Canadian Natural

PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2015 THIRD QUARTER RESULTS

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Commenting on third quarter results, Steve Laut, President of Canadian Natural stated, “The third quarter was a very strong operational quarter, as we continue to make significant progress in reducing costs while maintaining effective, efficient and reliable operations across our business segments. Our disciplined approach has led to operating costs per barrel equivalent reductions in 2015 equating to approximately $945 million. At the same time our average production has increased 11% despite a very significant drop in capital program spending. We look to maintain this positive momentum into 2016, with 2016 production volumes targeted at roughly the same level as in 2015. We currently anticipate 2016 cash flows to cover 2016 capital expenditures between $4.5 and $5.0 billion, which includes approximately $2.1 billion of Horizon expansion project expenditures. Importantly, we target to exit 2016 with Horizon production volumes at 170,000 bbl/d and the Phase 3 expansion well advanced toward completion in Q4/17. For 2017, Horizon expansion project expenditure levels are targeted between $1.0 and $1.3 billion, as we complete the Horizon expansion.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “In 2015, we have been exceptionally proactive in managing our balance sheet and exhibiting capital discipline, given the significant decline in commodity prices. To date, and including the most recent reduction in capital expenditure guidance of $65 million, we have reduced our targeted capital expenditures by approximately $3.2 billion in 2015 from the original budget, while at the same time increasing crude oil and natural gas production by a targeted 9% year over year. For the first nine months, our cash flow funded all but $300 million of our capital expenditures and dividends paid, including over $1.6 billion of Horizon Phase 2/3 expansion costs. Our liquidity remains robust at $3.4 billion, and the balance sheet remains resilient through this commodity price cycle with our solid access to debt capital markets, as we maintain strong investment grade credit ratings.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended Sep 30 2015	June 30 2015	Sep 30 2014	Nine Months Ended Sep 30 2015	Sep 30 2014
Net earnings (loss)	**$ (111)**	$ (405)	$ 1,039	**$ (768)**	$ 2,731
Per common share – basic	**$ (0.10)**	$ (0.37)	$ 0.95	**$ (0.70)**	$ 2.50
– diluted	**$ (0.10)**	$ (0.37)	$ 0.94	**$ (0.70)**	$ 2.49
Adjusted net earnings from operations (1)	**$ 113**	$ 178	$ 984	**$ 312**	$ 3,055
Per common share – basic	**$ 0.10**	$ 0.16	$ 0.90	**$ 0.28**	$ 2.80
– diluted	**$ 0.10**	$ 0.16	$ 0.89	**$ 0.28**	$ 2.78
Cash flow from operations (2)	**$ 1,533**	$ 1,503	$ 2,440	**$ 4,406**	$ 7,219
Per common share – basic	**$ 1.40**	$ 1.38	$ 2.23	**$ 4.03**	$ 6.61
– diluted	**$ 1.40**	$ 1.37	$ 2.21	**$ 4.02**	$ 6.57
Capital expenditures, net of dispositions	**$ 1,240**	$ 1,297	$ 2,175	**$ 3,949**	$ 9,524
Daily production, before royalties					
Natural gas (MMcf/d)	**1,653**	1,779	1,674	**1,734**	1,497
Crude oil and NGLs (bbl/d)	**573,135**	509,047	518,007	**561,554**	517,428
Equivalent production (BOE/d) (3)	**848,701**	805,547	796,931	**850,587**	766,871

(1) 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 the Management's Discussion and Analysis ("MD&A").

(2) 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.

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

- Canadian Natural maintained its focus on safe, effective and efficient operations in the third quarter of 2015 demonstrated by solid production volumes. 2015 third quarter production volumes averaged 848,701 BOE/d, an increase of 6% and 5% from Q3/14 and Q2/15 volumes respectively. Q3/15 operational highlights include:
  - Horizon Oil Sands ("Horizon") production volumes averaged 131,779 bbl/d of synthetic crude oil ("SCO"), an increase of 61% and 36% from Q3/14 and Q2/15 levels respectively. Safe and reliable operations remain inherent throughout Horizon as the plant utilization rate in Q3/15 of 96% was at the high end of our target range of 92% to 96%. Quarterly operating expenses at a new benchmark low of $27.04/bbl resulted from strong production volumes. 2015 annual operating cost guidance has been lowered and is now targeted to range from $29.00/bbl to $32.00/bbl.
  - Offshore Africa crude oil production averaged 21,077 bbl/d, an increase of 54% over Q3/14 and 23% over Q2/15 levels, resulting from the successful execution of the ongoing Espoir and Baobab infill drilling programs.
    - To date, the Espoir infill drilling program has added approximately 5,300 bbl/d net to the Company. Espoir is targeted to add overall net production volumes of 5,900 bbl/d through a 10 gross well (5.9 net well) program which includes 4 water injection wells and is currently tracking below sanctioned costs and on track for production. For the first nine months of 2015, 5 gross wells were drilled and completed for production (no water injection wells drilled to date).

– At Baobab, 3 gross wells were drilled and completed during the first nine months of 2015. Net incremental production volumes currently average approximately 6,300 bbl/d. Production from the fourth gross well is targeted to come on stream in the fourth quarter of 2015. Baobab is targeted to add overall net production volumes of 11,000 bbl/d through a 6 gross well (3.4 net well) program, where progress is currently tracking below sanctioned costs and on track for production.

- At Pelican Lake, excellent operating efficiencies continue to be a focus as industry leading operating costs of $6.64/bbl were achieved, a decrease of 15% from Q3/14 and 5% from Q2/15 levels. Despite no drilling activity during the year, production volumes continue to be strong at 50,852 bbl/d and this leading edge polymer flood continues to meet expectations.
- Kirby South, the Company's largest Steam Assisted Gravity Drainage ("SAGD") operation, continues to ramp up to 40,000 bbl/d. Q3/15 production volumes were 34,069 bbl/d, an increase of 88% from Q3/14 and 30% over Q2/15 volumes.

▪ The expansion activities at Horizon continue to progress on track with overall physical completion of 74%. Horizon project capital costs continue to trend below budget estimates. Over the next twenty months, the Company is targeted to complete the Phase 2/3 expansion, adding an incremental 125,000 bbl/d of SCO to the Company's large, balanced and diversified asset base. Horizon will provide significant and sustainable production for decades to come.

▪ Canadian Natural continues to execute capital discipline by proactively managing its drilling programs. As a result of the decrease in commodity pricing and other external events, the Company's drilling activity for the first nine months of 2015 consisted of 134 net wells, excluding strat/service wells, compared to 768 net wells for the first nine months of 2014, a reduction of 83%.

▪ Canadian Natural remains committed to its effective and efficient operations, with an enhanced focus on cost optimization. During the third quarter, the Company achieved strong operating cost reductions in the following areas:

	Q3/15	Q3/14	Year over Year Percent Reduction
North America Light Crude Oil and NGLs ($/bbl)	**$ 14.37**	$ 17.67	**19%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$ 6.64**	$ 7.82	**15%**
Primary Heavy Crude Oil ($/bbl)	**$ 13.81**	$ 17.52	**21%**
Horizon Oil Sands Mining and Upgrading ($/bbl) (1)	**$ 27.04**	$ 37.13	**27%**
North Sea Light Crude Oil ($/bbl)	**$ 72.69**	$ 76.48	**5%**
North America Natural Gas ($/Mcf)	**$ 1.25**	$ 1.36	**8%**

(1) Horizon Q3/14 operating costs adjusted to reflect the impact of the maintenance turnaround completed in Q3/14.

▪ Due to the timing of liftings from the various fields in Offshore Africa that have different cost structures, and a weaker Canadian dollar, a quarterly cost comparison year over year is not indicative of performance. However, on an annual basis, due to the ongoing infill drilling program in Côte d'Ivoire and a continued focus on effective and efficient operations, Offshore Africa crude oil operating costs are targeted to reduce by 37% on a produced barrel basis, 2015 year over 2014 year.

▪ Given the cyclical nature of Primrose operations and the continued ramp up of production volumes at Kirby South, quarterly cost comparison year over year is not indicative of performance. However, on an annual basis, with a continued focus on effective and efficient operations, thermal operating costs are targeted to reduce by 16% on a produced barrel basis, 2015 year over 2014 year.

▪ In addition to the operating cost efficiencies achieved during the quarter, Canadian Natural has lowered its targeted 2015 capital spending program by an additional $65 million from $5,500 million to $5,435 million. This reduction is a result of the Company's ability to optimize its execution strategy, enhance productivity, right scope projects, leverage technology, and achieve lower energy and material costs.

▪ Year to date, Canadian Natural has been able to attain drilling and completions cost reductions from 20% to 35% and facility cost decreases from 20% to 30% throughout its North America Exploration & Production ("E&P") operations. These reductions have contributed to the Company's ability to decrease its targeted 2015 capital expenditure program by a total of approximately $3.2 billion since November 2014.

- Canadian Natural generated cash flow from operations of approximately $1.5 billion in Q3/15 compared to approximately $2.4 billion in Q3/14 and $1.5 billion in Q2/15. The decrease in Q3/15 from Q3/14 primarily reflects lower benchmark pricing partially offset by reduced operating costs and increased crude oil production volumes.
- The Company incurred a net loss in Q3/15 of $111 million, compared to net earnings of $1,039 million in Q3/14 and a net loss of $405 million in Q2/15. Adjusted net earnings from operations for Q3/15 were $113 million, compared to adjusted net earnings of $984 million in Q3/14 and $178 million in Q2/15. Changes in adjusted net earnings largely reflect the changes in cash flow from operations.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on December 31, 2015.

PRELIMINARY GUIDANCE ON 2016

- At this time, due to the current volatile issues facing the energy industry on both a national and global basis, Canadian Natural has not finalized its 2016 Budget plan. However, below we provide preliminary guidance for 2016.

  In 2016, the Company is committed to the following priorities:
  - Continued focus on lowering cost structures,
  - Completion of Horizon Phase 2B and progression of Phase 3 toward completion in Q4/17,
  - Maintenance of the Company's strong balance sheet,
  - Maintenance of the Company's dividend program, and
  - Preservation of the optionality of the Company's reserves and land base.
- **Operational Targets**

  Canadian Natural's overall production levels in 2016 is targeted to be between 840,000 BOE/d and 850,000 BOE/d, with a product mix of approximately 65% crude oil and NGLs and 35% natural gas.
- **Target Capital Program**

  Canadian Natural anticipates a 2016 capital program in the range of $4.5 billion to $5.0 billion, with approximately $2.1 billion allocated to Horizon Phase 2B and Phase 3 construction.
- **Lowering Cost Structures**

  Canadian Natural has made significant strides in 2015 to lower the Company's overall cost structures. In 2016, the Company will continue to focus on productivity improvements in all areas of our business.
- **Horizon Operations and Expansion Highlights**

  Canadian Natural's plan is to complete Phase 2B of the Horizon expansion in Q4/16, and Phase 3 in Q4/17. Phase 2B is targeted to add 45,000 bbl/d of production capacity once fully commissioned in early Q4/16. Project capital in 2016 is targeted to be approximately $2.1 billion, the majority of which will be spent over the first nine months of 2016. In 2017, Horizon project capital is targeted to decline to a range of $1.0 billion to $1.3 billion for Phase 3 completion, which will add incremental production volumes of 80,000 bbl/d. At expansion completion, targeted for Q4/17, total Horizon production volumes are targeted at 250,000 bbl/d of SCO with targeted operating costs below $25.00/bbl.
- **Maintenance of Strong Balance Sheet**

  Balance Sheet metrics are fundamental to the Company's success and well within range of Management's debt to book capitalization parameters of 25% to 45%. As at September 30, 2015, unused bank lines of credit were approximately $3.4 billion. Canadian Natural is in a strong position to carry through on its plans for 2016.
- **Canadian Natural's Dividend Program**

  Canadian Natural instituted the payment of a quarterly dividend in 2001 and has increased the dividend for 15 consecutive years. It is the current intention of the Board of Directors and the Management Committee to continue the program through the completion of the Horizon expansion project.
- **Preservation of the optionality of the Company's reserves and undeveloped lands**

  Canadian Natural has a strong, balanced and diversified portfolio of short-, mid- and long-term natural gas, heavy crude oil and light crude oil projects, which will be maintained to ensure optionality of the Company's asset base. Drilling activity will continue to be focused on value growth, not production growth.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate effective and efficient operations, Canadian Natural focuses its activities in core regions where the Company owns a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Furthermore, the Company maintains large project inventories and production diversification among each of the commodities it produces; light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as “crude oil”), natural gas and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

Drilling Activity

	Nine Months Ended Sep 30			
	2015		2014	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**124**	**113**	774	698
Natural gas	**22**	**15**	81	59
Dry	**6**	**6**	13	11
Subtotal	**152**	**134**	868	768
Stratigraphic test / service wells	**130**	**93**	365	363
Total	**282**	**227**	1,233	1,131
Success rate (excluding stratigraphic test / service wells)		**96%**		99%

- As a direct result of the decrease in crude oil and natural gas pricing and other external events, the Company has proactively reduced its 2015 drilling programs. Drilling activity, excluding strat/service wells, in Q3/15 consisted of 74 net wells compared to 300 net wells in Q3/14.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	June 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs production (bbl/d)	**264,709**	270,021	288,858	**273,609**	280,319
Net wells targeting crude oil	**67**	4	275	**111**	689
Net successful wells drilled	**63**	4	270	**105**	679
Success rate	**94%**	100%	98%	**95%**	99%

- Quarterly production volumes of North America crude oil and NGLs were 264,709 bbl/d in Q3/15, a decrease of 8% and 2% from Q3/14 and Q2/15 levels respectively. The year over year production decline reflects the 84% reduction in drilling activity from 689 net wells in the first nine months of 2014 to 111 net wells in the first nine months of 2015.
- North America light crude oil and NGL quarterly production averaged 88,195 bbl/d in Q3/15, a decrease of 6% from Q3/14 volumes and comparable to Q2/15 levels. Year over year decline primarily resulted from expected production declines as no wells were drilled in Q3/15 compared to 22 net wells drilled in Q3/14.
- Despite the reduction in production volumes, North America light crude oil and NGL quarterly operating costs decreased to $14.37/bbl in Q3/15, 19% lower than Q3/14 levels of $17.67/bbl and 6% lower than Q2/15 levels of $15.29/bbl.
- Pelican Lake operations averaged 50,852 bbl/d of quarterly heavy crude oil production, a 2% decrease from Q3/14 and Q2/15 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.

- Industry leading quarterly operating costs were achieved at Pelican Lake during Q3/15. Operating costs decreased to $6.64/bbl, 15% lower than Q3/14 and 5% lower than Q2/15.
- In Q3/15, primary heavy crude oil production averaged 125,662 bbl/d, a decrease of 12% and 2% from Q3/14 and Q2/15 levels respectively. This production decline from Q3/14 to Q3/15 reflects expected declines, the Company's proactive decision to reduce its primary heavy crude oil drilling program by 73% year over year, and the Company's prudent decision to shut-in approximately 5,700 bbl/d of current primary heavy crude oil production volumes as a result of unfavorable economic conditions. In Q3/15, 67 net wells were drilled compared to 245 net wells in Q3/14.
- Canadian Natural continues to demonstrate its strong focus on operating efficiencies achieving quarterly cost reductions in its primary heavy crude oil asset base. Primary heavy crude oil quarterly operating costs decreased in Q3/15 to $13.81/bbl compared to $17.52/bbl in Q3/14 and $14.92/bbl in Q2/15, cost reductions of 21% and 7% respectively.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	June 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Bitumen production (bbl/d)	**133,183**	105,019	115,256	**128,048**	104,037
Net wells targeting bitumen	**–**	–	1	**3**	15
Net successful wells drilled	**–**	–	1	**3**	15
Success rate	**–**	–	100%	**100%**	100%

- In Q3/15, thermal in situ production volumes averaged 133,183 bbl/d, an increase of 16% and 27% from Q3/14 and Q2/15 production volume levels respectively. The increase in Q3/15 from Q2/15 production volumes primarily reflects increased production volumes from Primrose operations and the ramp up of Kirby South operations.
- At Kirby South, quarterly production volumes continued to increase in Q3/15 to 34,069 bbl/d as operations continue to ramp up to the targeted 40,000 bbl/d of design capacity. The reservoir continues to perform as expected with very good thermal efficiencies. The steam to oil ratio ("SOR") in Q3/15 was 2.5. For October 2015, Kirby South's production volumes exited at an approximate rate of 36,000 bbl/d following a short shut down for maintenance on the oil treating vessels.
- The Company continues to progress the low pressure steamflood operations at Primrose East Area 1 and the low pressure cyclic steam stimulation ("CSS") operations at Primrose East Area 2. Operations at Primrose East are meeting expectations with current production volumes ranging from 15,000 bbl/d to 20,000 bbl/d.

Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	June 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Natural gas production (MMcf/d)	**1,592**	1,716	1,644	**1,673**	1,468
Net wells targeting natural gas	**4**	2	22	**15**	60
Net successful wells drilled	**4**	2	21	**15**	59
Success rate	**100%**	100%	95%	**100%**	98%

- North America natural gas quarterly production volumes averaged 1,592 MMcf/d for Q3/15, a decrease of 3% and 7% from Q3/14 and Q2/15 levels respectively. The decrease from Q2/15 levels reflects unplanned and planned pipeline take away capacity constraints in Alberta.
- Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading quarterly operating costs of $0.20/Mcfe in Q3/15.

- Canadian Natural's North America natural gas production volumes during Q3/15 were negatively impacted by transportation restrictions on the NOVA pipeline system by 89 MMcf/d. An additional 16 MMcf/d of natural gas production volumes were also negatively impacted as a result of an unexpected seven day outage of the Alliance pipeline system.
- Further restrictions on the NOVA pipeline system are expected in Q4/15 which will lower North America natural gas production volumes by approximately 70 MMcf/d. Canadian Natural's Q4/15 total natural gas production guidance reflects these impacts and is targeted to range from 1,735 MMcf/d to 1,775 MMcf/d.
- North America natural gas quarterly operating costs were $1.25/Mcf in Q3/15, an 8% decrease from Q3/14 levels of $1.36/Mcf, and a 2% decrease from Q2/15 levels of $1.28/Mcf, reflecting a continued focus on cost optimization.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	June 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil production (bbl/d)					
North Sea	**22,387**	20,330	18,197	**21,915**	15,848
Offshore Africa	**21,077**	17,070	13,684	**17,140**	12,557
Natural gas production (MMcf/d)					
North Sea	**35**	38	7	**36**	7
Offshore Africa	**26**	25	23	**25**	22
Net wells targeting crude oil	**2.6**	1.4	1.8	**4.6**	3.5
Net successful wells drilled	**2.6**	1.4	1.8	**4.6**	3.5
Success rate	**100%**	100%	100%	**100%**	100%

- International crude oil production averaged 43,464 bbl/d during Q3/15, an increase of 36% from Q3/14 levels and a 16% increase from Q2/15 levels. The increase in Q3/15 production volumes over Q3/14 levels was primarily due to completion and tie-in of new wells at the Baobab and Espoir fields during the second and third quarters of 2015 and the reinstatement of production from both the Banff FPSO and the Tiffany platform outages during 2014. The increase in Q3/15 production volumes from Q2/15 was primarily due to bringing new wells onstream at the Baobab and Espoir fields during Q3/15 and production volume increases from the Ninian field after planned turnaround activity performed in Q2/15.
- The infill drilling programs at the Espoir and Baobab fields in Côte d'Ivoire continue to be successfully executed with results meeting expectations.
    - To date, the Espoir infill drilling program has added approximately 5,300 bbl/d net to the Company. Espoir is targeted to add overall net production volumes of 5,900 bbl/d through a 10 gross well (5.9 net well) program which includes 4 water injection wells and is currently tracking below sanctioned costs and on track for production. For the first nine months of 2015, 5 gross wells were drilled and completed for production (no water injection wells drilled to date).
    - At Baobab, 3 gross wells were drilled and completed for production during the first nine months of 2015. Net incremental production volumes currently average approximately 6,300 bbl/d. Production from the fourth gross well is targeted to come on stream in the fourth quarter of 2015. Baobab is targeted to add overall net production volumes of 11,000 bbl/d through a 6 gross well (3.4 net well) program, where progress is currently tracking below sanctioned costs and on track for production.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	June 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Synthetic crude oil production (bbl/d) [(1)]	**131,779**	96,607	82,012	**120,842**	104,667

(1) The Company has commenced production of diesel for internal use at Horizon. Third quarter 2015 SCO production before royalties excludes 2,058 bbl/d of SCO consumed internally as diesel (second quarter 2015 – 2,410 bbl/d; third quarter 2014 – 875 bbl/d; nine months ended September 30, 2015 – 2,049 bbl/d; nine months ended September 30, 2014 – 295 bbl/d).

- Horizon quarterly production volumes were strong in Q3/15 averaging 131,779 bbl/d of SCO, an increase of 61% and 36% from Q3/14 and Q2/15 levels respectively. Increased production volumes in Q3/15, as compared to Q3/14 and Q2/15, reflect normal operating conditions as planned maintenance activities impacted previous quarters. Q4/15 production guidance is targeted to range from 123,000 bbl/d to 129,000 bbl/d, with a targeted utilization rate of 92% at the midpoint. 2015 annual production guidance remains unchanged at 121,000 bbl/d to 131,000 bbl/d.
- The Company achieved record quarterly operating costs at Horizon of $27.04/bbl as a result of safe, steady and reliable operations in Q3/15. 2015 annual operating cost guidance has been lowered and is now targeted to range from $29.00/bbl to $32.00/bbl.
- Canadian Natural continues to execute on its strategy to transition to a longer life, low decline asset base while delivering significant and sustainable production. Canadian Natural's staged expansion of Horizon to 250,000 bbl/d of SCO production capacity continues to progress ahead of schedule. Canadian Natural has committed to approximately 82% of the Engineering, Procurement and Construction contracts with over 78% of the construction contracts awarded to date, 85% being lump sum, ensuring greater cost certainty and efficiency.
- Overall Horizon Phase 2/3 expansion is 74% physically complete as at Q3/15:
    - Directive 74 includes technological investment and research into tailings management. This project remains on track and is 57% physically complete.
    - Phase 2B is 72% physically complete. This Phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. Due to continued strong construction performance on the Horizon expansion, certain components of this project will be tied-in during the mid-2016 turnaround. Full commissioning of the Phase 2B equipment will be completed as planned in early Q4/16, adding 45,000 bbl/d of production capacity.
    - Phase 3 is currently on budget and on schedule. This Phase is 67% physically complete, and includes the addition of extraction trains. Phase 3 is targeted to increase production capacity by 80,000 bbl/d in Q4/17 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.
    - Horizon project capital in 2016 is targeted to be approximately $2.1 billion, the majority of which will be spent over the first nine months of 2016. In 2017, Horizon project capital is targeted to decline to $1.0 billion to $1.3 billion for Phase 3 completion. Once Horizon expansion activities are completed in Q4/17, total Horizon production volumes are targeted to average 250,000 bbl/d of SCO with operating costs targeted below $25.00/bbl.

ROYALTY PRODUCTION AND REVENUE

Canadian Natural reports the following information for quarterly royalty volumes, which are based on the Company's current estimate of revenue and volumes attributable to Q2/15:

- The development of leased acreage is ongoing and lease requests on undeveloped acreage continue to be evaluated. Total drilling activity for the nine months of 2015 consisted of 251 wells with 235 drilled by third parties and 16 drilled by Canadian Natural.
- The Company continues to focus on lease compliance, well commitments, offset drilling obligations and compensatory royalties payable.
- Royalty production volumes highlighted below are not reported in Canadian Natural's quarterly production volumes. Third party royalty revenues are included in reported Product Sales in the Company's consolidated statement of earnings.

Royalty Production Volumes Comparison [1]

	Q2/15	Q1/15
Natural gas (MMcf/d)	21.8	22.4
Crude oil (bbl/d)	4,004	4,263
NGLs (bbl/d)	527	538
Total (BOE/d)	**8,157**	**8,537**

Royalty Production Volumes [1]

	Royalty volumes for Q2/15 attributable to		
	Third Party	**Canadian Natural** [2]	**Total**
Natural gas (MMcf/d)	18.7	3.1	21.8
Crude oil (bbl/d)	3,379	625	4,004
NGLs (bbl/d)	481	46	527
Total (BOE/d)	**6,979**	**1,178**	**8,157**

Royalty Revenue by Product [1]

	Royalty revenue for Q2/15 attributable to		
($ millions)	**Third Party**	**Canadian Natural** [2]	**Total**
Natural gas	$ 4	$ 1	$ 5
Crude oil	$ 18	$ 3	$ 21
NGLs	$ 2	$ –	$ 2
Other revenue [3]	$ 1	$ –	$ 1
Total	**$ 25**	**$ 4**	**$ 29**

Revenue by Royalty Classification [1]

	Royalty revenue for Q2/15 attributable to		
($ millions)	**Third Party**	**Canadian Natural** [2]	**Total**
Fee title	$ 15	$ 3	$ 18
Gross overriding royalty [4]	$ 9	$ 1	$ 10
Other revenue [3]	$ 1	$ –	$ 1
Total	**$ 25**	**$ 4**	**$ 29**

Royalty Realized Pricing [1]

	Q2/15
Natural gas ($/Mcf)	$ 2.41
Crude oil ($/bbl)	$ 58.43
NGLs ($/bbl)	$ 32.78
Total ($/BOE)	**$ 38.96**

Royalty Acreage

(gross acres, millions)	Leased to: Third Party and Unleased	Leased to: Canadian Natural (2)	Total
Fee title (5)	3.07	0.26	3.33
Gross overriding royalty (4)	1.82	1.67	3.49
Total	**4.89**	**1.93**	**6.82**

(1) Based on the Company's current estimate of revenue and volumes attributable to the noted period.
(2) Indicates Canadian Natural is both the Lessor and Lessee, thereby incurring intercompany royalties; in addition there are certain Canadian Natural fee title lands where the Company has production where no royalty burden has been recognized in this table.
(3) Includes sulphur revenue, bonus payments, lease rentals and compliance revenue.
(4) Includes Net Profit Interests and other royalties.
(5) Includes fee title and freehold lands.

MARKETING

	Three Months Ended: Sep 30 2015	Three Months Ended: June 30 2015	Three Months Ended: Sep 30 2014	Nine Months Ended: Sep 30 2015	Nine Months Ended: Sep 30 2014
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 46.44**	$ 57.96	$ 97.21	**$ 50.98**	$ 99.60
WCS blend differential from WTI (%) (2)	**28%**	20%	21%	**26%**	21%
SCO price (US$/bbl)	**$ 45.78**	$ 60.61	$ 94.31	**$ 50.55**	$ 98.20
Condensate benchmark pricing (US$/bbl)	**$ 44.20**	$ 57.98	$ 93.49	**$ 49.25**	$ 100.36
Average realized pricing before risk management (C$/bbl) (3)	**$ 41.55**	$ 53.09	$ 79.99	**$ 43.58**	$ 82.35
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.65**	$ 2.53	$ 4.00	**$ 2.66**	$ 4.32
Average realized pricing before risk management (C$/Mcf)	**$ 3.22**	$ 3.06	$ 4.54	**$ 3.22**	$ 5.03

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI (US$/bbl)**	**SCO Differential from WTI (US$/bbl)**	**Dated Brent Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**
2015						
July	$ 50.93	14.6%	$ (7.44)	$ 2.62	$ 5.61	$ (4.35)
August	$ 42.89	31.3%	$ (13.41)	$ (0.64)	$ 4.04	$ (1.36)
September	$ 45.47	41.7%	$ (18.97)	$ (4.05)	$ 2.15	$ (0.96)
October	$ 46.29	29.2%	$ (13.51)	$ 0.11	$ 2.27	$ (0.54)
November*	$ 46.37	32.6%	$ (15.14)	$ 0.43	$ 1.50	$ (1.12)
December*	$ 47.30	32.1%	$ (15.17)	$ 1.30	$ 1.41	$ (0.75)

**Based on current indicative pricing as at November 2, 2015. SCO and Condensate December pricing based on current indicative pricing as at November 2, 2015.*

- Volatility in supply and demand factors and geopolitical events continued to affect WTI and Brent pricing. The Organization of the Petroleum Exporting Countries' ("OPEC") decision to maintain crude oil production quotas resulted in a year over year decline in benchmark pricing.

- The WCS differential to WTI averaged US$13.21/bbl or 28% in Q3/15 compared to US$20.19/bbl or 21% in Q3/14. The WCS differential widened during Q3/15 compared to Q2/15 due to planned and unplanned refinery shutdowns in the US Midwest and seasonal demand. November 2015 and December 2015 indications of the WCS heavy differential are trending higher to US$15.14/bbl or 33% and US$15.17/bbl or 32%, respectively. This widening is mainly due to the seasonality of heavy crude oil demand in the winter months. Seasonal demand fluctuations, changes in transportation logistics and refinery utilization and shutdowns will continue to be reflected in WCS pricing.
- Canadian Natural contributed approximately 165,000 bbl/d of its heavy crude oil stream to the WCS blend in Q3/15. The Company remains the largest contributor to the WCS blend, accounting for 45% of the total blend.
- SCO pricing averaged US$45.78/bbl during Q3/15 compared to US$94.31/bbl in Q3/14 and US$60.61/bbl in Q2/15, as a result of changes in WTI benchmark pricing.
- AECO natural gas pricing in Q3/15 averaged $2.65/GJ, a decrease of 34% from Q3/14 and an increase of 5% from Q2/15 pricing. In Q3/15, US natural gas production was relatively constant to Q2/15 with natural gas inventories growing slightly above normal industry levels. Natural gas prices were lower in Q3/15 compared to Q3/14 primarily due to lower than average storage levels as a result of the cold winter temperatures in 2014.

NORTH WEST REDWATER UPGRADING AND REFINING

The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: www.nwrpartnership.com/brief-updates.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs and commodity hedging policy all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 848,701 BOE/d for Q3/15, with approximately 97% of total production located in G8 countries.
- Canadian Natural has a strong balance sheet with debt to book capitalization of 38% at September 30, 2015. All of the Company's credit facilities are subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 65%.
- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at September 30, 2015, the Company had in place bank credit facilities of $7,480 million, of which $3,440 million was available.
- Subsequent to September 30, 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Subsequent to September 30, 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Canadian Natural's strong investment grade ratings have been maintained.
- The Company's commodity hedging program is utilized to protect investment returns, support ongoing balance sheet strength and the cash flow for its capital expenditure programs. Details of the Company's commodity hedging program can be found on the Company's website at www.cnrl.com.
- Canadian Natural declared a quarterly cash dividend on common shares of C$0.23 per share payable on December 31, 2015.
- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Canadian Natural retains additional capital expenditure program flexibility to proactively adapt to changing market conditions.

OUTLOOK

The Company forecasts 2015 production levels before royalties to average between 555,000 and 591,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. Q4/15 production guidance before royalties is forecast to average between 562,000 and 588,000 bbl/d of crude oil and NGLs and between 1,735 and 1,775 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

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”, “proposed” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management’s Discussion and Analysis (“MD&A”), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil (“SCO”) that the Company may be reliant upon to transport its products to market 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 and proved plus probable crude oil, natural gas and natural gas liquids (“NGLs”) 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 disruptions or delays in the resumption of the mining, extracting or upgrading of 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 and in mining, extracting or upgrading the Company’s bitumen products; 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, natural gas and 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, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

This MD&A 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 three and nine months ended September 30, 2015 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended September 30, 2015 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. 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 adjusted cash production costs. These financial measures are not defined by IFRS 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 IFRS, 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 IFRS, in the "Financial Highlights" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are 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.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of 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 and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2015 in relation to the comparable periods in 2014 and the second quarter of 2015. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2014, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated November 3, 2015.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Product sales	**$ 3,316**	$ 3,662	$ 5,370	**$ 10,204**	$ 16,451
Net earnings (loss)	**$ (111)**	$ (405)	$ 1,039	**$ (768)**	$ 2,731
Per common share – basic	**$ (0.10)**	$ (0.37)	$ 0.95	**$ (0.70)**	$ 2.50
– diluted	**$ (0.10)**	$ (0.37)	$ 0.94	**$ (0.70)**	$ 2.49
Adjusted net earnings from operations (1)	**$ 113**	$ 178	$ 984	**$ 312**	$ 3,055
Per common share – basic	**$ 0.10**	$ 0.16	$ 0.90	**$ 0.28**	$ 2.80
– diluted	**$ 0.10**	$ 0.16	$ 0.89	**$ 0.28**	$ 2.78
Cash flow from operations (2)	**$ 1,533**	$ 1,503	$ 2,440	**$ 4,406**	$ 7,219
Per common share – basic	**$ 1.40**	$ 1.38	$ 2.23	**$ 4.03**	$ 6.61
– diluted	**$ 1.40**	$ 1.37	$ 2.21	**$ 4.02**	$ 6.57
Capital expenditures, net of dispositions	**$ 1,240**	$ 1,297	$ 2,175	**$ 3,949**	$ 9,524

(1) 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" presents 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.

(2) 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" presents 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 2015***	*Jun 30 2015*	*Sep 30 2014*	***Sep 30 2015***	*Sep 30 2014*
Net earnings (loss) as reported	***$ (111)***	*$ (405)*	*$ 1,039*	***$ (768)***	*$ 2,731*
Share-based compensation, net of tax (1)	***(87)***	*(79)*	*(122)*	***(102)***	*210*
Unrealized risk management (gain) loss, net of tax (2)	***(24)***	*162*	*(118)*	***147***	*(36)*
Unrealized foreign exchange loss (gain), net of tax (3)	***351***	*(76)*	*185*	***688***	*150*
Equity loss (gain) from investment, net of tax (4)	***20***	*(3)*	*–*	***32***	*–*
Gain on disposition of properties, net of tax (5)	***(36)***	*–*	*–*	***(36)***	*–*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)	***–***	*579*	*–*	***351***	*–*
Adjusted net earnings from operations	***$ 113***	*$ 178*	*$ 984*	***$ 312***	*$ 3,055*

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

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the 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, natural gas and foreign exchange.

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

(4) The Company's investment in the 50% owned North West Redwater Partnership is accounted for using the equity method of accounting. The non-cash equity loss (gain) from investment represents the Company's pro rata share of the North West Redwater Partnership's accounting loss (gain).

(5) During the third quarter of 2015, the Company recorded a pre-tax gain of $49 million ($36 million after-tax) related to the disposition of a number of North America crude oil and natural gas properties.

(6) During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

Cash Flow from Operations

($ millions)	Three Months Ended **Sep 30 2015**	 Jun 30 2015	 Sep 30 2014	Nine Months Ended **Sep 30 2015**	 Sep 30 2014
Net earnings (loss)	**$ (111)**	$ (405)	$ 1,039	**$ (768)**	$ 2,731
Non-cash items:					
Depletion, depreciation and amortization	**1,376**	1,280	1,226	**4,011**	3,474
Share-based compensation	**(87)**	(79)	(122)	**(102)**	210
Asset retirement obligation accretion	**44**	43	49	**130**	144
Unrealized risk management (gain) loss	**(29)**	215	(150)	**200**	(47)
Unrealized foreign exchange loss (gain)	**351**	(76)	185	**688**	150
Equity loss (gain) from investment	**20**	(3)	5	**32**	3
Deferred income tax expense	**18**	528	208	**264**	554
Gain on disposition of properties	**(49)**	–	–	**(49)**	–
Cash flow from operations	**$ 1,533**	$ 1,503	$ 2,440	**$ 4,406**	$ 7,219

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net loss for the nine months ended September 30, 2015 was $768 million compared with net earnings of $2,731 million for the nine months ended September 30, 2014. Net loss for the nine months ended September 30, 2015 included net after-tax expenses of $1,080 million compared with $324 million for the nine months ended September 30, 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity loss from investment, gain on disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2015 were $312 million compared with $3,055 million for the nine months ended September 30, 2014.

Net loss for the third quarter of 2015 was $111 million compared with net earnings of $1,039 million for the third quarter of 2014 and net loss of $405 million for the second quarter of 2015. Net loss for the third quarter of 2015 included net after-tax expenses of $224 million compared with net after-tax income of $55 million for the third quarter of 2014 and net after-tax expenses of $583 million for the second quarter of 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity loss (gain) from investment, gain on disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the third quarter of 2015 were $113 million compared with $984 million for the third quarter of 2014 and $178 million for the second quarter of 2015.

The decrease in adjusted net earnings for the nine months ended September 30, 2015 from the comparable period in 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and NGLs, SCO and natural gas sales volumes across all segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the third quarter of 2015 from the third quarter of 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment;
- lower crude oil and NGLs and natural gas sales volumes in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and natural gas and SCO sales volumes in the International and Oil Sands Mining and Upgrading segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the third quarter of 2015 from the second quarter of 2015 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower crude oil and NGLs sales volumes in the North Sea segment; and
- lower natural gas sales volumes in the North America segment;

partially offset by:

- higher SCO and crude oil and NGLs sales volumes in the Oil Sands Mining and Upgrading, North America and Offshore Africa segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

Cash flow from operations for the nine months ended September 30, 2015 was $4,406 million compared with $7,219 million for the nine months ended September 30, 2014. Cash flow from operations for the third quarter of 2015 was $1,533 million compared with $2,440 million for the third quarter of 2014 and $1,503 million for the second quarter of 2015. The fluctuations in cash flow from operations from the comparable periods were primarily due to the factors noted above relating to the decrease in adjusted net earnings, as well as due to the impact of cash taxes.

Total production before royalties for the nine months ended September 30, 2015 increased 11% to 850,587 BOE/d from 766,871 BOE/d for the nine months ended September 30, 2014. Total production before royalties for the third quarter of 2015 increased 6% to 848,701 BOE/d from 796,931 BOE/d for the third quarter of 2014 and increased 5% from 805,547 BOE/d for the second quarter of 2015.

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 2015**		Jun 30 2015		Mar 31 2015		Dec 31 2014
Product sales	**$**	**3,316**	$	3,662	$	3,226	$	4,850
Net earnings (loss)	**$**	**(111)**	$	(405)	$	(252)	$	1,198
Net earnings (loss) per common share								
– basic	**$**	**(0.10)**	$	(0.37)	$	(0.23)	$	1.10
– diluted	**$**	**(0.10)**	$	(0.37)	$	(0.23)	$	1.09
($ millions, except per common share amounts)		Sep 30 2014		Jun 30 2014		Mar 31 2014		Dec 31 2013
Product sales	$	5,370	$	6,113	$	4,968	$	4,330
Net earnings (loss)	$	1,039	$	1,070	$	622	$	413
Net earnings (loss) per common share								
– basic	$	0.95	$	0.98	$	0.57	$	0.38
– diluted	$	0.94	$	0.97	$	0.57	$	0.38

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

- **Crude oil pricing** – The impact of increased shale oil production in North America, fluctuating global supply/demand, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Dated Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the heavy crude oil drilling program, the impact and timing of acquisitions, and the impact of turnarounds at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to third party pipeline restrictions and pricing, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, and turnarounds at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison platform, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **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** – Fluctuations in the Canadian dollar relative to the US dollar, which 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 realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, 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 in the various periods.
- **Gains on acquisitions/disposition of properties** – Fluctuations due to the recognition of gains on dispositions in the third quarter of 2015 and acquisitions in the fourth quarter of 2014.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
WTI benchmark price (US$/bbl)	**$ 46.44**	$ 57.96	$ 97.21	**$ 50.98**	$ 99.60
Dated Brent benchmark price (US$/bbl)	**$ 50.39**	$ 61.95	$ 101.90	**$ 55.37**	$ 106.55
WCS blend differential from WTI (US$/bbl)	**$ 13.21**	$ 11.60	$ 20.19	**$ 13.18**	$ 21.15
WCS blend differential from WTI (%)	**28%**	20%	21%	**26%**	21%
SCO price (US$/bbl)	**$ 45.78**	$ 60.61	$ 94.31	**$ 50.55**	$ 98.20
Condensate benchmark price (US$/bbl)	**$ 44.20**	$ 57.98	$ 93.49	**$ 49.25**	$ 100.36
NYMEX benchmark price (US$/MMBtu)	**$ 2.77**	$ 2.67	$ 4.07	**$ 2.80**	$ 4.51
AECO benchmark price (C$/GJ)	**$ 2.65**	$ 2.53	$ 4.00	**$ 2.66**	$ 4.32
US/Canadian dollar average exchange rate (US$)	**$ 0.7640**	$ 0.8132	$ 0.9183	**$ 0.7936**	$ 0.9139

Substantially all of the Company’s production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent (“Brent”) indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. In the third quarter of 2015, realized prices continued to be impacted by the weak Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales, as realized pricing is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$50.98 per bbl for the nine months ended September 30, 2015, a decrease of 49% from US$99.60 per bbl for the nine months ended September 30, 2014. WTI averaged US$46.44 per bbl for the third quarter of 2015, a decrease of 52% from US$97.21 per bbl for the third quarter of 2014, and a decrease of 20% from US$57.96 per bbl for the second quarter of 2015.

Crude oil sales contracts for the Company’s North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$55.37 per bbl for the nine months ended September 30, 2015, a decrease of 48% from US$106.55 per bbl for the nine months ended September 30, 2014. Brent averaged US$50.39 per bbl for the third quarter of 2015, a decrease of 51% from US$101.90 per bbl for the third quarter of 2014, and a decrease of 19% from US$61.95 per bbl for the second quarter of 2015.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market together with the Organization of the Petroleum Exporting Countries’ (“OPEC”) decision to continue to maintain crude oil production quotas resulted in a decline in year-over-year benchmark pricing.

The WCS Heavy Differential averaged 26% for the nine months ended September 30, 2015, compared with 21% for the nine months ended September 30, 2014. The WCS Heavy Differential averaged 28% for the third quarter of 2015 compared with 21% for the third quarter of 2014 and 20% for the second quarter of 2015. The WCS Heavy Differential widened for the third quarter of 2015 from the second quarter of 2015 primarily due to planned and unplanned refinery shutdowns in the US Midwest.

The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$50.55 per bbl for the nine months ended September 30, 2015, a decrease of 49% from US$98.20 per bbl for the nine months ended September 30, 2014. The SCO price averaged US$45.78 per bbl for the third quarter of 2015, a decrease of 51% from US$94.31 per bbl for the third quarter of 2014, and a decrease of 24% from US$60.61 per bbl for the second quarter of 2015. The fluctuations in SCO pricing for the three and nine months ended September 30, 2015 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.80 per MMBtu for the nine months ended September 30, 2015, a decrease of 38% from US$4.51 per MMBtu for the nine months ended September 30, 2014. NYMEX natural gas prices averaged US$2.77 per MMBtu for the third quarter of 2015, a decrease of 32% from US$4.07 per MMBtu for the third quarter of 2014, and an increase of 4% from US$2.67 per MMBtu for the second quarter of 2015.

AECO natural gas prices for the nine months ended September 30, 2015 averaged $2.66 per GJ, a decrease of 38% from $4.32 per GJ for the nine months ended September 30, 2014. AECO natural gas prices for the third quarter of 2015 averaged $2.65 per GJ, a decrease of 34% from $4.00 per GJ for the third quarter of 2014, and an increase of 5% from $2.53 per GJ for the second quarter of 2015.

In the third quarter of 2015, natural gas pricing was comparable with the second quarter of 2015. US natural gas production was comparable between the second and third quarters of 2015 with natural gas inventories growing slightly above normal levels. Natural gas prices were lower in the third quarter of 2015 than the third quarter of 2014 primarily due to lower than average storage levels in 2014 as a result of the colder than normal winter temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**397,892**	375,040	404,114	**401,657**	384,356
North America – Oil Sands Mining and Upgrading [(1)]	**131,779**	96,607	82,012	**120,842**	104,667
North Sea	**22,387**	20,330	18,197	**21,915**	15,848
Offshore Africa	**21,077**	17,070	13,684	**17,140**	12,557
	573,135	509,047	518,007	**561,554**	517,428
Natural gas (MMcf/d)					
North America	**1,592**	1,716	1,644	**1,673**	1,468
North Sea	**35**	38	7	**36**	7
Offshore Africa	**26**	25	23	**25**	22
	1,653	1,779	1,674	**1,734**	1,497
Total barrels of oil equivalent (BOE/d)	**848,701**	805,547	796,931	**850,587**	766,871
Product mix					
Light and medium crude oil and NGLs	**15%**	16%	16%	**15%**	15%
Pelican Lake heavy crude oil	**6%**	6%	7%	**6%**	6%
Primary heavy crude oil	**15%**	16%	18%	**16%**	19%
Bitumen (thermal oil)	**16%**	13%	14%	**15%**	14%
Synthetic crude oil [(1)]	**16%**	12%	10%	**14%**	14%
Natural gas	**32%**	37%	35%	**34%**	32%
Percentage of product sales [(1) (2)] (excluding Midstream revenue)					
Crude oil and NGLs	**83%**	84%	85%	**83%**	85%
Natural gas	**17%**	16%	15%	**17%**	15%

(1) Third quarter 2015 SCO production before royalties excludes 2,058 bbl/d of SCO consumed internally as diesel (second quarter 2015 – 2,410 bbl/d; third quarter 2014 – 875 bbl/d; nine months ended September 30, 2015 – 2,049 bbl/d; nine months ended September 30, 2014 – 295 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**350,444**	326,445	329,533	**352,278**	309,855
North America – Oil Sands Mining and Upgrading	**129,355**	95,057	76,515	**118,930**	100,152
North Sea	**22,325**	20,300	18,062	**21,865**	15,773
Offshore Africa	**20,145**	16,342	12,276	**16,386**	11,600
	522,269	458,144	436,386	**509,459**	437,380
Natural gas (MMcf/d)					
North America	**1,527**	1,684	1,525	**1,617**	1,341
North Sea	**35**	38	7	**36**	7
Offshore Africa	**25**	24	19	**24**	19
	1,587	1,746	1,551	**1,677**	1,367
Total barrels of oil equivalent (BOE/d)	**786,734**	749,210	694,859	**789,030**	665,214

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

Crude oil and NGLs production for the nine months ended September 30, 2015 increased 9% to 561,554 bbl/d from 517,428 bbl/d for the nine months ended September 30, 2014. Crude oil and NGLs production for the third quarter of 2015 increased 11% to 573,135 bbl/d from 518,007 bbl/d for the third quarter of 2014 and increased 13% from 509,047 bbl/d for the second quarter of 2015. The increase in production for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to increased production in the Horizon and International segments as well as from acquisitions of producing Canadian crude oil properties in 2014. Crude oil and NGLs production for the third quarter of 2015 was within the Company's previously issued guidance of 559,000 to 590,000 bbl/d.

Natural gas production for the nine months ended September 30, 2015 increased 16% to 1,734 MMcf/d from 1,497 MMcf/d for the nine months ended September 30, 2014. Natural gas production for the third quarter of 2015 decreased 1% to 1,653 MMcf/d from 1,674 MMcf/d for the third quarter of 2014 and decreased 7% from 1,779 MMcf/d for the second quarter of 2015. The increase in natural gas production for the nine months ended September 30, 2015 from comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014 and growth from higher production volumes in the North Sea. Natural gas production for the three months ended September 30, 2015 decreased from the comparable periods primarily due to third party transmission pipeline restrictions in Northwest Alberta, involving certain transmission pipeline operators. The Company shut in total natural gas volumes averaging approximately 105 MMcf/d, higher than the 80 MMcf/d originally expected. These additional pipeline restrictions resulted in natural gas production of 1,653 MMcf/d for the third quarter of 2015, slightly below the Company's previously issued guidance of 1,670 to 1,690 MMcf/d.

2015 annual production guidance is now targeted to average between 555,000 and 591,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. Fourth quarter 2015 production guidance is targeted to average between 562,000 and 588,000 bbl/d of crude oil and NGLs and between 1,735 and 1,775 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2015 increased 5% to average 401,657 bbl/d from 384,356 bbl/d for the nine months ended September 30, 2014. For the third quarter of 2015, crude oil and NGLs production decreased 2% to average 397,892 bbl/d compared with 404,114 bbl/d for the third quarter of 2014 and increased 6% from 375,040 bbl/d for the second quarter of 2015. The increase in production for the nine months ended September 30, 2015 from the comparable period was primarily due to increased production in the Company's thermal areas, including Kirby South, and increased production related to the acquisitions of producing Canadian crude oil properties in 2014. The increase in production for the third quarter of 2015 from the second quarter of 2015 was primarily due to the reinstatement of production in the thermal production areas after the forest fires in Northeastern Alberta in the second quarter of 2015. Third quarter 2015 production of crude oil and NGLs was within the Company's previously issued guidance of 393,000 to 413,000 bbl/d. Fourth quarter 2015 production guidance is targeted to average between 388,000 and 404,000 bbl/d of crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2015 increased 14% to 1,673 MMcf/d compared with 1,468 MMcf/d for the nine months ended September 30, 2014. Natural gas production decreased 3% to 1,592 MMcf/d for the third quarter of 2015 compared with 1,644 MMcf/d in the third quarter of 2014 and decreased 7% from 1,716 for the second quarter of 2015. The increase in natural gas production for the nine months ended September 30, 2015 from the comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014. Natural gas production for the three months ended September 30, 2015 decreased from the comparable periods primarily due to third party transmission pipeline restrictions in Northwest Alberta, involving certain transmission pipeline operators. The Company shut in total natural gas volumes averaging approximately 105 MMcf/d, higher than the 80 MMcf/d originally expected.

North America – Oil Sands Mining and Upgrading

SCO production for the nine months ended September 30, 2015 increased 15% to 120,842 bbl/d from 104,667 bbl/d for the nine months ended September 30, 2014. For the third quarter of 2015, SCO production increased 61% to 131,779 bbl/d from 82,012 bbl/d for the third quarter of 2014 and increased 36% from 96,607 bbl/d for the second quarter of 2015. Production in the third quarter of 2015 continued to reflect high utilization rates and reliability, following the completion of the planned turnaround in the second quarter of 2015 and the coker expansion tie-in during the third quarter of 2014. Third quarter 2015 production of SCO exceeded the Company's previously issued guidance of 124,000 to 131,000 bbl/d. Fourth quarter 2015 production guidance targeted to average between 123,000 to 129,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2015 increased 38% to 21,915 bbl/d from 15,848 bbl/d for the nine months ended September 30, 2014. Third quarter 2015 crude oil production increased 23% to 22,387 bbl/d from 18,197 bbl/d for the third quarter of 2014, and increased 10% from 20,330 bbl/d for the second quarter of 2015. The increase in production for the three and nine months ended September 30, 2015 from the comparable periods in 2014 primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014. The increase in production for the third quarter of 2015 from the second quarter of 2015 was primarily due to the impact of planned turnarounds performed at the Ninian platforms.

Offshore Africa

Offshore Africa crude oil production increased 36% to 17,140 bbl/d for the nine months ended September 30, 2015 from 12,557 bbl/d for the nine months ended September 30, 2014. Third quarter 2015 crude oil production increased 54% to 21,077 bbl/d from 13,684 bbl/d for the third quarter of 2014 and increased 23% from 17,070 bbl/d for the second quarter of 2015. The increase in production volumes for the three and nine months ended September 30, 2015 from the comparable periods was due to new wells on stream at both the Espoir and the Baobab fields in the second and third quarters of 2015, partially offset by natural field declines.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2015 crude oil production was 43,464 bbl/d and was within the Company's previously issued guidance of 42,000 to 46,000 bbl/d. Fourth quarter 2015 production guidance is targeted to average between 51,000 and 55,000 bbl/d of crude oil.

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 storage facilities, pipelines, or FPSOs, as follows:

(bbl)	**Sep 30 2015**	Jun 30 2015	Dec 31 2014
North America – Exploration and Production	**424,270**	839,720	930,116
North America – Oil Sands Mining and Upgrading (SCO)	**1,327,603**	1,074,964	1,266,063
North Sea	**450,023**	131,959	368,808
Offshore Africa	**1,353,011**	1,459,094	461,997
	3,554,907	3,505,737	3,026,984

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 41.55**	$ 53.09	$ 79.99	**$ 43.58**	$ 82.35
Transportation	**2.56**	2.80	2.32	**2.60**	2.51
Realized sales price, net of transportation	**38.99**	50.29	77.67	**40.98**	79.84
Royalties	**4.09**	5.91	13.66	**4.57**	14.46
Production expense	**15.70**	17.01	15.99	**16.25**	18.08
Netback	**$ 19.20**	$ 27.37	$ 48.02	**$ 20.16**	$ 47.30
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.22**	$ 3.06	$ 4.54	**$ 3.22**	$ 5.03
Transportation	**0.39**	0.38	0.26	**0.38**	0.27
Realized sales price, net of transportation	**2.83**	2.68	4.28	**2.84**	4.76
Royalties	**0.11**	0.05	0.32	**0.09**	0.43
Production expense	**1.31**	1.39	1.45	**1.38**	1.52
Netback	**$ 1.41**	$ 1.24	$ 2.51	**$ 1.37**	$ 2.81
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 33.46**	$ 38.85	$ 59.56	**$ 34.22**	$ 62.38
Transportation	**2.56**	2.67	2.08	**2.56**	2.24
Realized sales price, net of transportation	**30.90**	36.18	57.48	**31.66**	60.14
Royalties	**2.81**	3.58	9.12	**3.01**	9.97
Production expense	**12.68**	13.39	13.15	**13.09**	14.68
Netback	**$ 15.41**	$ 19.21	$ 35.21	**$ 15.56**	$ 35.49

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 39.26**	$ 50.96	$ 78.38	**$ 41.42**	$ 80.09
North Sea	**$ 62.28**	$ 73.57	$ 113.08	**$ 67.38**	$ 120.76
Offshore Africa	**$ 65.31**	$ 74.84	$ 104.82	**$ 69.23**	$ 111.25
Company average	**$ 41.55**	$ 53.09	$ 79.99	**$ 43.58**	$ 82.35
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.99**	$ 2.80	$ 4.43	**$ 2.98**	$ 4.91
North Sea	**$ 9.44**	$ 9.54	$ 6.93	**$ 9.71**	$ 6.45
Offshore Africa	**$ 9.01**	$ 10.49	$ 11.73	**$ 10.34**	$ 12.05
Company average	**$ 3.22**	$ 3.06	$ 4.54	**$ 3.22**	$ 5.03
Company average ($/BOE) (1) (2)	**$ 33.46**	$ 38.85	$ 59.56	**$ 34.22**	$ 62.38

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

North America

North America realized crude oil prices decreased 48% to $41.42 per bbl for the nine months ended September 30, 2015 from $80.09 per bbl for the nine months ended September 30, 2014. North America realized crude oil prices averaged $39.26 per bbl for the third quarter of 2015, a decrease of 50% compared with $78.38 per bbl for the third quarter of 2014 and a decrease of 23% compared with $50.96 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2015 contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 39% to average $2.98 per Mcf for the nine months ended September 30, 2015 from $4.91 per Mcf for the nine months ended September 30, 2014. North America realized natural gas prices decreased 33% to average $2.99 per Mcf for the third quarter of 2015 compared with $4.43 per Mcf in the third quarter of 2014, and increased 7% compared with $2.80 per Mcf for the second quarter of 2015. In the third quarter of 2015, realized natural gas pricing was comparable with the second quarter of 2015. US natural gas production was comparable between the second and third quarters of 2015 with natural gas inventories growing slightly above normal levels. Realized natural gas prices were lower in the third quarter of 2015 than the third quarter of 2014 primarily due to lower than average storage levels in 2014 resulting from the colder than normal winter temperatures.

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

(Quarterly Average)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 40.88**	$ 51.80	$ 77.79
Pelican Lake heavy crude oil ($/bbl)	**$ 39.54**	$ 54.87	$ 81.52
Primary heavy crude oil ($/bbl)	**$ 39.97**	$ 53.85	$ 79.70
Bitumen (thermal oil) ($/bbl)	**$ 37.46**	$ 44.63	$ 75.81
Natural gas ($/Mcf)	**$ 2.99**	$ 2.80	$ 4.43

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

North Sea

North Sea realized crude oil prices decreased 44% to average $67.38 per bbl for the nine months ended September 30, 2015 from $120.76 per bbl for the nine months ended September 30, 2014. North Sea realized crude oil prices decreased 45% to average $62.28 per bbl for the third quarter of 2015 from $113.08 per bbl for the third quarter of 2014 and decreased 15% from $73.57 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 38% to average $69.23 per bbl for the nine months ended September 30, 2015 from $111.25 per bbl for the nine months ended September 30, 2014. Offshore Africa realized crude oil prices decreased 38% to average $65.31 per bbl for the third quarter of 2015 from $104.82 per bbl for the third quarter of 2014 and decreased 13% from $74.84 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 4.34**	$ 6.40	$ 13.99	**$ 4.86**	$ 15.17
North Sea	**$ 0.17**	$ 0.11	$ 0.84	**$ 0.14**	$ 0.43
Offshore Africa	**$ 2.89**	$ 3.19	$ 10.79	**$ 3.04**	$ 7.77
Company average	**$ 4.09**	$ 5.91	$ 13.66	**$ 4.57**	$ 14.46
Natural gas ($/Mcf) [1]					
North America	**$ 0.11**	$ 0.05	$ 0.30	**$ 0.09**	$ 0.41
Offshore Africa	**$ 0.41**	$ 0.48	$ 1.88	**$ 0.47**	$ 1.94
Company average	**$ 0.11**	$ 0.05	$ 0.32	**$ 0.09**	$ 0.43
Company average ($/BOE) [1]	**$ 2.81**	$ 3.58	$ 9.12	**$ 3.01**	$ 9.97

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

North America

North America crude oil and natural gas royalties for the three and nine months ended September 30, 2015 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the nine months ended September 30, 2015 compared with 20% of product sales for the nine months ended September 30, 2014. Crude oil and NGLs royalties averaged approximately 12% of product sales for the third quarter of 2015 compared with 18% for the third quarter of 2014 and 13% for the second quarter of 2015. The decrease in royalties for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to lower realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 11.5% to 13.5% of product sales for 2015.

Natural gas royalties averaged approximately 3% of product sales for the nine months ended September 30, 2015 compared with 9% of product sales for the nine months ended September 30, 2014. Natural gas royalties averaged approximately 4% of product sales for the third quarter of 2015 compared with 7% for the third quarter of 2014 and 2% for the second quarter of 2015. The decrease in natural gas royalty rates for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was due to lower realized natural gas prices. The increase in natural gas royalty rates for the third quarter of 2015 from the second quarter of 2015 was due to higher realized natural gas prices. Natural gas royalties are anticipated to average 3% to 4% of product sales for 2015.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 4% for the nine months ended September 30, 2015 compared with 9% for the nine months ended September 30, 2014. Royalty rates as a percentage of product sales averaged approximately 4% for the third quarter of 2015 compared with 11% for the third quarter of 2014 and 4% for the second quarter of 2015. The decrease in royalties for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was primarily a result of the timing of liftings from various fields and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 3.5% to 5.5% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2015	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.64**	$ 13.14	$ 14.52	**$ 12.85**	$ 15.20
North Sea	**$ 72.69**	$ 60.61	$ 76.48	**$ 65.64**	$ 77.31
Offshore Africa	**$ 40.53**	$ 43.88	$ 27.20	**$ 37.85**	$ 40.91
Company average	**$ 15.70**	$ 17.01	$ 15.99	**$ 16.25**	$ 18.08
Natural gas ($/Mcf) (1)					
North America	**$ 1.25**	$ 1.28	$ 1.36	**$ 1.30**	$ 1.45
North Sea	**$ 3.85**	$ 6.47	$ 19.21	**$ 4.80**	$ 10.58
Offshore Africa	**$ 1.43**	$ 1.42	$ 2.68	**$ 1.86**	$ 3.18
Company average	**$ 1.31**	$ 1.39	$ 1.45	**$ 1.38**	$ 1.52
Company average ($/BOE) (1)	**$ 12.68**	$ 13.39	$ 13.15	**$ 13.09**	$ 14.68

(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, 2015 decreased 15% to $12.85 per bbl from $15.20 per bbl for the nine months ended September 30, 2014. North America crude oil and NGLs production expense for the third quarter of 2015 decreased 20% to $11.64 per bbl from $14.52 per bbl for the third quarter of 2014 and decreased 11% from $13.14 per bbl for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods reflected the Company’s continuous focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America crude oil and NGLs production expense is now anticipated to average $12.25 to $13.25 per bbl for 2015.

North America natural gas production expense for the nine months ended September 30, 2015 decreased 10% to $1.30 per Mcf from $1.45 per Mcf for the nine months ended September 30, 2014. North America natural gas production expense for the third quarter of 2015 decreased 8% to $1.25 per Mcf from $1.36 per Mcf for the third quarter of 2014 and decreased 2% from $1.28 per Mcf for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods reflected the Company’s continuous focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America natural gas production expense is anticipated to average $1.25 to $1.35 per Mcf for 2015.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2015 decreased 15% to $65.64 per bbl from $77.31 per bbl for the nine months ended September 30, 2014. North Sea crude oil production expense for the third quarter of 2015 decreased 5% to $72.69 per bbl from $76.48 per bbl for the third quarter of 2014 and increased 20% from $60.61 per bbl for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was primarily due to higher production volumes on a relatively fixed cost structure, offset by the impact of the weaker Canadian dollar compared to 2014. The increase in production expense for the third quarter of 2015 from the second quarter of 2015 was primarily due to the timing of liftings from various fields, which have different cost structures, as well as the impact of the weaker Canadian dollar. North Sea crude oil production expense is anticipated to average $58.00 to $64.00 per bbl for 2015, reflecting the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2015 decreased 7% to $37.85 per bbl from $40.91 per bbl for the nine months ended September 30, 2014. Offshore Africa crude oil production expense for the third quarter of 2015 averaged $40.53 per bbl, an increase of 49% from $27.20 per bbl for the third quarter of 2014 and a decrease of 8% from $43.88 per bbl for the second quarter of 2015. The decrease in production expense for the nine months ended September 30, 2015 from the comparable period was primarily due to the impact of higher production volumes. The fluctuations in production expense for the three months ended September 30, 2015 from the comparable periods was primarily due to the timing of liftings from various fields, including Olowi, which have different cost structures, as well as the impact of the weaker Canadian dollar. Offshore Africa crude oil production expense is anticipated to average $24.00 to $28.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Expense ($ millions)	**$ 1,208**	$ 1,158	$ 1,087	**$ 3,579**	$ 3,065
$/BOE (1)	**$ 18.25**	$ 18.02	$ 16.54	**$ 18.02**	$ 17.08

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

Depletion, depreciation and amortization expense on a per barrel basis for the nine months ended September 30, 2015 increased 6% to $18.02 per BOE from $17.08 per BOE for the nine months ended September 30, 2014. Depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2015 increased 10% to $18.25 per BOE from $16.54 per BOE for the third quarter of 2014 and was comparable with the second quarter of 2015. The increase for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was primarily related to increased sales volumes in the International segments which have higher associated depletion rates.

The increase in depletion, depreciation and amortization expense for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the increase in sales volumes in 2015.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Expense ($ millions)	**$ 36**	$ 36	$ 37	**$ 107**	$ 109
$/BOE (1)	**$ 0.54**	$ 0.55	$ 0.56	**$ 0.54**	$ 0.60

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

Asset retirement obligation accretion expense on a per barrel basis for the nine months ended September 30, 2015 decreased 10% to $0.54 per BOE from $0.60 per BOE for the nine months ended September 30, 2014. Asset retirement obligation accretion expense for the third quarter of 2015 decreased 4% to $0.54 per BOE from $0.56 per BOE for the third quarter of 2014 and decreased 2% from $0.55 per BOE for the second quarter of 2015.

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

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the third quarter of 2015, operating performance continued to be strong, leading to average production of 131,779 bbl/d, reflecting high utilization rates and reliability.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($/bbl)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
SCO sales price (1)	**$ 60.66**	$ 73.05	$ 103.91	**$ 62.82**	$ 108.58
Bitumen value for royalty purposes (1) (2)	**$ 33.20**	$ 44.09	$ 74.11	**$ 34.92**	$ 72.03
Bitumen royalties (1) (3)	**$ 1.32**	$ 0.99	$ 7.17	**$ 1.11**	$ 6.29
Transportation	**$ 1.82**	$ 1.98	$ 2.28	**$ 1.87**	$ 1.88

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Calculated as the quarterly average of the bitumen valuation methodology price.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $62.82 per bbl for the nine months ended September 30, 2015, a decrease of 42% compared with $108.58 per bbl for the nine months ended September 30, 2014. Realized SCO sales prices averaged $60.66 per bbl for the third quarter of 2015, a decrease of 42% compared with $103.91 per bbl for the third quarter of 2014 and a decrease of 17% compared with $73.05 per bbl for the second quarter of 2015. The decrease for the three and nine months ended September 30, 2015 from the comparable periods reflected movements in benchmark pricing and the Canadian dollar.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Cash production costs	**$ 321**	$ 321	$ 398	**$ 988**	$ 1,214
Less: costs incurred during turnaround periods	**–**	(45)	(98)	**(45)**	(98)
Adjusted cash production costs	**$ 321**	$ 276	$ 300	**$ 943**	$ 1,116
Adjusted cash production costs, excluding natural gas costs	**$ 300**	$ 260	$ 280	**$ 886**	$ 1,027
Adjusted natural gas costs	**21**	16	20	**57**	89
Adjusted cash production costs	**$ 321**	$ 276	$ 300	**$ 943**	$ 1,116

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Adjusted cash production costs, excluding natural gas costs	**$ 25.28**	$ 27.52	$ 34.65	**$ 26.89**	$ 35.26
Adjusted natural gas costs	**1.76**	1.73	2.48	**1.74**	3.05
Adjusted cash production costs	**$ 27.04**	$ 29.25	$ 37.13	**$ 28.63**	$ 38.31
Sales (bbl/d)	**129,033**	103,388	87,826	**120,617**	106,721

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

Adjusted cash production costs for the nine months ended September 30, 2015 decreased 25% to $28.63 per bbl from $38.31 per bbl for the nine months ended September 30, 2014. Adjusted cash production costs for the third quarter of 2015 averaged $27.04 per bbl, a decrease of 27% compared with $37.13 per bbl for the third quarter of 2014 and a decrease of 8% compared with $29.25 per bbl for the second quarter of 2015. The decrease in adjusted cash production costs for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs. Cash production costs are now anticipated to average $29.00 to $32.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Depletion, depreciation and amortization	**$ 165**	$ 119	$ 137	**$ 423**	$ 402
Less: depreciation incurred during turnaround period	**–**	(5)	(28)	**(5)**	(28)
Adjusted depletion, depreciation and amortization	**$ 165**	$ 114	$ 109	**$ 418**	$ 374
$/bbl (1)	**$ 13.95**	$ 12.04	$ 13.43	**$ 12.70**	$ 12.83

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the nine months ended September 30, 2015 decreased 1% to $12.70 per bbl from $12.83 per bbl for the nine months ended September 30, 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2015 increased 4% to $13.95 per bbl from $13.43 per bbl for the third quarter of 2014 and increased 16% from $12.04 per bbl for the second quarter of 2015. The increase in the third quarter of 2015 reflected the impact of minor asset derecognitions.

The increase in depletion, depreciation and amortization expense for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the increase in sales volumes in 2015 and the impact of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Expense	**$ 8**	$ 7	$ 12	**$ 23**	$ 35
$/bbl (1)	**$ 0.65**	$ 0.82	$ 1.45	**$ 0.70**	$ 1.21

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

Asset retirement obligation accretion expense on a per barrel basis for the nine months ended September 30, 2015 decreased 42% to $0.70 per bbl from $1.21 per bbl for the nine months ended September 30, 2014. Asset retirement obligation accretion expense for the third quarter of 2015 decreased 55% to $0.65 per bbl from $1.45 per bbl for the third quarter of 2014 and decreased 21% from $0.82 per bbl for the second quarter of 2015.

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

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2015	Jun 30 2015	Sep 30 2014	Nine Months Ended Sep 30 2015	Sep 30 2014
Revenue	**$ 33**	$ 35	$ 30	**$ 103**	$ 91
Production expense	**7**	9	8	**25**	27
Midstream cash flow	**26**	26	22	**78**	64
Depreciation	**3**	3	2	**9**	7
Equity loss (gain) from investment	**20**	(3)	5	**32**	3
Segment earnings before taxes	**$ 3**	$ 26	$ 15	**$ 37**	$ 54

Midstream operating results were consistent with the comparable periods.

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The Company, along with APMC, have each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. During the third quarter of 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044. As at September 30, 2015, Redwater Partnership had borrowings of $788 million under its secured $3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Sep 30 2015	Jun 30 2015	Sep 30 2014	Nine Months Ended Sep 30 2015	Sep 30 2014
Expense	**$ 93**	$ 100	$ 87	**$ 297**	$ 267
$/BOE (1)	**$ 1.20**	$ 1.35	$ 1.17	**$ 1.28**	$ 1.28

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

Administration expense on a per BOE basis for the nine months ended September 30, 2015 was comparable with the nine months ended September 30, 2014. Administration expense for the third quarter of 2015 increased 3% to $1.20 per BOE from $1.17 per BOE for the third quarter of 2014 and decreased 11% from $1.35 per BOE for the second quarter of 2015. Administration expense per BOE decreased for the third quarter of 2015 from the second quarter of 2015 primarily due to lower staffing related costs and general corporate costs as well as the impact of higher sales volumes.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2015	Three Months Ended Jun 30 2015	Three Months Ended Sep 30 2014	Nine Months Ended Sep 30 2015	Nine Months Ended Sep 30 2014
(Recovery) Expense	**$ (87)**	$ (79)	$ (122)	**$ (102)**	$ 210

The Company's stock option plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $102 million share-based compensation recovery for the nine months ended September 30, 2015, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. For the nine months ended September 30, 2015, the Company recovered $22 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (September 30, 2014 – $42 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Sep 30 2015	Three Months Ended Jun 30 2015	Three Months Ended Sep 30 2014	Nine Months Ended Sep 30 2015	Nine Months Ended Sep 30 2014
Expense, gross	**$ 142**	$ 147	$ 135	**$ 433**	$ 386
Less: capitalized interest	**64**	62	56	**184**	147
Expense, net	**$ 78**	$ 85	$ 79	**$ 249**	$ 239
$/BOE (1)	**$ 1.00**	$ 1.16	$ 1.06	**$ 1.08**	$ 1.15
Average effective interest rate	**3.8%**	3.8%	3.9%	**3.9%**	4.0%

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

Net interest and other financing expense on a per barrel basis for the nine months ended September 30, 2015 decreased 6% to $1.08 per BOE from $1.15 per BOE for the nine months ended September 30, 2014. Net interest and other financing expense on a per barrel basis for the third quarter of 2015 decreased 6% to $1.00 per BOE from $1.06 per BOE for the third quarter of 2014 and decreased 14% from $1.16 per BOE for the second quarter of 2015. The decrease for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to increased sales volumes, interest received on North Sea tax refunds, and the impact of higher capitalized interest.

Gross interest and other financing expense for the three and nine months ended September 30, 2015 increased from the comparable periods in 2014 primarily due to the impact of higher overall debt levels. Capitalized interest of $184 million for the nine months ended September 30, 2015 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the three and nine months ended September 30, 2015 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Crude oil and NGLs financial instruments	**$ (173)**	$ (91)	$ –	**$ (381)**	$ –
Natural gas financial instruments	**–**	–	21	**–**	33
Foreign currency contracts	**(90)**	22	(17)	**(207)**	(47)
Realized (gain) loss	**(263)**	(69)	4	**(588)**	(14)
Crude oil and NGLs financial instruments	**(12)**	205	(70)	**205**	(24)
Natural gas financial instruments	**–**	–	(21)	**–**	–
Foreign currency contracts	**(17)**	10	(59)	**(5)**	(23)
Unrealized (gain) loss	**(29)**	215	(150)	**200**	(47)
Net (gain) loss	**$ (292)**	$ 146	$ (146)	**$ (388)**	$ (61)

During the nine months ended September 30, 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company also recorded a net unrealized loss of $200 million ($147 million after-tax) on its risk management activities for the nine months ended September 30, 2015, including an unrealized gain of $29 million ($24 million after-tax) for the third quarter of 2015 (June 30, 2015 – unrealized loss of $215 million; $162 million after-tax; September 30, 2014 – unrealized gain of $150 million; $118 million after-tax).

Complete details related to outstanding derivative financial instruments at September 30, 2015 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Net realized (gain) loss	**$ (28)**	$ (11)	$ (1)	**$ (92)**	$ 29
Net unrealized loss (gain) (1)	**351**	(76)	185	**688**	150
Net loss (gain)	**$ 323**	$ (87)	$ 184	**$ 596**	$ 179

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

The net realized foreign exchange gain for the nine months ended September 30, 2015 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange loss for the nine months ended September 30, 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2015 – unrealized gain of $267 million, June 30, 2015 – unrealized loss of $61 million, September 30, 2014 – unrealized gain of $153 million; nine months ended September 30, 2015 – unrealized gain of $520 million, September 30, 2014 – unrealized gain of $144 million). The US/Canadian dollar exchange rate at September 30, 2015 was US$0.7466 (June 30, 2015 – US$0.8017, December 31, 2014 – US$0.8620; September 30, 2014 – US$0.8922).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2015	Jun 30 2015	Sep 30 2014	Nine Months Ended Sep 30 2015	Sep 30 2014
North America [1]	**$ 65**	$ 79	$ 162	**$ 152**	$ 579
North Sea	**(16)**	(19)	14	**(99)**	(45)
Offshore Africa	**5**	5	21	**12**	35
PRT recovery – North Sea	**(61)**	(72)	(114)	**(187)**	(187)
Other taxes	**2**	4	6	**9**	18
Current income tax (recovery) expense	**(5)**	(3)	89	**(113)**	400
Deferred income tax expense	**8**	498	158	**217**	427
Deferred PRT expense – North Sea	**10**	30	50	**47**	127
Deferred income tax expense	**18**	528	208	**264**	554
	$ 13	$ 525	$ 297	**$ 151**	$ 954
Income tax rate and other legislative changes [2] [3]	**–**	(579)	–	**(351)**	–
	$ 13	$ (54)	$ 297	**$ (200)**	$ 954
Effective income tax rate on adjusted net earnings from operations [4]	**28.0%**	17.0%	24.7%	**10.3%**	24.4%

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

(2) During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million.

(3) During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

(4) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The current PRT recovery in the North Sea in the third quarter of 2015 and the comparative quarters reflects the impact of abandonment expenditures on the Murchison platform.

The effective income tax rate for the three and nine months ended September 30, 2015 included the impact of non-taxable items in North America and the North Sea as well as the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings.

In June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the income tax changes, the Company's deferred income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

For 2015, based on forward commodity prices and the current availability of tax pools, the Company now expects to incur current income tax expense of $150 million to $200 million in Canada and recoveries of $285 million to $335 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2015	Three Months Ended Jun 30 2015	Three Months Ended Sep 30 2014	Nine Months Ended Sep 30 2015	Nine Months Ended Sep 30 2014
Exploration and Evaluation					
Net expenditures [2] [3]	**$ 5**	$ 29	$ 92	**$ 80**	$ 1,093
Property, Plant and Equipment					
Net property acquisitions [2] [3]	**(70)**	51	79	**(8)**	2,821
Well drilling, completion and equipping	**237**	199	498	**728**	1,580
Production and related facilities	**191**	249	504	**754**	1,348
Capitalized interest and other [4]	**23**	27	34	**76**	78
Net expenditures	**381**	526	1,115	**1,550**	5,827
Total Exploration and Production	**386**	555	1,207	**1,630**	6,920
Oil Sands Mining and Upgrading					
Horizon Phase 2/3 construction costs	**668**	535	670	**1,609**	1,763
Sustaining capital	**64**	94	122	**246**	269
Turnaround costs	**3**	6	15	**13**	21
Capitalized interest and other [4]	**42**	43	38	**156**	195
Total Oil Sands Mining and Upgrading	**777**	678	845	**2,024**	2,248
Midstream	**2**	1	27	**6**	78
Abandonments [4]	**65**	56	82	**265**	245
Head office	**10**	7	14	**24**	33
Total net capital expenditures	**$ 1,240**	$ 1,297	$ 2,175	**$ 3,949**	$ 9,524
By segment					
North America [2] [3]	**$ 199**	$ 307	$ 997	**$ 1,007**	$ 6,471
North Sea	**41**	93	100	**196**	295
Offshore Africa	**146**	155	110	**427**	154
Oil Sands Mining and Upgrading	**777**	678	845	**2,024**	2,248
Midstream	**2**	1	27	**6**	78
Abandonments [5]	**65**	56	82	**265**	245
Head office	**10**	7	14	**24**	33
Total	**$ 1,240**	$ 1,297	$ 2,175	**$ 3,949**	$ 9,524

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of properties.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) 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 areas. 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 owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Previously in 2015, the Company reduced its annual capital expenditure guidance by approximately $3,100 million. In November 2015, the Company further exercised its capital flexibility and announced that it would reduce annual capital spending guidance by an additional $65 million.

Net capital expenditures for the nine months ended September 30, 2015 were $3,949 million compared with $9,524 million for the nine months ended September 30, 2014. Net capital expenditures for the third quarter of 2015 were $1,240 million compared with $2,175 million for the third quarter of 2014 and $1,297 million for the second quarter of 2015. The capital expenditures for the three and nine months ended September 30, 2015 reflected the Company's previously announced reduction in its capital program, as well as its capital allocation strategy, including the planned drilling activities in Offshore Africa.

Drilling Activity

	Three Months Ended			Nine Months Ended	
(number of wells)	**Sep 30 2015**	Jun 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Net successful natural gas wells	**4**	2	21	**15**	59
Net successful crude oil wells (1)	**66**	5	273	**113**	698
Dry wells	**4**	–	6	**6**	11
Stratigraphic test / service wells	**1**	6	11	**93**	363
Total	**75**	13	311	**227**	1,131
Success rate (excluding stratigraphic test / service wells)	**95%**	100%	98%	**96%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 28% of the total capital expenditures for the nine months ended September 30, 2015 compared with approximately 70% for the nine months ended September 30, 2014.

During the third quarter of 2015, the Company targeted 4 net natural gas wells, including 2 wells in Northwest Alberta, 1 well in Northeast British Columbia and 1 well in Northern Plains. The Company also targeted 67 net primary heavy crude oil wells in the Company's Northern Plains region.

Overall thermal oil production for the third quarter of 2015 averaged approximately 133,200 bbl/d compared with approximately 115,300 bbl/d for the third quarter of 2014 and approximately 105,000 bbl/d for the second quarter of 2015. Production volumes in the third quarter of 2015 reflected the reinstatement of production after the forest fires in Northeastern Alberta, together with the cyclic nature of thermal oil production at Primrose.

Development of the tertiary recovery conversion projects at Pelican Lake continued. Pelican Lake production averaged approximately 50,900 bbl/d for the third quarter of 2015 compared with 51,900 bbl/d for the third quarter of 2014 and 52,000 bbl/d for the second quarter of 2015.

In order to expand its pipeline infrastructure, the Company is participating in the expansion of the Cold Lake pipeline system. Initial pipeline commissioning activities commenced in the first quarter of 2015 with the final phases of the project expected to continue for approximately three years.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the third quarter of 2015 continued to focused on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, sour water concentrator, combined hydrotreater and sulphur recovery units.

Targeted annual capital spending in 2015 was further revised from $2,200 million to $2,150 million during the second quarter of 2015 through targeted cost efficiencies, while maintaining planned expansion activities.

North Sea

During 2015, the Company completed one injection well and no further development activities are planned. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

Offshore Africa

During 2015, at the Espoir field, Côte d'Ivoire, the Company drilled 5 gross wells, adding net production volumes of approximately 5,300 bbl/d to date. The infill drilling program is currently tracking to below its original sanction costs for the 10 gross well program (5.9 net well program).

During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 3 gross wells, adding net production volumes of approximately 6,300 bbl/d to date. Production from the fourth gross well is targeted to come on stream in the fourth quarter of 2015. The drilling program is currently tracking to below its original sanction costs for the 6 gross well drilling program (3.4 net well program).

In Block CI-514, the Company has a 36% non-operated interest. In the second quarter of 2014, the operator completed drilling the first exploratory well and encountered the presence of light oil. As a follow-up, in April 2015, a second exploratory well was drilled to evaluate the potential of the initial well. The second exploratory well has been plugged and abandoned, and the results will be evaluated and integrated into the Company's understanding of the block.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2015**	Jun 30 2015	Dec 31 2014	Sep 30 2014
Working capital (deficit) (1)	**$ 309**	$ 261	$ (673)	$ (915)
Long-term debt (2) (3)	**$ 16,510**	$ 15,983	$ 14,002	$ 13,685
Share capital	**$ 4,533**	$ 4,532	$ 4,432	$ 4,388
Retained earnings	**22,885**	23,248	24,408	23,499
Accumulated other comprehensive income (loss)	**67**	(7)	51	47
Shareholders' equity	**$ 27,485**	$ 27,773	$ 28,891	$ 27,934
Debt to book capitalization (3) (4)	**38%**	37%	33%	33%
Debt to market capitalization (3) (5)	**37%**	30%	26%	22%
After-tax return on average common shareholders' equity (6)	**2%**	6%	14%	12%
After-tax return on average capital employed (3) (7)	**2%**	4%	10%	9%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt.
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums, and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.
(7) Calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the period.

At September 30, 2015, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2014. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is dependent upon 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 ongoing 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.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the decline in commodity prices, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - Subsequent to September 30, 2015, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2017. If issued, these securities may be offered separately or together, in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

  - During the second quarter of 2015, the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes. In addition, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. As a result, the Company's available liquidity increased by $350 million;
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program;
  - During the first quarter of 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at September 30, 2015;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. All of the Company's credit facilities are subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

During the second quarter of 2015, the Company repaid $400 million of 4.95% medium term notes.

As at September 30, 2015, the Company had in place bank credit facilities of $7,480 million, of which $3,440 million, net of commercial paper issuances of $669 million, was available for general corporate purposes.

At September 30, 2015, the Company had long-term debt with a carrying amount of $1,004 million maturing over the next 12 months (US$500 million of three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% due August 2016). These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.

Long-term debt was $16,510 million at September 30, 2015, resulting in a debt to book capitalization ratio of 38% (December 31, 2014 – 33%; September 30, 2014 – 33%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its production for 2015 at prices that protect investment returns to support 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, 2015 are discussed in note 6 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy 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 policy, the purchase of put options is in addition to the above parameters. As at November 3, 2015, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using price collars for the remainder of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2015 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2015, there were 1,094,408,000 common shares outstanding (December 31, 2014 – 1,091,837,000 common shares) and 67,308,000 stock options outstanding. As at November 3, 2015, the Company had 1,094,450,000 common shares outstanding and 67,118,000 stock options outstanding.

On March 4, 2015, the Board of Directors approved an increase in the annual dividend to $0.92 per common share, (previous annual dividend rate of $0.90 per common share), beginning with the quarterly dividend payable on April 1, 2015, at $0.23 per common share. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

In April 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the nine months ended September 30, 2015, the Company did not purchase any common shares for cancellation.

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. The following table summarizes the Company's commitments as at September 30, 2015:

($ millions)	Remaining 2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 110	$ 381	$ 337	$ 295	$ 256	$ 1,542
Offshore equipment operating leases and offshore drilling	$ 119	$ 174	$ 90	$ 68	$ 22	$ –
Long-term debt (1) (3)	$ 669	$ 1,005	$ 2,472	$ 2,842	$ 1,369	$ 8,229
Interest and other financing expense (2)	$ 122	$ 633	$ 551	$ 467	$ 427	$ 4,858
Office leases	$ 10	$ 41	$ 42	$ 43	$ 43	$ 239
Other	$ 54	$ 131	$ 65	$ 36	$ –	$ –

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.

(2) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest 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, 2015.

(3) At September 30, 2015, the Company had US$500 million of three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% due August 2016. These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. 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.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2014.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgments in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2015**	Dec 31 2014
ASSETS			
Current assets			
Cash and cash equivalents		**$ 30**	$ 25
Accounts receivable		**1,314**	1,889
Current income taxes		**599**	228
Inventory		**663**	665
Prepaids and other		**270**	172
Current portion of other long-term assets	5	**468**	510
		3,344	3,489
Exploration and evaluation assets	3	**3,437**	3,557
Property, plant and equipment	4	**52,830**	52,480
Other long-term assets	5	**1,017**	674
		$ 60,628	$ 60,200
LIABILITIES			
Current liabilities			
Accounts payable		**$ 470**	$ 564
Accrued liabilities		**2,398**	3,279
Current portion of long-term debt	6	**1,673**	980
Current portion of other long-term liabilities	7	**167**	319
		4,708	5,142
Long-term debt	6	**14,837**	13,022
Other long-term liabilities	7	**4,243**	4,175
Deferred income taxes		**9,355**	8,970
		33,143	31,309
SHAREHOLDERS' EQUITY			
Share capital	9	**4,533**	4,432
Retained earnings		**22,885**	24,408
Accumulated other comprehensive income	10	**67**	51
		27,485	28,891
		$ 60,628	$ 60,200

Commitments and contingencies (note 14).

Approved by the Board of Directors on November 3, 2015

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Sep 30 2015**	Three Months Ended Sep 30 2014	Nine Months Ended **Sep 30 2015**	Nine Months Ended Sep 30 2014
Product sales		**$ 3,316**	$ 5,370	**$ 10,204**	$ 16,451
Less: royalties		**(202)**	(658)	**(634)**	(1,972)
Revenue		**3,114**	4,712	**9,570**	14,479
Expenses					
Production		**1,166**	1,267	**3,607**	3,866
Transportation and blending		**540**	747	**1,804**	2,473
Depletion, depreciation and amortization	4	**1,376**	1,226	**4,011**	3,474
Administration		**93**	87	**297**	267
Share-based compensation	7	**(87)**	(122)	**(102)**	210
Asset retirement obligation accretion	7	**44**	49	**130**	144
Interest and other financing expense		**78**	79	**249**	239
Risk management activities	13	**(292)**	(146)	**(388)**	(61)
Foreign exchange loss		**323**	184	**596**	179
Gain on disposition of properties	4	**(49)**	–	**(49)**	–
Equity loss from investment	5	**20**	5	**32**	3
		3,212	3,376	**10,187**	10,794
Earnings (loss) before taxes		**(98)**	1,336	**(617)**	3,685
Current income tax (recovery) expense	8	**(5)**	89	**(113)**	400
Deferred income tax expense	8	**18**	208	**264**	554
Net earnings (loss)		**$ (111)**	$ 1,039	**$ (768)**	$ 2,731
Net earnings (loss) per common share					
Basic	12	**$ (0.10)**	$ 0.95	**$ (0.70)**	$ 2.50
Diluted	12	**$ (0.10)**	$ 0.94	**$ (0.70)**	$ 2.49

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2015**	Three Months Ended Sep 30 2014	Nine Months Ended **Sep 30 2015**	Nine Months Ended Sep 30 2014
Net earnings (loss)	**$ (111)**	$ 1,039	**$ (768)**	$ 2,731
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $5 million (2014 – $nil) – three months ended; $1 million (2014 – $nil) – nine months ended	**35**	(2)	**(8)**	(1)
Reclassification to net earnings (loss), net of taxes of $nil (2014 – $1 million) – three months ended; $1 million (2014 – $1 million) – nine months ended	**(5)**	3	**(11)**	7
	30	1	**(19)**	6
Foreign currency translation adjustment				
Translation of net investment	**44**	–	**35**	(1)
Other comprehensive income, net of taxes	**74**	1	**16**	5
Comprehensive income (loss)	**$ (37)**	$ 1,040	**$ (752)**	$ 2,736

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2015	Nine Months Ended Sep 30 2014
Share capital	9		
Balance – beginning of period		**$ 4,432**	$ 3,854
Issued upon exercise of stock options		**84**	448
Previously recognized liability on stock options exercised for common shares		**17**	120
Purchase of common shares under Normal Course Issuer Bid		**–**	(34)
Balance – end of period		**4,533**	4,388
Retained earnings			
Balance – beginning of period		**24,408**	21,876
Net earnings (loss)		**(768)**	2,731
Purchase of common shares under Normal Course Issuer Bid	9	**–**	(370)
Dividends on common shares	9	**(755)**	(738)
Balance – end of period		**22,885**	23,499
Accumulated other comprehensive income	10		
Balance – beginning of period		**51**	42
Other comprehensive income, net of taxes		**16**	5
Balance – end of period		**67**	47
Shareholders' equity		**$ 27,485**	$ 27,934

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2015**	Three Months Ended Sep 30 2014	Nine Months Ended **Sep 30 2015**	Nine Months Ended Sep 30 2014
Operating activities				
Net earnings (loss)	**$ (111)**	$ 1,039	**$ (768)**	$ 2,731
Non-cash items				
Depletion, depreciation and amortization	**1,376**	1,226	**4,011**	3,474
Share-based compensation	**(87)**	(122)	**(102)**	210
Asset retirement obligation accretion	**44**	49	**130**	144
Unrealized risk management (gain) loss	**(29)**	(150)	**200**	(47)
Unrealized foreign exchange loss	**351**	185	**688**	150
Equity loss from investment	**20**	5	**32**	3
Deferred income tax expense	**18**	208	**264**	554
Gain on disposition of properties	**(49)**	–	**(49)**	–
Other	**19**	18	**81**	69
Abandonment expenditures	**(65)**	(82)	**(265)**	(245)
Net change in non-cash working capital	**121**	(45)	**(75)**	(902)
	1,608	2,331	**4,147**	6,141
Financing activities				
(Repayment) issue of bank credit facilities and commercial paper, net	**(168)**	(151)	**1,043**	1,557
Issue of medium-term notes, net	**–**	–	**107**	992
Issue of US dollar debt securities, net	**–**	–	**–**	1,100
Issue of common shares on exercise of stock options	**1**	63	**84**	448
Purchase of common shares under Normal Course Issuer Bid	**–**	(163)	**–**	(404)
Dividends on common shares	**(252)**	(246)	**(748)**	(709)
Net change in non-cash working capital	**–**	(5)	**(40)**	(16)
	(419)	(502)	**446**	2,968
Investing activities				
Net expenditures on exploration and evaluation assets	**(5)**	(92)	**(80)**	(1,093)
Net expenditures on property, plant and equipment	**(1,170)**	(2,001)	**(3,604)**	(8,186)
Investment in other long-term assets	**–**	–	**(112)**	(113)
Net change in non-cash working capital	**(16)**	249	**(792)**	283
	(1,191)	(1,844)	**(4,588)**	(9,109)
(Decrease) increase in cash and cash equivalents	**(2)**	(15)	**5**	–
Cash and cash equivalents – beginning of period	**32**	31	**25**	16
Cash and cash equivalents – end of period	**$ 30**	$ 16	**$ 30**	$ 16
Interest paid	**$ 172**	$ 142	**$ 447**	$ 387
Income taxes (received) paid	**$ (128)**	$ 63	**$ 136**	$ 665

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855-2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2014. These 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 consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2014.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In July 2015, the IASB approved an amendment to IFRS 15 "Revenue from Contracts with Customers" to defer the effective date of the new standard by one year to January 1, 2018.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2014	$ 3,426	$ –	$ 131	$ –	$ 3,557
Additions, net	**63**	**–**	**28**	**–**	**91**
Transfers to property, plant and equipment	**(223)**	**–**	**–**	**–**	**(223)**
Foreign exchange adjustments	**–**	**–**	**12**	**–**	**12**
At September 30, 2015	**$ 3,266**	**$ –**	**$ 171**	**$ –**	**$ 3,437**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2014	$ 60,606	$ 6,182	$ 3,858	$ 21,948	$ 570	$ 352	$ 93,516
Additions	**1,115**	**193**	**399**	**2,024**	**6**	**24**	**3,761**
Transfers from E&E assets	**223**	**–**	**–**	**–**	**–**	**–**	**223**
Disposals/derecognitions	**(460)**	**–**	**–**	**(86)**	**–**	**–**	**(546)**
Foreign exchange adjustments and other	**–**	**973**	**624**	**–**	**–**	**–**	**1,597**
At September 30, 2015	**$ 61,484**	**$ 7,348**	**$ 4,881**	**$ 23,886**	**$ 576**	**$ 376**	**$ 98,551**
Accumulated depletion and depreciation							
At December 31, 2014	$ 31,886	$ 4,049	$ 2,890	$ 1,864	$ 120	$ 227	$ 41,036
Expense	**3,167**	**278**	**115**	**423**	**9**	**19**	**4,011**
Disposals/derecognitions	**(374)**	**–**	**–**	**(86)**	**–**	**–**	**(460)**
Foreign exchange adjustments and other	**(3)**	**660**	**477**	**–**	**–**	**–**	**1,134**
At September 30, 2015	**$ 34,676**	**$ 4,987**	**$ 3,482**	**$ 2,201**	**$ 129**	**$ 246**	**$ 45,721**
Net book value							
– at September 30, 2015	**$ 26,808**	**$ 2,361**	**$ 1,399**	**$ 21,685**	**$ 447**	**$ 130**	**$ 52,830**
– at December 31, 2014	$ 28,720	$ 2,133	$ 968	$ 20,084	$ 450	$ 125	$ 52,480

Project costs not subject to depletion and depreciation	**Sep 30 2015**	Dec 31 2014
Horizon	**$ 7,010**	$ 5,492
Kirby Thermal Oil Sands – North	**$ 777**	$ 681

During the nine months ended September 30, 2015, the Company acquired a number of crude oil and natural gas properties, including exploration and evaluation assets in the North America Exploration and Production segment, for net cash consideration of $206 million, together with associated asset retirement obligations of $34 million. No debt obligations were assumed and no net deferred tax liabilities were recognized. In addition, the Company disposed of a number of North America crude oil and natural gas properties, including exploration and evaluation assets of $3 million, for proceeds of $134 million, together with associated asset retirement obligations of $4 million, resulting in a pre-tax gain on sale of properties of $49 million.

As at September 30, 2015 the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the nine months ended September 30, 2015, pre-tax interest of $184 million (September 30, 2014 – $147 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (September 30, 2014 – 4.0%).

5. OTHER LONG-TERM ASSETS

		Sep 30 2015		Dec 31 2014
Investment in North West Redwater Partnership	$	266	$	298
North West Redwater Partnership subordinated debt (1)		248		120
Risk Management (note 13)		900		599
Other		71		167
		1,485		1,184
Less: current portion		468		510
	$	1,017	$	674

(1) Includes accrued interest.

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for using the equity method. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

The Company, along with APMC, have each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During the first quarter of 2015, the Company and APMC each provided an additional $112 million of subordinated debt (year ended December 31, 2014 - $113 million). Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. During the third quarter of 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044. As at September 30, 2015, Redwater Partnership had borrowings of $788 million under its secured $3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

6. LONG-TERM DEBT

		Sep 30 2015		Dec 31 2014
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,845**	$	2,404
Medium-term notes		**2,500**		2,400
		5,345		4,804
US dollar denominated debt, unsecured				
Bank credit facilities (September 30, 2015 – US$393 million; December 31, 2014 – $nil)		**526**		–
Commercial paper (US$500 million)		**669**		580
US dollar debt securities (US$7,500 million)		**10,046**		8,701
		11,241		9,281
Long-term debt before transaction costs and original issue discounts, net		**16,586**		14,085
Less: original issue discounts, net (1)		**(10)**		(21)
transaction costs (1) (2)		**(66)**		(62)
		16,510		14,002
Less: current portion of commercial paper		**669**		580
current portion of long-term debt (1) (2)		**1,004**		400
	$	**14,837**	$	13,022

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

(2) 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 and Commercial Paper

As at September 30, 2015, the Company had in place bank credit facilities of $7,480 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing January 2017;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- a $2,425 million revolving syndicated credit facility maturing June 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2020; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2015, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. Each of the $2,425 million revolving facilities is extendible annually 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 may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

Borrowings under the $1,000 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at September 30, 2015, the $1,000 million facility was fully drawn. Borrowings under the $1,500 million non-revolving term facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at September 30, 2015, the $1,500 million facility was fully drawn.

All of the Company's credit facilities are subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at September 30, 2015 was 1.6% (September 30, 2014 – 2.1%), and on long-term debt outstanding for the nine months ended September 30, 2015 was 3.9% (September 30, 2014 – 4.0%).

At September 30, 2015 letters of credit and guarantees aggregating $371 million, including a $39 million financial guarantee related to Horizon and $201 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

During the second quarter of 2015 the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes and repaid $400 million of 4.95% medium-term notes.

Subsequent to September 30, 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

Subsequent to September 30, 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

7. OTHER LONG-TERM LIABILITIES

	Sep 30 2015	Dec 31 2014
Asset retirement obligations	$ 4,327	$ 4,221
Share-based compensation	61	203
Other	22	70
	4,410	4,494
Less: current portion	167	319
	$ 4,243	$ 4,175

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (December 31, 2014 – 4.6%). A reconciliation of the discounted asset retirement obligations was as follows:

		Sep 30 2015		Dec 31 2014
Balance – beginning of period	**$**	**4,221**	$	4,162
Liabilities incurred		**6**		41
Liabilities acquired, net		**30**		404
Liabilities settled		**(265)**		(346)
Asset retirement obligation accretion		**130**		193
Revision of cost, inflation rates and timing estimates		**–**		(907)
Change in discount rate		**–**		558
Foreign exchange adjustments		**205**		116
Balance – end of period		**4,327**		4,221
Less: current portion		**127**		121
	$	**4,200**	$	4,100

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

		Sep 30 2015		Dec 31 2014
Balance – beginning of period	**$**	**203**	$	260
Share-based compensation (recovery) expense		**(102)**		66
Cash payment for stock options surrendered		**(1)**		(8)
Transferred to common shares		**(17)**		(129)
(Recovered from) capitalized to Oil Sands Mining and Upgrading		**(22)**		14
Balance – end of period		**61**		203
Less: current portion		**40**		158
	$	**21**	$	45

8. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Current corporate income tax expense – North America	**$ 65**	$ 162	**$ 152**	$ 579
Current corporate income tax (recovery) expense – North Sea	**(16)**	14	**(99)**	(45)
Current corporate income tax expense – Offshore Africa	**5**	21	**12**	35
Current PRT (1) recovery – North Sea	**(61)**	(114)	**(187)**	(187)
Other taxes	**2**	6	**9**	18
Current income tax (recovery) expense	**(5)**	89	**(113)**	400
Deferred corporate income tax expense	**8**	158	**217**	427
Deferred PRT (1) expense – North Sea	**10**	50	**47**	127
Deferred income tax expense	**18**	208	**264**	554
Income tax expense	**$ 13**	$ 297	**$ 151**	$ 954

(1) Petroleum Revenue Tax.

In June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes are still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of these income tax changes, the Company's deferred income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

9. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Nine Months Ended Sep 30, 2015	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,091,837**	**$ 4,432**
Issued upon exercise of stock options	**2,571**	**84**
Previously recognized liability on stock options exercised for common shares	**–**	**17**
Balance – end of period	**1,094,408**	**$ 4,533**

Dividend Policy

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 4, 2015, the Board of Directors approved the regular quarterly dividend at $0.23 per common share, an increase from the previous quarterly dividend of $0.225 per common share, which was approved on March 5, 2014.

Normal Course Issuer Bid

In April 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the nine months ended September 30, 2015, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2015:

	Nine Months Ended Sep 30, 2015		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**71,708**	**$**	**35.60**
Granted	**5,120**	**$**	**33.16**
Surrendered for cash settlement	**(172)**	**$**	**33.43**
Exercised for common shares	**(2,571)**	**$**	**32.71**
Forfeited	**(6,777)**	**$**	**35.12**
Outstanding – end of period	**67,308**	**$**	**35.58**
Exercisable – end of period	**20,610**	**$**	**36.59**

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Sep 30 2015		Sep 30 2014
Derivative financial instruments designated as cash flow hedges	**$**	**75**	$	87
Foreign currency translation adjustment		**(8)**		(40)
	$	**67**	$	47

11. 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 at 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 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 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or 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. At September 30, 2015, the ratio was within the target range at 38%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS 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 2015	Dec 31 2014
Long-term debt [1]	**$ 16,510**	$ 14,002
Total shareholders' equity	**$ 27,485**	$ 28,891
Debt to book capitalization	**38%**	33%

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

12. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Weighted average common shares outstanding – basic (thousands of shares)	**1,094,398**	1,092,149	**1,093,638**	1,091,864
Effect of dilutive stock options (thousands of shares) [1]	**–**	10,613	**–**	7,052
Weighted average common shares outstanding – diluted (thousands of shares)	**1,094,398**	1,102,762	**1,093,638**	1,098,916
Net earnings (loss)	**$ (111)**	$ 1,039	**$ (768)**	$ 2,731
Net earnings (loss) per common share – basic	**$ (0.10)**	$ 0.95	**$ (0.70)**	$ 2.50
– diluted	**$ (0.10)**	$ 0.94	**$ (0.70)**	$ 2.49

(1) For the three months ended September 30, 2015, the dilutive effect of 2,000 options has not been included in the determination of the weighted average number of common shares outstanding as the inclusion would be anti-dilutive to the net loss per common share (nine months ended September 30, 2015 – 1,127,000).

13. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Sep 30, 2015				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,314**	**$ –**	**$ –**	**$ –**	**$ 1,314**
Other long-term assets	**248**	**211**	**689**	**–**	**1,148**
Accounts payable	**–**	**–**	**–**	**(470)**	**(470)**
Accrued liabilities	**–**	**–**	**–**	**(2,398)**	**(2,398)**
Long-term debt (1)	**–**	**–**	**–**	**(16,510)**	**(16,510)**
	$ 1,562	**$ 211**	**$ 689**	**$ (19,378)**	**$ (16,916)**

	Dec 31, 2014				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,889	$ –	$ –	$ –	$ 1,889
Other long-term assets	120	415	184	–	719
Accounts payable	–	–	–	(564)	(564)
Accrued liabilities	–	–	–	(3,279)	(3,279)
Other long-term liabilities	–	–	–	(40)	(40)
Long-term debt (1)	–	–	–	(14,002)	(14,002)
	$ 2,009	$ 415	$ 184	$ (17,885)	$ (15,277)

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

The carrying amounts 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 recurring other long-term assets and fixed rate long-term debt are outlined below:

	Sep 30, 2015			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Other long-term assets (3)	**$ 1,148**	**$ –**	**$ 900**	**$ 248**
Fixed rate long-term debt (4) (5)	**$ (12,470)**	**$ (12,594)**	**$ –**	**$ –**

	Dec 31, 2014			
	Carrying amount	Fair value		
Asset (liability) (1) (2)		Level 1	Level 2	Level 3
Other long-term assets (3)	$ 719	$ –	$ 599	$ 120
Fixed rate long-term debt (4) (5)	$ (11,018)	$ (11,855)	$ –	$ –

(1) Excludes financial assets and liabilities where the carrying amount 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) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.

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

(5) Includes the current portion of fixed rate long-term debt.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)		**Sep 30, 2015**		Dec 31, 2014
Derivatives held for trading				
Crude oil price collars	**$**	**189**	$	410
Crude oil WCS [1] differential swaps		**–**		(16)
Foreign currency forward contracts		**22**		21
Cash flow hedges				
Foreign currency forward contracts		**12**		11
Cross currency swaps		**677**		173
	$	**900**	$	599
Included within:				
Current portion of other long-term assets	**$**	**427**	$	436
Other long-term assets		**473**		163
	$	**900**	$	599

(1) Western Canadian Select.

For the nine months ended September 30, 2015, the Company recognized a gain of $4 million (year ended December 31, 2014 – loss of $3 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 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 quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. 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.

Risk Management

The Company uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

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:

Asset (liability)		**Nine Months Ended Sep 30, 2015**		Year Ended Dec 31, 2014
Balance – beginning of period	**$**	**599**	$	(136)
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(200)**		451
Foreign exchange		**522**		270
Other comprehensive income (loss)		**(21)**		14
Balance – end of period		**900**		599
Less: current portion		**427**		436
	$	**473**	$	163

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2015	Sep 30 2014	**Sep 30 2015**	Sep 30 2014
Net realized risk management (gain) loss	**$ (263)**	$ 4	**$ (588)**	$ (14)
Net unrealized risk management (gain) loss	**(29)**	(150)	**200**	(47)
	$ (292)	$ (146)	**$ (388)**	$ (61)

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 periodically 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, 2015, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars	Oct 2015 – Dec 2015	50,000 bbl/d	US$80.00 – US$120.52	Brent

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.

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 periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. 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, 2015 the Company had no interest rate swap contracts outstanding.

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, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its 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, commercial paper 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, 2015, 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 2015	–	Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR (1) plus 0.309%
	Oct 2015	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2015	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2015	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2015	–	Mar 2038	US$550	1.170	6.25%	5.76%

(1) Canadian Dealer Offered Rate ("CDOR").

All cross currency swap derivative financial instruments were designated as hedges at September 30, 2015 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2015, the Company had US$2,075 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$893 million designated as cash flow hedges.

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, 2015, 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 nonperformance 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. At September 30, 2015, the Company had net risk management assets of $905 million with specific counterparties related to derivative financial instruments (December 31, 2014 – $622 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, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	470	$	–	$	–	$	–
Accrued liabilities	$	2,398	$	–	$	–	$	–
Long-term debt (1)	$	1,674	$	2,472	$	5,712	$	6,728

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		Remaining 2015		2016		2017		2018		2019		Thereafter
Product transportation and pipeline	$	110	$	381	$	337	$	295	$	256	$	1,542
Offshore equipment operating leases and offshore drilling	$	119	$	174	$	90	$	68	$	22	$	–
Office leases	$	10	$	41	$	42	$	43	$	43	$	239
Other	$	54	$	131	$	65	$	36	$	–	$	–

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. 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.

15. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	Exploration and Production															
	North America				North Sea				Offshore Africa				Total Exploration and Production			
	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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**2,273**	4,257	**7,252**	12,377	**152**	72	**505**	496	**156**	196	**334**	392	**2,581**	4,525	**8,091**	13,265
Less: royalties	**(179)**	(577)	**(581)**	(1,752)	**–**	(1)	**(1)**	(2)	**(7)**	(22)	**(15)**	(35)	**(186)**	(600)	**(597)**	(1,789)
Segmented revenue	**2,094**	3,680	**6,671**	10,625	**152**	71	**504**	494	**149**	174	**319**	357	**2,395**	3,925	**7,494**	11,476
Segmented expenses																
Production	**615**	755	**2,011**	2,170	**139**	59	**434**	325	**86**	50	**156**	138	**840**	864	**2,601**	2,633
Transportation and blending	**521**	746	**1,755**	2,471	**14**	–	**43**	3	**–**	1	**1**	1	**535**	747	**1,799**	2,475
Depletion, depreciation and amortization	**1,059**	1,020	**3,183**	2,842	**95**	26	**281**	149	**54**	41	**115**	74	**1,208**	1,087	**3,579**	3,065
Asset retirement obligation accretion	**23**	25	**70**	73	**10**	9	**29**	28	**3**	3	**8**	8	**36**	37	**107**	109
Realized risk management activities	**(263)**	4	**(588)**	(14)	**–**	–	**–**	–	**–**	–	**–**	–	**(263)**	4	**(588)**	(14)
Gain on disposition of properties	**(49)**	–	**(49)**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(49)**	–	**(49)**	–
Equity loss from investment	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Total segmented expenses	**1,906**	2,550	**6,382**	7,542	**258**	94	**787**	505	**143**	95	**280**	221	**2,307**	2,739	**7,449**	8,268
Segmented earnings (loss) before the following	**188**	1,130	**289**	3,083	**(106)**	(23)	**(283)**	(11)	**6**	79	**39**	136	**88**	1,186	**45**	3,208
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss																
Total non-segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax expense																
Net earnings (loss)																

(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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**722**	840	**2,071**	3,163	**33**	30	**103**	91	**(20)**	(25)	**(61)**	(68)	**3,316**	5,370	**10,204**	16,451
Less: royalties	**(16)**	(58)	**(37)**	(183)	**–**	–	**–**	–	**–**	–	**–**	–	**(202)**	(658)	**(634)**	(1,972)
Segmented revenue	**706**	782	**2,034**	2,980	**33**	30	**103**	91	**(20)**	(25)	**(61)**	(68)	**3,114**	4,712	**9,570**	14,479
Segmented expenses																
Production	**321**	398	**988**	1,214	**7**	8	**25**	27	**(2)**	(3)	**(7)**	(8)	**1,166**	1,267	**3,607**	3,866
Transportation and blending	**22**	18	**62**	55	**–**	–	**–**	–	**(17)**	(18)	**(57)**	(57)	**540**	747	**1,804**	2,473
Depletion, depreciation and amortization	**165**	137	**423**	402	**3**	2	**9**	7	**–**	–	**–**	–	**1,376**	1,226	**4,011**	3,474
Asset retirement obligation accretion	**8**	12	**23**	35	**–**	–	**–**	–	**–**	–	**–**	–	**44**	49	**130**	144
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(263)**	4	**(588)**	(14)
Gain on disposition of properties	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(49)**	–	**(49)**	–
Equity loss from investment	**–**	–	**–**	–	**20**	5	**32**	3	**–**	–	**–**	–	**20**	5	**32**	3
Total segmented expenses	**516**	565	**1,496**	1,706	**30**	15	**66**	37	**(19)**	(21)	**(64)**	(65)	**2,834**	3,298	**8,947**	9,946
Segmented earnings (loss) before the following	**190**	217	**538**	1,274	**3**	15	**37**	54	**(1)**	(4)	**3**	(3)	**280**	1,414	**623**	4,533
Non-segmented expenses																
Administration													**93**	87	**297**	267
Share-based compensation													**(87)**	(122)	**(102)**	210
Interest and other financing expense													**78**	79	**249**	239
Unrealized risk management activities													**(29)**	(150)	**200**	(47)
Foreign exchange loss													**323**	184	**596**	179
Total non-segmented expenses													**378**	78	**1,240**	848
Earnings (loss) before taxes													**(98)**	1,336	**(617)**	3,685
Current income tax (recovery) expense													**(5)**	89	**(113)**	400
Deferred income tax expense													**18**	208	**264**	554
Net earnings (loss)													**(111)**	1,039	**(768)**	2,731

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2015			Sep 30, 2014		
	Net expenditures	**Non-cash and fair value changes**[2]	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 63**	**$ (223)**	**$ (160)**	$ 1,028	$ (160)	$ 868
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**28**	**–**	**28**	65	–	65
	$ 91	**$ (223)**	**$ (132)**	$ 1,093	$ (160)	$ 933
Property, plant and equipment						
Exploration and Production						
North America [3]	**$ 989**	**$ (111)**	**$ 878**	$ 5,443	$ 302	$ 5,745
North Sea	**196**	**(3)**	**193**	295	–	295
Offshore Africa	**399**	**–**	**399**	89	–	89
	1,584	**(114)**	**1,470**	5,827	302	6,129
Oil Sands Mining and Upgrading [4]	**2,024**	**(86)**	**1,938**	2,248	(92)	2,156
Midstream	**6**	**–**	**6**	78	–	78
Head office	**24**	**–**	**24**	33	(1)	32
	$ 3,638	**$ (200)**	**$ 3,438**	$ 8,186	$ 209	$ 8,395

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) The above noted figures do not include the impact of a pre-tax gain on the sale of properties totaling $49 million.

(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	Total Assets	
	Sep 30 2015	Dec 31 2014
Exploration and Production		
North America	**$ 32,418**	$ 34,382
North Sea	**2,914**	2,711
Offshore Africa	**1,757**	1,214
Other	**70**	18
Oil Sands Mining and Upgrading	**22,249**	20,702
Midstream	**1,090**	1,048
Head office	**130**	125
	$ 60,628	$ 60,200

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 2015. 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, 2015:

Interest coverage (times)	
Net earnings [1]	2.5x
Cash flow from operations [2]	12.7x

(1) Net earnings plus income taxes and interest expense excluding current and deferred PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

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

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, November 5, 2015. The North American conference call number is 1-877-223-4471 and the outside North American conference call number is 001-647-788-4922. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, November 19, 2015. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference ID number to use is 11940896.

WEBCAST

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

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