and amortization	**585**	512	**1,728**	1,573	**70**	53	**222**	196	**108**	45	**232**	133	**763**	610	**2,182**	1,902
Asset retirement obligation accretion	**11**	10	**33**	30	**9**	6	**25**	19	**2**	1	**5**	3	**22**	17	**63**	52
Realized risk management activities	**(70)**	(130)	**(122)**	(802)	**–**	(70)	**–**	(329)	**–**	–	**–**	–	**(70)**	(200)	**(122)**	(1,131)
Total segmented expenses	**1,292**	1,065	**4,203**	3,025	**204**	80	**534**	165	**163**	90	**359**	253	**1,659**	1,235	**5,096**	3,443
Segmented earnings before the following	**661**	645	**2,112**	2,147	**20**	140	**220**	500	**102**	104	**224**	294	**783**	889	**2,556**	2,941
Non-segmented expenses																
Administration																
Stock-based compensation expense (recovery)																
Interest, net																
Unrealized risk management activities																
Foreign exchange gain																
Total non-segmented expenses																
Earnings before taxes																
Taxes other than income tax																
Current income tax expense																
Future income tax expense (recovery)																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2010	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Segmented revenue	**604**	469	**1,949**	761	**19**	18	**59**	54	**(17)**	(13)	**(48)**	(81)	**3,341**	2,823	**10,535**	7,759
Less: royalties	**(20)**	(15)	**(67)**	(18)	**–**	–	**–**	–	**–**	–	**–**	8	**(313)**	(240)	**(990)**	(651)
Segmented revenue, net of royalties	**584**	454	**1,882**	743	**19**	18	**59**	54	**(17)**	(13)	**(48)**	(73)	**3,028**	2,583	**9,545**	7,108
Segmented expenses																
Production	**268**	242	**904**	424	**4**	4	**16**	14	**(2)**	(2)	**(7)**	(16)	**867**	813	**2,573**	2,168
Transportation and blending	**15**	13	**46**	27	**–**	–	**–**	–	**(12)**	(11)	**(36)**	(34)	**350**	241	**1,323**	867
Depletion, depreciation and amortization	**86**	66	**270**	104	**2**	2	**6**	6	**–**	(5)	**–**	(29)	**851**	673	**2,458**	1,983
Asset retirement obligation accretion	**6**	7	**17**	15	**–**	–	**–**	–	**–**	–	**–**	–	**28**	24	**80**	67
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(70)**	(200)	**(122)**	(1,131)
Total segmented expenses	**375**	328	**1,237**	570	**6**	6	**22**	20	**(14)**	(18)	**(43)**	(79)	**2,026**	1,551	**6,312**	3,954
Segmented earnings before the following	**209**	126	**645**	173	**13**	12	**37**	34	**(3)**	5	**(5)**	6	**1,002**	1,032	**3,233**	3,154
Non-segmented expenses																
Administration													**43**	38	**157**	132
Stock-based compensation expense (recovery)													**18**	172	**(42)**	268
Interest, net													**109**	118	**329**	299
Unrealized risk management activities													**92**	274	**(198)**	1,683
Foreign exchange gain													**(64)**	(424)	**(68)**	(547)
Total non-segmented expenses													**198**	178	**178**	1,835
Earnings before taxes													**804**	854	**3,055**	1,319
Taxes other than income tax													**21**	23	**94**	74
Current income tax expense													**163**	90	**542**	294
Future income tax expense (recovery)													**40**	83	**306**	(174)
Net earnings													**580**	658	**2,113**	1,125

Net additions to property, plant and equipment

	Nine Months Ended					
	Sep 30, 2010			Sep 30, 2009		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 2,769**	**$ 17**	**$ 2,786**	$ 1,227	$ (4)	$ 1,223
North Sea	**111**	**4**	**115**	120	–	120
Offshore West Africa	**204**	**(2)**	**202**	464	51	515
Other	**2**	**–**	**2**	1	–	1
Oil Sands Mining and Upgrading (2)	**357**	**5**	**362**	446	275	721
Midstream	**4**	**–**	**4**	5	–	5
Head office	**13**	**–**	**13**	9	–	9
	$ 3,460	**$ 24**	**$ 3,484**	$ 2,272	$ 322	$ 2,594

(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	
	Sep 30 2010	Dec 31 2009	**Sep 30 2010**	Dec 31 2009
Segmented assets				
North America	**$ 22,908**	$ 21,834	**$ 23,932**	$ 22,994
North Sea	**1,654**	1,812	**1,787**	1,968
Offshore West Africa	**1,795**	1,883	**1,985**	2,033
Other	**30**	28	**50**	42
Oil Sands Mining and Upgrading	**13,387**	13,295	**13,818**	13,621
Midstream	**201**	203	**293**	306
Head office	**60**	60	**60**	60
	$ 40,035	$ 39,115	**$ 41,925**	$ 41,024

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 nine months ended September 30, 2010, pre-tax interest of $19 million was capitalized to Oil Sands Mining and Upgrading (September 30, 2009 – $98 million).

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 September 30, 2010:	
Interest coverage (times)	
Net earnings [(1)]	8.6x
Cash flow from operations [(2)]	16.0x

(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.

CORPORATE INFORMATION

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Vice-Chairman

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Vice-President, Thermal Exploration

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Vice-President, Thermal Exploitation

Lynn M. Zeidler
Vice-President, Horizon Technical,
Business & Common Services

Bruce E. McGrath
Corporate Secretary

*Management Committee

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

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David A. Tuer

International Operations

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Vice-President, Exploration, International

Barry Duncan
Vice-President, Finance, International

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