FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2017 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2017 FOURTH QUARTER AND YEAR END RESULTS

Commenting on the Company's results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "In 2017, Canadian Natural continued to execute on its defined strategy and completed its transition to a long life low decline asset base with the completion and ramp-up of the Horizon Phase 3 expansion. The Company's focus on balanced capital allocation was evident in 2017 as economic resource development, increased balance sheet strength, execution on transformational acquisitions and free cash flow generation combined with our ability to execute with excellence, drove a strong year for the Company."

Canadian Natural's President, Tim McKay, added, "Strong production of Synthetic Crude Oil ("SCO") is targeted from our Oil Sands Mining and Upgrading operations with the midpoint of guidance at 450,000 bbl/d of SCO in the first quarter of 2018. With the completion of Phase 3 at Horizon, production has been strong averaging over 247,000 bbl/d of SCO since December 1, 2017 and operations at our Athabasca Oil Sands Project ("AOSP") continue to perform as expected with integration continuing during the Company's nine months of mine operations. The Company's Oil Sands Mining and Upgrading segment, conventional light oil in Canada and our international assets now make up over 50% of our corporate liquids production mix, a significant increase from approximately 32% in 2016. These products provide significant value to the Company as they are priced in close relation to the high value West Texas Intermediate ("WTI") crude oil commodity price.

Our focus on effective and efficient operations resulted in strong operating costs in 2017. Operating costs were within or on the lower end of corporate guidance ranges. Specifically, Horizon operating costs averaged $21.46/bbl of SCO in 2017, after adjusting for planned downtime, excellent results, with the Company looking to capture additional saving opportunities in 2018.

In 2017, Canadian Natural continued its strong track record of delivering excellent finding and development and acquisition costs and reserve replacement ratios, reflecting the strength of our assets and our ability to execute effectively and efficiently. Our reserve additions in the year were strong with gross proved crude oil, SCO, bitumen and NGL reserves increasing 59% to 7.74 billion barrels and proved natural gas reserves increasing 2% to 6.77 trillion cubic feet. Total proved plus probable BOE reserve life index of the Company is now 33.0 years, with low finding, development and acquisition costs of $12.29/BOE for proved reserves, including the change in future development capital. Additionally, our execution delivered strong reserve replacement ratios of 887% on proved developed producing reserves and 927% on total proved reserves, driven by our low sustaining capital requirement, resulting in significant free cash flow that provides sustainability through any commodity price cycle."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "The financial strength of the Company was displayed in 2017 as we were able to opportunistically acquire accretive assets and bring the Horizon project to completion, making the Company much more robust and sustainable. As a result, annual funds flow and net earnings were significant at approximately $7.3 billion and $2.4 billion respectively, all achieved with an annual average WTI crude oil price under US$51.00/bbl. The resulting free cash flow allowed the Company to increase liquidity to $4.25 billion and reduce debt to annual adjusted EBITDA to 2.7x at year end.

In Q4/17 funds flow reached approximately $2.3 billion, resulting in a Q4/17 ending debt reduction of approximately $460 million, when compared to Q3/17 levels, supporting our near term focus to strengthen our balance sheet. Additionally, as of the April 1, 2018 dividend payment, the Company's Board of Directors has increased our quarterly dividend by 22% to $0.335 per share, reflecting the strength and robustness of our assets and our ability to generate free cash flow. The increase marks the 18th consecutive year of dividend increases, and confirms our commitment to sustainable and increasing returns to shareholders."

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2017**	 Sept 30 2017	 Dec 31 2016	Year Ended **Dec 31 2017**	 Dec 31 2016
Net earnings (loss)	**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Per common share – basic	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.04**	$ (0.19)
– diluted	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.03**	$ (0.19)
Adjusted net earnings (loss) from operations (1)	**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)
Per common share – basic	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
– diluted	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
Funds flow from operations (2)	**$ 2,307**	$ 1,675	$ 1,677	**$ 7,347**	$ 4,293
Per common share – basic	**$ 1.89**	$ 1.38	$ 1.52	**$ 6.25**	$ 3.90
– diluted	**$ 1.88**	$ 1.37	$ 1.50	**$ 6.21**	$ 3.89
Capital expenditures, excluding AOSP acquisition costs (3)	**$ 1,143**	$ 2,094	$ 411	**$ 4,972**	$ 3,794
Total net capital expenditures (3)	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794
Daily production, before royalties					
Natural gas (MMcf/d)	**1,656**	1,664	1,646	**1,662**	1,691
Crude oil and NGLs (bbl/d)	**744,100**	759,189	585,185	**685,236**	523,873
Equivalent production (BOE/d) (4)	**1,020,094**	1,036,499	859,577	**962,264**	805,782

(1) Adjusted net earnings (loss) 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) Funds flow from operations (formally 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) For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

(4) 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.

Annual Highlights

- Net earnings of $2,397 million were realized in 2017, resulting in adjusted net earnings of $1,403 million, representing an increase of $2,072 million in adjusted net earnings compared to 2016 levels.
- Funds flow generation increased significantly in 2017 with annual funds flow from operations of $7,347 million, an increase of 71% or $3,054 million compared to 2016 levels of $4,293 million.
- Record annual production volumes of 962,264 BOE/d were achieved in 2017, representing an increase of 19% from 2016 levels. The increase was a result of the Company's liquids segment, with annual crude oil and NGL production volumes reaching 685,236 bbl/d, an increase of 31% from 2016 levels.
- Canadian Natural's balance of products has improved significantly with current production mix on a BOE/d basis of 50% light crude oil blends, 25% heavy crude oil blends and 25% natural gas, based upon the mid-point of annual 2018 production guidance, a significant change from 2016 when our production mix was approximately 32% light crude oil blends, 33% heavy crude oil blends and 35% natural gas.
- In 2017, the Company achieved annual natural gas production volumes of 1,662 MMcf/d, consistent with 2016 levels. Natural gas volumes were maintained as the Company made strategic, return based capital allocation decisions to maintain the Company's natural gas business.

- Canadian Natural is committed to reducing its environmental footprint by leveraging technology, adopting innovation and maintaining effective and efficient operations. The Company has made significant gains in our environmental performance:
  - Canadian Natural's greenhouse gas ("GHG") emissions intensity decreased 16% from 2012 to 2016. Additionally methane emissions from our Alberta heavy crude oil operations decreased 71% over the same period.
  - The Company has developed a pathway utilizing technology advancements to reduce its oil sands GHG emissions intensity to be equivalent with light crude oil in North America.
  - Over 1.5 million tonnes of annual CO2 capture and sequestration capacity at the Company's Oil Sands Mining and Upgrading operations.
  - When the North West Redwater Refinery is fully on-stream, Canadian Natural targets to capture and sequester 2.7 million tonnes of CO2 annually, the 4th largest of all industries globally.
  - The Company has a strong commitment to effective and efficient water management with over 90% of water used in our Oil Sands Mining and Upgrading operations being recycled water.
  - Canadian Natural has invested over $500 million in Research and Development in each of the last two years. In 2016 Canadian Natural was the 4th largest Research and Development investor of all industries in Canada.
- Environmental and safety performance are key metrics in our compensation program, along with key operational metrics and financial metrics such as total shareholder return, return on capital, return on equity and debt metrics such as debt to EBITDA and debt to book capitalization.
- At the Company's world class Oil Sands Mining and Upgrading assets, the Athabasca Oil Sands Project ("AOSP") and Horizon Oil Sands ("Horizon"), operations were strong in 2017, with annual and Q4/17 production reaching 282,026 bbl/d and 321,496 bbl/d respectively, of Synthetic Crude Oil ("SCO").
  - During 2017, at Horizon, the Company successfully completed the Phase 3 expansion, the final component of the Company's transition to a long life low decline asset base. The completion of the Horizon Phase 3 expansion has increased the output of fully upgraded 34 degree API light sweet SCO, with December production averaging 247,226 bbl/d of SCO. The resulting impact to operating costs was significant, with December operating costs below $20.00/bbl of SCO.
    - Horizon achieved record annual production of 170,089 bbl/d of SCO in 2017, a 38% increase over 2016 levels, as a result of a full year of Phase 2B production and the completion and tie-in of the Horizon Phase 3 expansion.
    - Operational performance has been strong after the ramp-up of the Horizon Phase 3 expansion as production averaged over 247,000 bbl/d of SCO since December 1, 2017.
    - Through safe, steady and reliable operations and a strong focus on continuous improvement, after adjusting for planned downtime in 2017, the Company realized record low annual average operating costs of $21.46/bbl of SCO at Horizon, a 15% reduction from 2016 levels. Including turnaround time, operating costs were $24.98/bbl of SCO, a 13% reduction from 2016 levels.
    - In 2017, Horizon project capital expenditures totaled $821 million, $89 million below the Company's 2017 corporate guidance.
  - At the AOSP, the Company operated the Albian mines for 7 months in 2017 and achieved strong reliability and utilization. As a result, the Company added 111,937 bbl/d and 180,221 bbl/d of AOSP SCO in 2017 and Q4/17 respectively, net to Canadian Natural, both above the midpoint of previously issued guidance. A combination of strong production and modest integration gains resulted in operating costs of $26.34/bbl for upgraded products, below the Company's 2017 operating cost guidance of $27.00/bbl to $31.00/bbl.
- The transition to a long life low decline asset base is complete following the Horizon Phase 3 expansion. Canadian Natural’s production is resilient as long life low decline assets make up approximately 73% of 2018 liquids production guidance, including AOSP, Horizon, Pelican Lake and Thermal in situ oil sands assets.
- The Company’s 2017 drilling program consisted of 523 net wells, excluding strat/service wells, a 333 net well increase over its 2016 drilling program. The Company continues to be prudent with its capital allocation in a volatile commodity price environment, maintaining significant capital flexibility in its 2018 budget that is targeting 608 net producing wells over the year.

- Thermal in situ oil sands ("thermal in situ") annual production volumes reached 120,140 bbl/d, at the top end of 2017 guidance, representing an 8% increase from 2016 levels.
  - At Primrose, production was strong in 2017 with volumes reaching 81,501 bbl/d, an increase of 11% from 2016 levels. Operating costs in 2017 were $12.33/bbl, including energy costs, slightly below 2016 costs.
  - At Kirby South the Company's Steam Assisted Gravity Drainage ("SAGD") project, annual production volumes of 36,107 bbl/d were achieved, a 4% decrease from 2016 levels, as the Company successfully completed planned turnaround activities in the year.
    - Including energy costs, Kirby South achieved annual operating costs of $9.50/bbl, in-line with 2016 levels.
- Pelican Lake operations were strong with annual production of 51,743 bbl/d, an increase of 9% from 2016 levels. The increase was a result of the Company's successful integration of the acquired assets in Q4/17 and a modest drilling program. The acquired assets are now fully integrated and the Company has begun to re-initiate polymer flood conversions across portions of the acquired lands. The conversions will continue throughout 2018 adding to Canadian Natural's long life low decline asset mix.
  - Record low annual operating costs of $6.42/bbl were achieved in 2017, a 3% reduction from 2016 levels.
- Primary heavy crude oil production decreased as expected to 95,530 bbl/d in 2017, following the Company's proactive decision to reduce its primary heavy crude oil drilling program from peak levels in 2014. Canadian Natural is an industry leading primary heavy crude oil producer and continues to focus on optimization of its assets.
  - Operating costs of $15.71/bbl were realized in 2017 in primary heavy crude oil.
- North America light crude oil and NGL production increased 5% to 92,036 bbl/d in 2017 from 2016 levels, due to a modest drilling program and minor property acquisitions. As a result, the Company's conventional light crude oil and NGL production was approximately equivalent to the Company's primary heavy crude oil production.
  - Operating costs of $14.30/bbl were realized in 2017 in North America light crude oil and NGL.
- North America natural gas production was 1,601 MMcf/d in 2017, in-line with 2016 levels, after continued impacts of poor reliability at a third party facility and the strategic decision to maintain natural gas production.
  - Operating costs in North America natural gas were within guidance at $1.19/Mcf in 2017.
- International Exploration & Production ("E&P") annual production volumes were within production guidance and averaged 43,761 bbl/d.
  - North Sea volumes of 23,426 bbl/d were realized in 2017, consistent with 2016 levels, due to a modest drilling program in the year partially offsetting declines. Additionally, the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in annual operating costs decreasing by 14% to $36.60/bbl, from 2016 levels.
  - Offshore Africa's production decreased by 22%, as expected to 20,335 bbl/d from 2016 levels, due to normal declines and planned turnarounds in 2017. Operating costs in Côte d'Ivoire were strong in 2017 at $12.41/bbl, within corporate guidance.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2017, the Company had $4.25 billion of available liquidity, including cash and cash equivalents, an increase of $1.21 billion from December 31, 2016. Year end 2017 debt to book capitalization was 41% and debt to adjusted EBITDA strengthened to 2.7x.
- The Company remained focused on returns to shareholders in 2017 increasing dividends by approximately 17% to $1.10 per share. Subsequent to year end the Company increased its quarterly dividend by 22% to $0.335 per share payable on April 1, 2018. The increase marks the 18th consecutive year that Canadian Natural has increased its dividend, reflecting the Board of Director's confidence in the Company's sustainability and robustness of the asset base driving its ability to generate significant funds flow.
- Effective March 1, 2018, the Company promoted Tim McKay to President and Mr. McKay has been appointed to the Company's Board of Directors. Additionally, Steve Laut has assumed the role of Executive Vice-Chairman. The Company takes a very proactive and disciplined approach to succession, with well-planned and very successful transitions, ensuring we maintain our strong corporate culture and top tier performance.

2017 Reserves Update

- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs as at December 31, 2017 (all reserve values are Company Gross unless stated otherwise).
  - Proved crude oil, SCO, bitumen and NGL reserves increased 59% to 7.74 billion barrels. Proved natural gas reserves increased 2% to 6.77 Tcf. Total proved reserves increased 49% to 8.87 billion BOE. The increase is largely driven by the Company's acquisition of AOSP.
  - Proved developed producing reserve additions and revisions are 3.024 billion barrels of crude oil, SCO, bitumen and NGL and 536 billion cubic feet of natural gas. The total proved developed producing reserves replacement ratio is 887%.
  - Proved reserve additions and revisions are 3.126 billion barrels of crude oil, SCO, bitumen and NGL and 761 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 927%. The total proved BOE reserve life index is 24.6 years.
  - Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 34% to 10.26 billion barrels. Proved plus probable natural gas reserves increased 6% to 9.62 Tcf. Total proved plus probable reserves increased 29% to 11.87 billion BOE.
  - Proved plus probable reserve additions and revisions are 2.846 billion barrels of crude oil, bitumen, SCO and NGL and 1.15 trillion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio is 866%. The total proved plus probable BOE reserve life index is 33.0 years.
  - Proved finding, development and acquisition (FD&A) cost, excluding changes in future development capital (FDC), is strong at $5.15/BOE. Proved plus probable FD&A is $5.52/BOE.
  - Proved net present value of future net revenues, before income tax, discounted at 10%, is $89.8 billion, a 30% increase from the year end 2016 evaluation. Proved plus probable net present value is $114.5 billion, a 24% increase from year end 2016.

Fourth Quarter Highlights

- Net earnings of $396 million and adjusted net earnings of $565 million were realized in Q4/17. Canadian Natural generated significant funds flow from operations of $2,307 million in Q4/17, increases of $632 million and $630 million over Q3/17 and Q4/16 levels, respectively.
- The Company's corporate production volumes averaged a record 1,020,094 BOE/d in Q4/17, in-line with Q3/17 levels and a 19% increase from Q4/16 levels.
- Canadian Natural's corporate crude oil and NGL production volumes averaged 744,100 bbl/d, a decrease of 2% from Q3/17 due to Horizon planned downtime for turnaround and tie-in activities. Crude oil and NGL production volumes increased from Q4/16 by 27% primarily as a result of high reliability and strong production from the Horizon Phase 2B and Phase 3 expansions and a full quarter of production from the AOSP.
- At the Company's world class Oil Sands Mining and Upgrading assets, the AOSP and Horizon, operations were strong in Q4/17 with quarterly production reaching 321,496 bbl/d of SCO.
  - At Horizon, the Phase 3 expansion was completed in Q4/17, marking the completion of the Company's transition to a long life low decline asset base.
    - Q4/17 production of 141,275 bbl/d of SCO was realized as the Company completed turnaround and tie-in activities for the Horizon Phase 3 expansion. As a result of the majority of the planned downtime coming in Q4/17, production in the quarter decreased from Q3/17 levels by 10%. The ramp-up of the Phase 3 expansion performed better than originally targeted, with December 2017 production averaging approximately 247,226 bbl/d of SCO, approximately 7,200 bbl/d of SCO greater than originally targeted.
    - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized average unadjusted operating costs of $32.29/bbl in Q4/17, a strong result given 33 days of planned downtime in the quarter as part of the 52 day turnaround and tie-in related to the Phase 3 expansion. After normalizing for planned downtime, quarterly operating costs were strong at $21.13/bbl of SCO in Q4/17.

- At the AOSP in Q4/17, the Company's second full quarter of operations, production was 180,221 bbl/d of AOSP SCO, net to Canadian Natural, strong results given planned pitstops at the Jackpine and Muskeg River mines in the quarter. Including the impact of planned pit stops, operating costs of $27.95/bbl were achieved, an increase of 14% from Q3/17 levels.

▪ Thermal in situ operations were strong in Q4/17, with production averaging 124,121 bbl/d, in-line with Q3/17 and a 4% decrease from Q4/16 levels.

  - Primrose production was strong in Q4/17 averaging 84,834 bbl/d, an increase of 5% from Q3/17. Including energy costs, operating costs of $11.16/bbl were achieved in the quarter.
  - Kirby South, the Company's SAGD project achieved production of 35,320 bbl/d in Q4/17.
    - Including energy costs, strong operating costs of $9.74/bbl were achieved in the quarter. Kirby South's Steam to Oil Ratio ("SOR") was 2.9 in Q4/17, as the Company began steam circulation of new well pairs drilled in Q4/17. Normalized to exclude wells in circulation, the SOR was 2.7 in Q4/17.

- Pelican Lake heavy crude oil production of 65,654 bbl/d in Q4/17 increased by 38% from both Q3/17 and Q4/16 levels, as a result of a full quarter of production of the fully integrated, recently acquired assets. Operations continued to be optimized in the quarter, resulting in favorable operating costs of $6.81/bbl in Q4/17, increases of 14% and 4% from Q3/17 and Q4/16 levels respectively, due to the integration of acquired assets.

▪ Primary heavy crude oil production averaged 99,326 bbl/d in Q4/17, in-line with Q3/17, as a result of the Company's successful drilling program.

▪ North America light crude oil and NGL quarterly production averaged 94,437 bbl/d, representing 2% and 8% increases from Q3/17 and Q4/16 levels respectively, as a result of a successful drilling program.

▪ The Company's North America natural gas production in Q4/17 averaged 1,596 MMcf/d, in-line with Q3/17 and Q4/16 levels.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between 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. This balance provides optionality for capital investments, facilitating improved value for the Company's shareholders.

Underpinning this asset base is long life low decline production from Horizon mining and upgrading and the AOSP mining and upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement costs, and effective and efficient operations means these assets provide substantial and sustainable cash flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its conventional asset base. These projects can be executed quickly and with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs which can be optimized over time. Additionally, by owning and operating most of the related infrastructure, Canadian Natural is able to control a major component of its operating cost and minimize production commitments. Low capital exposure projects can be quickly stopped or started depending upon success, market conditions, or corporate needs.

Canadian Natural's balanced portfolio, built with both long life low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

	Year Ended Dec 31			
	2017		2016	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**529**	**495**	188	174
Natural gas	**27**	**21**	11	9
Dry	**7**	**7**	7	7
Subtotal	**563**	**523**	206	190
Stratigraphic test / service wells	**289**	**289**	268	268
Total	**852**	**812**	474	458
Success rate (excluding stratigraphic test / service wells)		**99%**		96%

- The Company's total crude oil and natural gas drilling program was 523 net wells for the year ended December 31, 2017, excluding strat/service wells, an increase of 333 net wells from the same period in 2016. The change in drilling reflects the flexibility of Canadian Natural's resource development program and the Company's disciplined capital allocation process.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs production (bbl/d)	**259,416**	238,844	232,019	**239,309**	239,912
Net wells targeting crude oil	**123**	145	75	**472**	170
Net successful wells drilled	**120**	144	72	**466**	163
Success rate	**98%**	99%	96%	**99%**	96%

- Annual production volumes of North America crude oil and NGLs averaged 239,309 bbl/d in 2017, in-line with 2016 levels and within the Company's annual production guidance.
- Pelican Lake operations were strong with annual production of 51,743 bbl/d, an increase of 9% from 2016 levels. The increase was as a result of the Company's successful integration of the acquired assets in Q4/17 and a modest drilling program. The acquired assets are now fully integrated and the Company has begun to re-initiate polymer flood conversions across portions of the acquired lands. The conversions will continue throughout 2018 adding to Canadian Natural's long life low decline asset mix.
  - Record low annual operating costs of $6.42/bbl were achieved in 2017, a 3% reduction from 2016 levels.
  - Overall 56% of the Pelican Lake pool is under polymer flood on an area basis. Canadian Natural is targeting to ultimately convert approximately 70% of the pool to polymer flood.
- Primary heavy crude oil production decreased as expected to 95,530 bbl/d in 2017, following the Company's proactive decision to reduce its primary heavy crude oil drilling program from peak levels in 2014. Canadian Natural is the industry leading primary heavy crude oil producer and continues to focus on optimization of the assets.
  - Operating costs of $15.71/bbl were realized in 2017.
  - Drilling continued in primary heavy crude oil in 2017 with 415 net wells drilled, an increase of 255 wells from 2016 levels.
- North America light crude oil and NGL production increased 5% to 92,036 bbl/d in 2017 from 2016 levels, due to a modest drilling program and minor property acquisitions. As a result, our conventional light crude oil and NGL production was approximately equivalent to the Company's primary heavy crude oil production.
  - Operating costs of $14.30/bbl were realized in 2017.
- The Company’s 2018 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 253,000 bbl/d - 263,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Bitumen production (bbl/d)	**124,121**	122,372	129,329	**120,140**	111,046
Net wells targeting bitumen	**5**	10	8	**27**	9
Net successful wells drilled	**5**	10	8	**27**	9
Success rate	**100%**	100%	100%	**100%**	100%

- Thermal in situ annual production volumes reached 120,140 bbl/d, at the top end of 2017 guidance, representing an 8% increase from 2016 levels.
  - At Primrose, production was strong in 2017 with volumes reaching 81,501 bbl/d, an increase of 11% from 2016 levels. Operating costs were maintained in the year at $12.33/bbl, including energy costs, slightly below 2016 costs.
    - Additionally, strong results from the Company's low pressure steamflood continue at Primrose. The 2017 annual production under steamflood averaged 39,300 bbl/d, an increase from 2016 average levels of approximately 10,900 bbl/d.
  - At Kirby South, the Company's SAGD project, the Company achieved annual production volumes of 36,107 bbl/d, a 4% decrease from 2016 levels, as a result of planned turnaround activities in the year.
    - Including energy costs, Kirby South achieved annual operating costs of $9.50/bbl, in-line with 2016 levels. Annual SOR at Kirby South was 2.8 in 2017.
  - Kirby North, the Company's targeted 40,000 bbl/d SAGD project with targeted first oil in Q1/20 continues to be trending slightly ahead of schedule and cost performance is trending on budget. Civil works and tank contracts at the plant site have been completed with building and equipment modules set at the plant site. The construction and drilling workforce is currently at 740 people, including satellite module yards.

- The Company's 2018 thermal in situ annual production guidance remains unchanged and is targeted to range between 107,000 bbl/d - 127,000 bbl/d.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Natural gas production (MMcf/d)	**1,596**	1,593	1,578	**1,601**	1,622
Net wells targeting natural gas	**2**	3	4	**22**	9
Net successful wells drilled	**2**	3	4	**21**	9
Success rate	**100%**	100%	100%	**95%**	100%

- North America natural gas production was 1,601 MMcf/d in 2017, in-line with 2016 levels, after continued impacts of poor reliability at a third party facility and the strategic decision to maintain natural gas production.
  - Operating costs in North America natural gas were within guidance at $1.19/Mcf in 2017.
  - Production in Q4/17 was below corporate guidance primarily due to a proactive decision to shut-in production volumes of approximately 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at a third party facility.
  - The Company uses approximately 32% of its total equivalent gas production internally in its operations providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 29% of the natural gas production is exported to other North American markets or sold internationally, with the remaining 39% of the Company's production being exposed to AECO/Station 2 pricing.
- The Company's 2018 total natural gas annual production guidance remains unchanged and is targeted to range from 1,650 MMcf/d - 1,710 MMcf/d.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil production (bbl/d)					
North Sea	**19,548**	24,832	24,085	**23,426**	23,554
Offshore Africa	**19,519**	18,776	21,689	**20,335**	26,096
Natural gas production (MMcf/d)					
North Sea	**37**	46	44	**39**	38
Offshore Africa	**23**	25	24	**22**	31
Net wells targeting crude oil	**—**	—	0.9	**1.8**	2.1
Net successful wells drilled	**—**	—	0.9	**1.8**	2.1
Success rate	**—**	—	100%	**100%**	100%

- International E&P annual production volumes were within production guidance and reached 43,761 bbl/d.
  - North Sea volumes of 23,426 bbl/d were realized in 2017, consistent with 2016 levels, due to a modest drilling program in the year helping to offset declines. Additionally, the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in annual operating costs decreasing by 14% to $36.60/bbl, from 2016 levels.
    - In 2018, the Company is targeting to drill 4.6 net producing wells and 0.9 net injector wells in the North Sea, scheduled to commence in Q1/18. The program targets to add average net production of approximately 3,000 bbl/d in Q4/18.
  - Offshore Africa's production decreased by 22%, as expected to 20,335 bbl/d from 2016 levels, after a successful infill drilling program in early 2016 and no drilling in 2017. Operating costs in Côte d'Ivoire were strong in 2017 at $12.41/bbl, within corporate guidance.
    - In 2018, the Company is targeting to drill 1.7 net producing wells and 1.2 net injector wells at Baobab which are scheduled to commence in Q2/18. The program targets to add average net production of approximately 5,700 bbl/d in Q4/18.
- The Company's 2018 International annual production guidance remains unchanged and is targeted to range from 40,000 bbl/d - 45,000 bbl/d.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Synthetic crude oil production (bbl/d) (1)	**141,275**	156,465	178,063	**170,089**	123,265

(1) Q4/17 SCO production before royalties excludes 1,730 bbl/d of SCO consumed internally as diesel (Q3/17 – 0 bbl/d; Q4/16 – 1,619 bbl/d; year ended December 31, 2017 – 651 bbl/d; year ended December 31, 2016 – 1,966 bbl/d).

- During 2017 at Horizon, the Company successfully completed the Phase 3 expansion, the final component of the Company's transition to a long life low decline asset base. The completion of the Horizon Phase 3 expansion has increased the output of fully upgraded 34 degree API light sweet SCO, with December production averaging 247,226 bbl/d of SCO. The resulting impact to operating costs was significant, with December operating costs below $20.00/bbl of SCO.
  - Horizon achieved record annual production of 170,089 bbl/d of SCO in 2017, a 38% increase over 2016 levels, as a result of a full year of Phase 2B production and the completion and tie-in of the Horizon Phase 3 expansion.
  - Operational performance has been strong after the ramp-up of the Horizon Phase 3 expansion as production has averaged over 247,000 bbl/d of SCO since December 1, 2017.
  - Through safe, steady and reliable operations and a strong focus on continuous improvement, after adjusting for planned downtime in 2017, the Company realized record low annual average operating costs of $21.46/bbl of SCO at Horizon, a 15% reduction from 2016 levels. Including planned downtime, operating costs were $24.98/bbl of SCO, a 13% reduction from 2016 levels.
  - In 2017, Horizon project capital expenditures totaled $821 million, $89 million below the Company's 2017 corporate guidance.
  - The engineering and design work is proceeding as planned on the potential Paraffinic and VGO expansions at Horizon and will continue throughout 2018.
  - Ongoing work is proceeding to define if incremental capacity is attainable at Horizon and is targeted to be identified in Q2/18.
- Directive 85 (formerly Directive 74) implementation at Horizon remains on track and was 74% physically complete as at December 31, 2017. This project includes research into tailings management and investments in technological advancements for the cessation of the use of traditional tailings ponds.

North America Oil Sands Mining and Upgrading – AOSP

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Synthetic crude oil production (bbl/d) (1)	**180,221**	197,900	—	**111,937**	—

(1) Consists of heavy and light synthetic crude oil products.

- At the AOSP, the Company operated the Albian mines for 7 months in 2017 and strong reliability and utilization were achieved. As a result the Company added 111,937 bbl/d of AOSP SCO, net to Canadian Natural in 2017, above the midpoint of previously issued guidance. A combination of strong production and modest integration gains resulted in operating costs of $26.34/bbl for upgraded products, below the Company's 2017 operating cost guidance of $27.00/bbl to $31.00/bbl.
  - In early Q4/17, Canadian Natural successfully completed planned pit stops at both the Jackpine and Muskeg River mines.
  - The Company will continue to operate in the most effective and efficient manner and will continue to be diligent in order to identify additional synergies.
- The Company's 2018 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range from 415,000 bbl/d - 450,000 bbl/d of upgraded products.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2017	Sept 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 55.39**	$ 48.19	$ 49.33	**$ 50.93**	$ 43.37
WCS blend differential from WTI (%) (2)	**22%**	21%	30%	**23%**	32%
SCO price (US$/bbl)	**$ 58.64**	$ 48.83	$ 48.91	**$ 52.20**	$ 43.94
Condensate benchmark pricing (US$/bbl)	**$ 57.96**	$ 47.96	$ 48.37	**$ 51.65**	$ 42.51
Average realized pricing before risk management (C$/bbl) (3)	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.85**	$ 1.94	$ 2.67	**$ 2.30**	$ 1.98
Average realized pricing before risk management (C$/Mcf)	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32

(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.

- WTI averaged US$50.93/bbl in 2017, an increase of 17% from US$43.37/bbl in 2016. WTI averaged US$55.39/bbl for Q4/17, an increase of 12% from US$49.33/bbl in Q4/16, and an increase of 15% from US$48.19/bbl for Q3/17. WTI pricing for Q4/17 and annual 2017 has increased from the comparable periods due to declines in global crude oil inventories as a result of OPEC’s adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil. Going forward, the Company expects WTI pricing to continue to reflect volatility in supply and demand factors and geopolitical events.
- The WCS Heavy Differential averaged US$11.97/bbl in 2017 from US$13.91/bbl in 2016, representing a 14% decrease. The WCS Heavy Differential averaged US$12.28/bbl for Q4/17 , a decrease of 16% from US$14.59/bbl for Q4/16 , and an increase of 24% from US$9.94/bbl for Q3/17. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. Subsequent to quarter end, the WCS Heavy Differential widened due to third party pipeline outages and timing of access to rail for industry to move the incremental barrels.

- Canadian Natural contributed approximately 190,000 bbl/d of its heavy crude oil stream to the WCS blend in Q4/17. The Company remains the largest contributor to the WCS blend, accounting for 48% of the total blend.
- The SCO price averaged US$52.20/bbl in 2017, an increase of 19% from US$43.94/bbl in 2016. The SCO price averaged US$58.64/bbl for Q4/17, an increase of 20% from US$48.91/bbl in Q4/16, and an increase of 20% from US$48.83/bbl for Q3/17. The increase in SCO pricing for Q4/17 and 2017 from the comparable periods was primarily due to changes in WTI benchmark.
- AECO natural gas prices averaged $2.30/GJ in 2017 from $1.98/GJ in 2016, representing an increase of 16%. AECO natural gas prices averaged $1.85/GJ for Q4/17, a decrease of 31% from $2.67/GJ in Q4/16, and a decrease of 5% from $1.94/GJ in Q3/17. The increase in natural gas prices in 2017 compared with 2016 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels. The decrease in AECO natural gas prices in Q4/17 compared with Q4/16 and Q3/17 continued to reflect third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.
- 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 and create demand for 79,000 bbl/d of dilbit that will not require export pipelines, 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: https://nwrsturgeonrefinery.com/whats-happening/news/.
  - The North West Redwater refinery began processing light crude oil late in November 2017, and continues to progress with its planned ramp-up schedule.

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 funds flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs 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 levels of 1,020,094 BOE/d in Q4/17, with approximately 98% of total production located in G7 countries.
  - Canadian Natural's balance of products has improved significantly with current product mix on a BOE/d basis of 50% light crude oil blends, 25% heavy crude oil blends and 25% natural gas, based upon the mid-point of annual 2018 production guidance, a significant change from 2016 when our product mix was approximately 32% light crude oil blends, 33% heavy crude oil blends and 35% natural gas.
  - The transition to a long life low decline asset base is complete following the Horizon Phase 3 expansion. Canadian Natural's production is resilient as long life low decline assets makes up approximately 73% of 2018 liquids production guidance, when including the AOSP, Horizon, Pelican Lake and Thermal in situ oil sands assets.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2017, the Company had $4.25 billion of available liquidity, including cash and cash equivalents, an increase of $1.21 billion from December 31, 2016.
  - Important metrics improved in Q4/17, with debt to book capitalization at 41% and debt to adjusted EBITDA strengthening to 2.7x, as at December 31, 2017.
- Balance sheet strength continues to be a focus of the Company and strong financial performance in the quarter resulted in a Q4/17 ending debt reducing approximately $460 million from Q3/17 levels, while liquidity increased by approximately $300 million, over the same period.
  - Subsequent to December 31, 2017, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes from funds flow from operations.
  - As at December 31, 2017, the Company's $3,000 million non-revolving term loan facility which it entered into during Q2/17 to finance the acquisition of AOSP and other assets was fully drawn. Subsequent to December 31, 2017, the Company repaid and canceled $150 million of the outstanding facility from funds flow from operations, leaving $2,850 million outstanding.
  - Subsequent to December 31, 2017, the Company fully repaid and canceled the $125 million non-revolving credit facility from funds flow from operations.

    - Subsequent to December 31, 2017, the Company extended the $750 million non-revolving credit facility originally due February 2019 to February 2021.

- In addition to its strong funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at December 31, 2017, these financial levers include the Company's third party equity investments of approximately $893 million.
- The Company remained focused on returns to shareholders in 2017 increasing dividends by approximately 17% to $1.10 per share. Subsequent to year end the Company increased its quarterly dividend by 22% to $0.335 per share payable on April 1, 2018. The increase marks the 18th consecutive year that Canadian Natural has increased its dividend, reflecting the Board of Director's confidence in the Company's sustainability and robustness of the asset base driving the ability to generate significant funds flow.

OUTLOOK

The Company forecasts annual 2018 production levels to average between 815,000 and 885,000 bbl/d of crude oil and NGLs and between 1,650 and 1,710 MMcf/d of natural gas, before royalties. Q1/18 production guidance before royalties is forecast to average between 821,000 and 869,000 bbl/d of crude oil and NGLs and between 1,600 and 1,650 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.

Canadian Natural's annual 2018 capital expenditures are targeted to be approximately $4.3 billion.

2017 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2017, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

Corporate Total

- Canadian Natural's 2017 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding the change in Future Development Capital ("FDC"), are $5.15/BOE for proved reserves and $5.52/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.29/BOE for proved reserves and $12.17/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 2017 production by 927%. Proved plus probable reserve additions and revisions replaced 2017 production by 866%.
- Proved reserves increased 49% to 8.871 billion BOE with reserve additions and revisions of 3.253 billion BOE. Proved plus probable reserves increased 29% to 11.866 billion BOE with reserve additions and revisions of 3.038 billion BOE.
- The proved BOE reserve life index is 24.6 years and the proved plus probable BOE reserve life index is 33.0 years.
- Recycle ratios are 4.5 times and 4.2 times for proved and proved plus probable reserves respectively, excluding the change in FDC. Including the change in FDC, recycle ratios are 1.9 times for both proved and proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 30% to $89.8 billion for proved reserves and increased 24% to $114.5 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 46% to $68.1 billion reflecting the completion of Horizon Phase 3 and the acquisition of AOSP.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $6.81/BOE for proved reserves and $5.57/BOE for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $11.31/BOE for proved reserves and $9.96/BOE for proved plus probable reserves.
- Proved reserve additions and revisions replaced 196% of 2017 production. Proved plus probable reserve additions and revisions replaced 240% of 2017 production.
- Proved reserves increased 7% to 3.397 billion BOE. This is comprised of 2.275 billion bbl of crude oil, bitumen, and NGL reserves and 6.730 Tcf of natural gas reserves.
- Proved plus probable reserves increased 6% to 5.482 billion BOE. This is comprised of 3.895 billion bbl of crude oil, bitumen, and NGL reserves and 9.520 Tcf of natural gas reserves.
- Proved reserve additions and revisions are 320 million bbl of crude oil, bitumen and NGL and 770 Bcf of natural gas. Proved plus probable reserve additions and revisions are 349 million bbl of crude oil, bitumen and NGL and 1,194 Bcf of natural gas.
- The proved BOE reserve life index is 16.2 years and the proved plus probable BOE reserve life index is 26.2 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Horizon and AOSP oil sands mining and upgrading delivered strong reserves results in 2017:
  - FD&A costs, excluding the change in FDC, are $4.78/bbl for proved reserves and $5.24/bbl for proved plus probable reserves.
  - FD&A costs, including the change in FDC, are $12.58/bbl for proved reserves and $12.78/bbl for proved plus probable reserves.
- Proved Synthetic Crude Oil ("SCO") reserves increased 106% to 5.264 billion bbl. Proved plus probable SCO reserves increased 68% to 6.063 billion bbl.
- SCO proved developed producing reserves increased 107% to 5.264 billion bbl reflecting the completion of Phase 3 at Horizon and the acquisition of AOSP.
- SCO reserves account for 59% of the Company's proved BOE reserves and 51% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves decreased 12% to 124 million BOE and proved plus probable reserves decreased 31% to 185 million BOE.
- Offshore Africa proved reserves decreased 7% to 86 million BOE and proved plus probable reserves decreased 7% to 136 million BOE.

2017 FD&A Costs excluding change in FDC

	Proved ($/BOE)	Proved Plus Probable ($/BOE)
North America E&P	$ 6.81	$ 5.57
Oil Sands Mining and Upgrading	$ 4.78	$ 5.24
Total Canadian Natural	$ 5.15	$ 5.52

2017 FD&A Costs including change in FDC

	Proved ($/BOE)	Proved Plus Probable ($/BOE)
North America E&P	$ 11.31	$ 9.96
Oil Sands Mining and Upgrading	$ 12.58	$ 12.78
Total Canadian Natural	$ 12.29	$ 12.17

Corporate Total

2017 Reserve Replacement

Reserves Category	% of 2017 Production Replaced
Proved developed producing	887%
Proved	927%
Proved plus probable	866%

Company Gross Reserves

Reserves Category	2016 (MMBOE)	2017 (MMBOE)	Increase
Proved developed producing	4,145	6,908	67%
Proved	5,969	8,871	49%
Proved plus probable	9,179	11,866	29%

2017 Recycle Ratios

Reserves Category	Excluding change in FDC
Proved	4.5 x
Proved plus probable	4.2 x

Reserves Category	Including change in FDC
Proved	1.9 x
Proved plus probable	1.9 x

Net Present Value of Future Net Revenues, before income tax, discounted at 10%

Reserves Category	2016 ($ billion)	2017 ($ billion)	Increase
Proved developed producing	46.7	68.1	46%
Proved	69.3	89.8	30%
Proved plus probable	92.3	114.5	24%

Summary of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	108	266	322	5,264	4,029	102	6,848
Developed Non-Producing	11	15	—	34	—	347	8	126
Undeveloped	46	75	61	994	—	2,354	119	1,687
Total Proved	171	198	327	1,350	5,264	6,730	229	8,661
Probable	68	74	142	1,230	799	2,790	106	2,884
Total Proved plus Probable	239	272	469	2,580	6,063	9,520	335	11,545
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	30					12		32
Developed Non-Producing	2					—		2
Undeveloped	51					8		52
Total Proved	83					20		86
Probable	42					47		50
Total Proved plus Probable	125					67		136
Total Company								
Proved								
Developed Producing	169	108	266	322	5,264	4,058	102	6,908
Developed Non-Producing	17	15	—	34	—	347	8	132
Undeveloped	188	75	61	994	—	2,366	119	1,831
Total Proved	374	198	327	1,350	5,264	6,771	229	8,871
Probable	170	74	142	1,230	799	2,848	106	2,995
Total Proved plus Probable	544	272	469	2,580	6,063	9,619	335	11,866

Summary of Company Net Reserves

As of December 31, 2017
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	103	91	207	262	4,552	3,654	80	5,904
Developed Non-Producing	10	13	—	28	—	312	6	109
Undeveloped	39	65	50	825	(9)	2,066	101	1,415
Total Proved	152	169	257	1,115	4,543	6,032	187	7,428
Probable	58	61	101	971	653	2,422	86	2,334
Total Proved plus Probable	210	230	358	2,086	5,196	8,454	273	9,762
North Sea								
Proved								
Developed Producing	25					17		28
Developed Non-Producing	4					—		4
Undeveloped	91					4		92
Total Proved	120					21		124
Probable	60					11		61
Total Proved plus Probable	180					32		185
Offshore Africa								
Proved								
Developed Producing	27					9		29
Developed Non-Producing	2					—		2
Undeveloped	41					6		42
Total Proved	70					15		73
Probable	32					32		37
Total Proved plus Probable	102					47		110
Total Company								
Proved								
Developed Producing	155	91	207	262	4,552	3,680	80	5,961
Developed Non-Producing	16	13	—	28	—	312	6	115
Undeveloped	171	65	50	825	(9)	2,076	101	1,549
Total Proved	342	169	257	1,115	4,543	6,068	187	7,625
Probable	150	61	101	971	653	2,465	86	2,432
Total Proved plus Probable	492	230	358	2,086	5,196	8,533	273	10,057

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	168	187	264	1,269	2,559	6,545	198	5,736
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	(25)	—	(4)
Technical Revisions	7	4	5	82	487	211	13	633
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	**171**	**198**	**327**	**1,350**	**5,264**	**6,730**	**229**	**8,661**

North Sea	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	134					41		141
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	4					(5)		3
Technical Revisions	(9)					(1)		(9)
Production	(9)					(14)		(11)
December 31, 2017	**120**					**21**		**124**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	87					31		92
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	3					(3)		2
Production	(7)					(8)		(8)
December 31, 2017	**83**					**20**		**86**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	389	187	264	1,269	2,559	6,617	198	5,969
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	14	—	20	—	276	15	99
Infill Drilling	4	7	—	—	—	191	17	60
Improved Recovery	—	1	1	—	—	1	—	2
Acquisitions	6	20	76	23	2,321	116	1	2,467
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	4	—	—	—	—	(30)	—	(1)
Technical Revisions	1	4	5	82	487	207	13	626
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	**374**	**198**	**327**	**1,350**	**5,264**	**6,771**	**229**	**8,871**

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	65	72	120	1,248	1,045	2,366	86	3,030
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	2	3	—	—	—	104	9	31
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(4)	—	1
Technical Revisions	(6)	(15)	(2)	(64)	(421)	18	1	(504)
Production	—	—	—	—	—	—	—	—
December 31, 2017	**68**	**74**	**142**	**1,230**	**799**	**2,790**	**106**	**2,884**

North Sea								
December 31, 2016	119					44		126
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(4)					5		(3)
Technical Revisions	(56)					(38)		(63)
Production	—					—		—
December 31, 2017	**60**					**11**		**61**

Offshore Africa								
December 31, 2016	46					49		54
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(4)					(2)		(4)
Production	—					—		—
December 31, 2017	**42**					**47**		**50**

Total Company								
December 31, 2016	230	72	120	1,248	1,045	2,459	86	3,210
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	8	—	19	—	278	10	88
Infill Drilling	3	3	—	—	—	104	9	32
Improved Recovery	—	—	1	—	—	—	—	1
Acquisitions	2	6	23	27	175	29	—	237
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	(3)	—	—	—	—	1	—	(2)
Technical Revisions	(66)	(15)	(2)	(64)	(421)	(22)	1	(571)
Production	—	—	—	—	—	—	—	—
December 31, 2017	**170**	**74**	**142**	**1,230**	**799**	**2,848**	**106**	**2,995**

Reconciliation of Company Gross Reserves

As of December 31, 2017
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	233	259	384	2,517	3,604	8,911	284	8,766
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	6	10	—	—	—	295	26	91
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	1	(11)	3	18	66	229	14	129
Production	(18)	(35)	(19)	(44)	(103)	(585)	(15)	(332)
December 31, 2017	**239**	**272**	**469**	**2,580**	**6,063**	**9,520**	**335**	**11,545**

North Sea	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	253					85		267
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	1					—		1
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(65)					(39)		(72)
Production	(9)					(14)		(11)
December 31, 2017	**180**					**32**		**185**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	133					80		146
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(1)					(5)		(2)
Production	(7)					(8)		(8)
December 31, 2017	**125**					**67**		**136**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2016	619	259	384	2,517	3,604	9,076	284	9,179
Discoveries	—	—	—	—	—	—	—	—
Extensions	8	22	—	39	—	554	25	187
Infill Drilling	7	10	—	—	—	295	26	92
Improved Recovery	—	1	2	—	—	1	—	3
Acquisitions	8	26	99	50	2,496	145	1	2,704
Dispositions	—	—	—	—	—	(1)	—	—
Economic Factors	1	—	—	—	—	(29)	—	(3)
Technical Revisions	(65)	(11)	3	18	66	185	14	55
Production	(34)	(35)	(19)	(44)	(103)	(607)	(15)	(351)
December 31, 2017	**544**	**272**	**469**	**2,580**	**6,063**	**9,619**	**335**	**11,866**

Reserves Notes:

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

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

(3) BOE values may not calculate due to rounding.

(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2018	2019	2020	2021	2022	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 55.00	$ 65.00	$ 70.00	$ 73.00	$ 74.46	2.00%
Western Canada Select (C$/bbl)	$ 51.05	$ 59.61	$ 64.94	$ 68.43	$ 69.80	2.00%
Canadian Light Sweet (C$/bbl)	$ 65.44	$ 74.51	$ 78.24	$ 82.45	$ 84.10	2.00%
Cromer LSB (C$/bbl)	$ 64.44	$ 73.51	$ 77.24	$ 81.45	$ 83.10	2.00%
Edmonton Pentanes+ (C$/bbl)	$ 67.72	$ 75.61	$ 78.82	$ 82.35	$ 84.07	2.00%
North Sea Brent (US$/bbl)	$ 58.00	$ 67.00	$ 72.00	$ 75.00	$ 76.50	2.00%
Natural gas						
AECO (C$/MMBtu)	$ 2.85	$ 3.11	$ 3.65	$ 3.80	$ 3.95	2.00%
BC Westcoast Station 2 (C$/MMBtu)	$ 2.45	$ 2.71	$ 3.25	$ 3.40	$ 3.55	2.00%
Henry Hub (US$/MMBtu)	$ 3.25	$ 3.50	$ 4.00	$ 4.08	$ 4.16	2.00%

Note: A foreign exchange rate of 0.7900 US$/C$ for 2018, 0.8200 US$/C$ for 2019, and 0.8500 US$/C$ after 2019 was used in the 2017 evaluation.

(5) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 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.

(6) Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.

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

(8) Reserve replacement or Production replacement ratio is the Company Gross reserve additions and revisions, for the relevant reserve category, divided by the Company Gross production in the same period.

(9) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2018 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.

(10) Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 by the sum of total additions and revisions for the relevant reserve category.

(11) FD&A costs including change in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2017 and net change in FDC from December 31, 2016 to December 31, 2017 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.

(12) Recycle Ratio is the operating netback ($23.40/BOE for 2017) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.

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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, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost of 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 its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets, including the interests in AOSP as well as additional working interests in certain other producing and non-producing oil and gas properties (the "other assets"), acquired by the Company on May 31, 2017; 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 national, 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 months and year ended December 31, 2017 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

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 December 31, 2017 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 (loss) from operations, funds flow from operations (previously referred to as 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 (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. 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 and feedstock 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 months and year ended December 31, 2017 in relation to the comparable periods in 2016 and the third quarter of 2017. 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, 2016, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated February 28, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Product sales		**$ 5,323**	$ 4,547	$ 3,672	**$ 17,669**	$ 11,098
Net earnings (loss)		**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Per common share	– basic	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.04**	$ (0.19)
	– diluted	**$ 0.32**	$ 0.56	$ 0.51	**$ 2.03**	$ (0.19)
Adjusted net earnings (loss) from operations (1)		**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)
Per common share	– basic	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
	– diluted	**$ 0.46**	$ 0.19	$ 0.40	**$ 1.19**	$ (0.61)
Funds flow from operations (2)		**$ 2,307**	$ 1,675	$ 1,677	**$ 7,347**	$ 4,293
Per common share	– basic	**$ 1.89**	$ 1.38	$ 1.52	**$ 6.25**	$ 3.90
	– diluted	**$ 1.88**	$ 1.37	$ 1.50	**$ 6.21**	$ 3.89
Net capital expenditures		**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation "Adjusted Net Earnings (Loss) from Operations" presented in this MD&A, 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 (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds 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 "Funds Flow from Operations, as Reconciled to Net Earnings (Loss)" presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended Dec 31 2017	Three Months Ended Sep 30 2017	Three Months Ended Dec 31 2016	Year Ended Dec 31 2017	Year Ended Dec 31 2016
Net earnings (loss) as reported	**$ 396**	$ 684	$ 566	**$ 2,397**	$ (204)
Share-based compensation, net of tax (1)	**97**	114	42	**134**	355
Unrealized risk management loss (gain), net of tax (2)	**68**	(6)	(7)	**33**	21
Unrealized foreign exchange (gain) loss, net of tax (3)	**(2)**	(404)	162	**(821)**	(93)
Gain from investments, net of tax (4) (5)	**(4)**	(76)	(106)	**(11)**	(299)
Gain on acquisition, disposition and revaluation of properties, net of tax (6)	**—**	(83)	(218)	**(339)**	(241)
Derecognition of exploration and evaluation assets,net of tax (7)	**—**	—	—	**—**	13
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**10**	—	—	**10**	(221)
Adjusted net earnings (loss) from operations	**$ 565**	$ 229	$ 439	**$ 1,403**	$ (669)

(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 (loss) or are charged to (recovered from) Oil Sands Mining and Upgrading.

(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 (loss). 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 (loss).

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

(5) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings (loss).

(6) During the third quarter of 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During the second quarter of 2017, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment. During the fourth quarter of 2016, the Company recorded a pre and after-tax gain of $218 million on the disposition of Midstream property, plant and equipment. During the first quarter of 2016, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets.

(7) In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized $18 million ($13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) In the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million. In the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million.

Funds Flow from Operations, as Reconciled to Net Earnings (Loss)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net earnings (loss)	***$ 396***	*$ 684*	*$ 566*	***$ 2,397***	*$ (204)*
Non-cash items:					
Depletion, depreciation and amortization	***1,406***	*1,271*	*1,249*	***5,186***	*4,858*
Share-based compensation	***97***	*114*	*42*	***134***	*355*
Asset retirement obligation accretion	***45***	*44*	*35*	***164***	*142*
Unrealized risk management loss (gain)	***75***	*8*	*(7)*	***37***	*25*
Unrealized foreign exchange (gain) loss	***(2)***	*(404)*	*162*	***(821)***	*(93)*
Gain from investments	***(4)***	*(76)*	*(106)*	***(11)***	*(299)*
Deferred income tax expense (recovery)	***294***	*148*	*(46)*	***640***	*(241)*
Gain on acquisition, disposition and revaluation of properties	**—**	*(114)*	*(218)*	***(379)***	*(250)*
Funds flow from operations	***$ 2,307***	*$ 1,675*	*$ 1,677*	***$ 7,347***	*$ 4,293*

Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Cash flows from operating activities	***$ 1,438***	*$ 2,522*	*$ 1,255*	***$ 7,262***	*$ 3,452*
Net change in non-cash working capital	***709***	*(918)*	*317*	***(299)***	*542*
Abandonment expenditures	***63***	*65*	*35*	***274***	*267*
Other	***97***	*6*	*70*	***110***	*32*
Funds flow from operations	***$ 2,307***	*$ 1,675*	*$ 1,677*	***$ 7,347***	*$ 4,293*

SUMMARY OF CONSOLIDATED NET EARNINGS (LOSS) AND FUNDS FLOW FROM OPERATIONS

Net earnings for the year ended December 31, 2017 were $2,397 million compared with a net loss of $204 million for the year ended December 31, 2016. Net earnings for the year ended December 31, 2017 included net after-tax income of $994 million compared with net after-tax income of $465 million for the year ended December 31, 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, gain from investments, gain on acquisition, disposition and revaluation of properties, the derecognition of exploration and evaluation assets 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 year ended December 31, 2017 were $1,403 million compared with an adjusted net loss of $669 million for the year ended December 31, 2016.

Net earnings for the fourth quarter of 2017 were $396 million compared with a net earnings of $566 million for the fourth quarter of 2016 and net earnings of $684 million for the third quarter of 2017. Net earnings for the fourth quarter of 2017 included net after-tax expenses of $169 million compared with net after-tax income of $127 million for the fourth quarter of 2016 and net after-tax income of $455 million for the third quarter of 2017 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, gain from investments, gain on acquisition, disposition and revaluation 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 fourth quarter of 2017 were $565 million compared with adjusted net earnings of $439 million for the fourth quarter of 2016 and adjusted net earnings of $229 million for the third quarter of 2017.

The increase in adjusted net earnings (loss) for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and new Phase 2B and Phase 3 sales volumes at Horizon;
- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- higher realized risk management gains;

partially offset by:

- lower natural gas netbacks in the North America Exploration and Production segment;
- higher depletion, depreciation and amortization;
- higher interest and financing expense; and
- the strengthening of the Canadian dollar relative to the US dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to:

- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments;
- higher crude oil and NGLs sales volumes in the North America Exploration and Production segment;
- higher realized risk management gains; and
- the weakening of the Canadian dollar relative to the US dollar;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to the planned major turnaround at Horizon and planned pitstops at AOSP; and
- higher depletion, depreciation and amortization.

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

Funds flow from operations for the year ended December 31, 2017 was $7,347 million compared with $4,293 million for the year ended December 31, 2016. Funds flow from operations for the fourth quarter of 2017 was $2,307 million compared with $1,677 million for the fourth quarter of 2016 and $1,675 million for the third quarter of 2017. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss), as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the fourth quarter of 2017 increased 19% to 1,020,094 BOE/d from 859,577 BOE/d for the fourth quarter of 2016 and decreased 2% from 1,036,499 BOE/d for the third quarter of 2017.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)	**Dec 31 2017**	Sep 30 2017	Jun 30 2017	Mar 31 2017
Product sales	**$ 5,323**	$ 4,547	$ 3,927	$ 3,872
Net earnings (loss)	**$ 396**	$ 684	$ 1,072	$ 245
Net earnings (loss) per common share				
– basic	**$ 0.32**	$ 0.56	$ 0.93	$ 0.22
– diluted	**$ 0.32**	$ 0.56	$ 0.93	$ 0.22
($ millions, except per common share amounts)	**Dec 31 2016**	**Sep 30 2016**	**Jun 30 2016**	**Mar 31 2016**
Product sales	$ 3,672	$ 2,477	$ 2,686	$ 2,263
Net earnings (loss)	$ 566	$ (326)	$ (339)	$ (105)
Net earnings (loss) per common share				
– basic	$ 0.51	$ (0.29)	$ (0.31)	$ (0.10)
– diluted	$ 0.51	$ (0.29)	$ (0.31)	$ (0.10)

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries ("OPEC") and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("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 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, third party pipeline maintenance and the impact of 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, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds at Horizon and pitstops at AOSP, shut-in production due to low commodity prices, and the impact of the drilling program in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, an outage at a third party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost 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, including the acquisition of AOSP and other assets, turnarounds at Horizon and pitstops at AOSP, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, 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 International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, 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 predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were 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.
- **Gain on acquisition, disposition and revaluation of properties and gain/loss on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity (gain) loss in North West Redwater.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
WTI benchmark price (US$/bbl)	**$ 55.39**	$ 48.19	$ 49.33	**$ 50.93**	$ 43.37
Dated Brent benchmark price (US$/bbl)	**$ 61.46**	$ 51.76	$ 50.27	**$ 54.38**	$ 43.96
WCS blend differential from WTI (US$/bbl)	**$ 12.28**	$ 9.94	$ 14.59	**$ 11.97**	$ 13.91
SCO price (US$/bbl)	**$ 58.64**	$ 48.83	$ 48.91	**$ 52.20**	$ 43.94
Condensate benchmark price (US$/bbl)	**$ 57.96**	$ 47.96	$ 48.37	**$ 51.65**	$ 42.51
NYMEX benchmark price (US$/MMBtu)	**$ 2.94**	$ 3.00	$ 2.99	**$ 3.11**	$ 2.45
AECO benchmark price (C$/GJ)	**$ 1.85**	$ 1.94	$ 2.67	**$ 2.30**	$ 1.98
US/Canadian dollar average exchange rate (US$)	**$ 0.7865**	$ 0.7983	$ 0.7496	**$ 0.7701**	$ 0.7548

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. The Company’s realized prices are highly sensitive to fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility in the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales 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$50.93 per bbl for the year ended December 31, 2017, an increase of 17% from US$43.37 per bbl for the year ended December 31, 2016. WTI averaged US$55.39 per bbl for the fourth quarter of 2017, an increase of 12% from US$49.33 per bbl for the fourth quarter of 2016, and an increase of 15% from US$48.19 per bbl for the third quarter of 2017.

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$54.38 per bbl for the year ended December 31, 2017, an increase of 24% from US$43.96 per bbl for the year ended December 31, 2016. Brent averaged US$61.46 per bbl for the fourth quarter of 2017, an increase of 22% from US$50.27 per bbl for the fourth quarter of 2016, and an increase of 19% from US$51.76 per bbl for the third quarter of 2017.

WTI and Brent pricing for the three months and year ended December 31, 2017 has increased from the comparable periods due to declines in global crude oil inventories as a result of OPEC’s adherence to previously announced production cuts, together with larger than anticipated increases in global demand for crude oil.

The WCS Heavy Differential averaged US$11.97 per bbl for the year ended December 31, 2017, a decrease of 14% from US$13.91 per bbl for the year ended December 31, 2016. The WCS Heavy Differential averaged US$12.28 per bbl for the fourth quarter of 2017, a decrease of 16% from US$14.59 per bbl for the fourth quarter of 2016, and an increase of 24% from US$9.94 per bbl for the third quarter of 2017. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. The fluctuations in the WCS Heavy Differential for the three months and year ended December 31, 2017 from the comparable periods reflected seasonal supply and demand factors and changes in transportation logistics. Subsequent to December 31, 2017, the WCS Heavy Differential widened due to third party pipeline outages.

The SCO price averaged US$52.20 per bbl for the year ended December 31, 2017, an increase of 19% from US$43.94 per bbl for the year ended December 31, 2016. The SCO price averaged US$58.64 per bbl for the fourth quarter of 2017, an increase of 20% from US$48.91 per bbl for the fourth quarter of 2016, and an increase of 20% from US$48.83 per bbl for the third quarter of 2017. The increase in SCO pricing for the three months and year ended December 31, 2017 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$3.11 per MMBtu for the year ended December 31, 2017, an increase of 27% from US$2.45 per MMBtu for the year ended December 31, 2016. NYMEX natural gas prices averaged US$2.94 per MMBtu for the fourth quarter of 2017, a decrease of 2% from US$2.99 per MMBtu for the fourth quarter of 2016, and a decrease of 2% from US$3.00 per MMBtu for the third quarter of 2017.

AECO natural gas prices averaged $2.30 per GJ for the year ended December 31, 2017, an increase of 16% from $1.98 per GJ for the year ended December 31, 2016. AECO natural gas prices averaged $1.85 per GJ for the fourth quarter of 2017, a decrease of 31% from $2.67 per GJ for the fourth quarter of 2016, and a decrease of 5% from $1.94 per GJ for the third quarter of 2017.

The increase in natural gas prices for the year ended December 31, 2017 compared with the year ended December 31, 2016 primarily reflected the rebalancing of natural gas storage inventory to historically normal levels.

The decrease in AECO natural gas prices in the fourth quarter of 2017 compared with the fourth quarter of 2016 and third quarter of 2017 continued to reflect third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**383,537**	361,216	361,348	**359,449**	350,958
Oil Sands Mining and Upgrading – Horizon (1)	**141,275**	156,465	178,063	**170,089**	123,265
Oil Sands Mining and Upgrading – AOSP	**180,221**	197,900	—	**111,937**	—
North Sea	**19,548**	24,832	24,085	**23,426**	23,554
Offshore Africa	**19,519**	18,776	21,689	**20,335**	26,096
	744,100	759,189	585,185	**685,236**	523,873
Natural gas (MMcf/d)					
North America	**1,596**	1,593	1,578	**1,601**	1,622
North Sea	**37**	46	44	**39**	38
Offshore Africa	**23**	25	24	**22**	31
	1,656	1,664	1,646	**1,662**	1,691
Total barrels of oil equivalent (BOE/d)	**1,020,094**	1,036,499	859,577	**962,264**	805,782
Product mix					
Light and medium crude oil and NGLs	**13%**	13%	15%	**14%**	17%
Pelican Lake heavy crude oil	**6%**	5%	6%	**6%**	6%
Primary heavy crude oil	**10%**	10%	11%	**10%**	13%
Bitumen (thermal oil)	**12%**	11%	15%	**12%**	14%
Synthetic crude oil	**32%**	34%	21%	**29%**	15%
Natural gas	**27%**	27%	32%	**29%**	35%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**92%**	92%	85%	**90%**	85%
Natural gas	**8%**	8%	15%	**10%**	15%

(1) Fourth quarter 2017 SCO production before royalties excludes 1,730 bbl/d of SCO consumed internally as diesel (third quarter 2017 – 0 bbl/d; fourth quarter 2016 – 1,619 bbl/d; year ended December 31, 2017 – 651 bbl/d; year ended December 31, 2016 – 1,966 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**333,698**	310,497	315,090	**312,297**	311,059
Oil Sands Mining and Upgrading – Horizon	**138,435**	154,757	175,860	**167,248**	122,258
Oil Sands Mining and Upgrading – AOSP	**171,342**	190,310	—	**107,189**	—
North Sea	**19,518**	24,784	24,034	**23,382**	23,497
Offshore Africa	**17,885**	17,735	20,730	**19,124**	24,995
	680,878	698,083	535,714	**629,240**	481,809
Natural gas (MMcf/d)					
North America	**1,538**	1,543	1,480	**1,528**	1,559
North Sea	**37**	46	44	**39**	38
Offshore Africa	**20**	22	23	**20**	30
	1,595	1,611	1,547	**1,587**	1,627
Total barrels of oil equivalent (BOE/d)	**946,731**	966,528	793,483	**893,702**	752,974

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 year ended December 31, 2017 increased 31% to 685,236 bbl/d from 523,873 bbl/d for the year ended December 31, 2016. Crude oil and NGLs production for the fourth quarter of 2017 of 744,100 bbl/d increased 27% from 585,185 bbl/d for the fourth quarter of 2016, and decreased 2% from 759,189 bbl/d in the third quarter of 2017. The increase in crude oil and NGLs production for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to acquisitions completed in 2017 and new Phase 2B and Phase 3 production at Horizon. The increase in crude oil and NGLs production for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to acquisitions completed in 2017 and new Phase 3 production at Horizon, partially offset by the planned major turnaround. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 reflected the planned major turnaround at Horizon, planned pitstops at AOSP and the proactive shut-in of thermal and heavy crude oil production related to pricing in late December, partially offset by new Phase 3 production at Horizon in December and the impact of acquisitions in the third quarter of 2017.

Annual 2017 crude oil and NGLs production was within the Company's previously issued guidance of 663,000 to 717,000 bbl/d. First quarter 2018 crude oil and NGLs production guidance is targeted to average between 821,000 and 869,000 bbl/d. Annual crude oil and NGLs production guidance for 2018 is targeted to average between 815,000 and 885,000 bbl/d.

Natural gas production for the year ended December 31, 2017 decreased 2% to 1,662 MMcf/d from 1,691 MMcf/d for the year ended December 31, 2016. Natural gas production for the fourth quarter of 2017 averaged 1,656 MMcf/d, comparable with 1,646 MMcf/d for the fourth quarter of 2016 and 1,664 MMcf/d for the third quarter of 2017. Natural gas production continued to be impacted by low natural gas prices and reliability issues at a third party facility. During the fourth quarter of 2017, the Company shut-in production volumes of 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at the third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

Annual 2017 natural gas production was within the Company's previously issued guidance of 1,655 to 1,705 MMcf/d. First quarter 2018 natural gas production guidance is targeted to average between 1,600 and 1,650 MMcf/d. Annual natural gas production guidance for 2018 is targeted to average between 1,650 and 1,710 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2017 averaged 359,449 bbl/d, an increase of 2% from 350,958 bbl/d for the year ended December 31, 2016. North America crude oil and NGLs production for the fourth quarter of 2017 increased 6% to 383,537 bbl/d from 361,348 bbl/d for the fourth quarter of 2016, and increased 6% from 361,216 bbl/d for the third quarter of 2017. The increase in production for the three months and year ended December 31, 2017 from the comparable periods was primarily due to acquisitions completed in 2017. North America crude oil and NGLs production for the fourth quarter of 2017 also reflected the proactive shut-in of thermal and heavy crude oil production related to pricing in late December.

Annual 2017 crude oil and NGLs production was within the Company's previously issued guidance of 348,000 to 368,000 bbl/d. First quarter 2018 crude oil and NGLs production guidance is targeted to average between 348,000 and 362,000 bbl/d. Annual crude oil and NGLs production guidance for 2018 is targeted to average between 360,000 and 390,000 bbl/d.

Natural gas production for the year ended December 31, 2017 averaged 1,601 MMcf/d, comparable with 1,622 MMcf/d for the year ended December 31, 2016. Natural gas production for the fourth quarter of 2017 averaged 1,596 MMcf/d, comparable with 1,578 MMcf/d for the fourth quarter of 2016 and 1,593 MMcf/d in the third quarter of 2017. Natural gas production continued to be impacted by low natural gas prices and reliability issues at a third party facility. During the fourth quarter of 2017, shut-in production volumes of 24 MMcf/d related to low natural gas prices and 39 MMcf/d related to the impact of reliability issues at the third party facility. As a result of continued integrity issues, capacity at this facility has now been reduced to a one train operation.

Horizon

Horizon SCO production for the year ended December 31, 2017 of 170,089 bbl/d increased 38% from 123,265 bbl/d for the year ended December 31, 2016. Horizon SCO production for the fourth quarter of 2017 decreased 21% to average 141,275 bbl/d from 178,063 bbl/d for the fourth quarter of 2016 and decreased 10% from 156,465 bbl/d for the third quarter of 2017. The increase in production for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected new Phase 2B and Phase 3 production at Horizon. The decrease in production for the fourth quarter of 2017 from the fourth quarter of 2016 and third quarter of 2017 reflected the impact of the planned major turnaround that was completed in the fourth quarter of 2017, followed by the successful ramp-up of Phase 3 production to approximately 247,200 bbl/d in December. Annual 2017 Horizon SCO production was within the Company’s previously issued guidance of 170,000 to 184,000 bbl/d.

Athabasca Oil Sands Project

AOSP achieved annualized SCO production for the year ended December 31, 2017 of 111,937 bbl/d. AOSP SCO production for the fourth quarter of 2017 decreased 9% to average 180,221 bbl/d from 197,900 bbl/d in the third quarter of 2017. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the completion of the planned pitstops at the Jackpine and Muskeg River mines. Annualized 2017 AOSP SCO production was within the Company's previously issued guidance of 102,000 to 116,000 bbl/d.

Oil Sands Mining and Upgrading Guidance

First quarter 2018 Oil Sands Mining and Upgrading SCO production guidance is targeted to average between 435,000 and 465,000 bbl/d. Annual Oil Sands Mining and Upgrading SCO production guidance for 2018 is targeted to average between 415,000 and 450,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2017 averaged 23,426 bbl/d, comparable with 23,554 bbl/d for the year ended December 31, 2016. North Sea crude oil production for the fourth quarter of 2017 decreased 19% to 19,548 bbl/d from 24,085 bbl/d for the fourth quarter of 2016 and decreased 21% from 24,832 bbl/d in the third quarter of 2017. The decrease in production for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to the impact of the shut-in of the Ninian North platform in May 2017 and natural field declines, partially offset by new wells at Ninian South and production optimization. The decrease in production for the fourth quarter of 2017 from the third quarter of 2017 was due to temporary unplanned shut-ins of the Ninian South platform as well as the Forties Pipeline System which impacted the Tiffany platform in December 2017.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2017 decreased 22% to 20,335 bbl/d from 26,096 bbl/d for the year ended December 31, 2016. Offshore Africa crude oil production for the fourth quarter of 2017 decreased 10% to 19,519 bbl/d from 21,689 bbl/d for the fourth quarter of 2016 and increased 4% from 18,776 bbl/d in the third quarter of 2017. The decrease in production for the three months and year ended December 31, 2017 from the comparable periods in 2016 primarily reflected natural field declines. The increase in production for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the resumption of production at Baobab following the successful completion of the planned turnaround during the third quarter of 2017.

International Guidance

Annual 2017 International crude oil production of 43,761 bbl/d was within the Company's previously issued guidance of 43,000 to 49,000 bbl/d. First quarter 2018 international crude oil production guidance is targeted to average between 38,000 and 42,000 bbl/d. Annual international crude oil production guidance for 2018 is targeted to average between 40,000 and 45,000 bbl/d.

International 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 in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016
North Sea	**—**	506,748	987,316
Offshore Africa	**121,936**	639,622	1,126,999
	121,936	1,146,370	2,114,315

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Transportation	**2.82**	2.81	2.70	**2.80**	2.61
Realized sales price, net of transportation	**50.60**	43.52	42.30	**45.77**	34.32
Royalties	**5.84**	5.33	4.62	**5.24**	3.40
Production expense	**15.03**	14.71	14.28	**14.89**	14.10
Netback	**$ 29.73**	$ 23.48	$ 23.40	**$ 25.64**	$ 16.82
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32
Transportation	**0.46**	0.33	0.34	**0.39**	0.33
Realized sales price, net of transportation	**2.09**	1.96	2.80	**2.37**	1.99
Royalties	**0.08**	0.07	0.17	**0.11**	0.09
Production expense	**1.33**	1.22	1.15	**1.27**	1.18
Netback	**$ 0.68**	$ 0.67	$ 1.48	**$ 0.99**	$ 0.72
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 38.78**	$ 33.27	$ 34.54	**$ 35.54**	$ 27.58
Transportation	**2.86**	2.51	2.46	**2.66**	2.44
Realized sales price, net of transportation	**35.92**	30.76	32.08	**32.88**	25.14
Royalties	**3.75**	3.36	3.16	**3.40**	2.21
Production expense	**12.28**	11.73	11.34	**11.95**	11.18
Netback	**$ 19.89**	$ 15.67	$ 17.58	**$ 17.53**	$ 11.75

(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			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 50.51**	$ 43.56	$ 42.56	**$ 45.85**	$ 34.31
North Sea	**$ 76.71**	$ 66.07	$ 63.68	**$ 69.43**	$ 55.91
Offshore Africa	**$ 73.43**	$ 64.14	$ 61.29	**$ 67.15**	$ 54.96
Company average	**$ 53.42**	$ 46.33	$ 45.00	**$ 48.57**	$ 36.93
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.33**	$ 2.07	$ 2.97	**$ 2.58**	$ 2.15
North Sea	**$ 9.77**	$ 7.73	$ 7.75	**$ 8.24**	$ 6.62
Offshore Africa	**$ 6.73**	$ 6.56	$ 5.75	**$ 6.57**	$ 6.13
Company average	**$ 2.55**	$ 2.29	$ 3.14	**$ 2.76**	$ 2.32
Company average ($/BOE) (1) (2)	**$ 38.78**	$ 33.27	$ 34.54	**$ 35.54**	$ 27.58

(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 increased 34% to $45.85 per bbl for the year ended December 31, 2017 from $34.31 per bbl for the year ended December 31, 2016. North America realized crude oil prices averaged $50.51 per bbl for the fourth quarter of 2017, an increase of 19% compared with $42.56 per bbl for the fourth quarter of 2016 and an increase of 16% compared with $43.56 per bbl for the third quarter of 2017. The increase in realized crude oil prices for the three months and year ended December 31, 2017 from the comparable periods in 2016 was primarily due to higher WTI benchmark pricing. The increase in realized crude oil prices for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2017, contributed approximately 190,400 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 20% to average $2.58 per Mcf for the year ended December 31, 2017 from $2.15 per Mcf for the year ended December 31, 2016. North America realized natural gas prices decreased 22% to average $2.33 per Mcf for the fourth quarter of 2017 compared with $2.97 per Mcf for the fourth quarter of 2016, and increased 13% compared with $2.07 per Mcf for the third quarter of 2017. The increase in realized natural gas prices per Mcf for the year ended December 31, 2017 from the year ended December 31, 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels.

The decrease in realized natural gas prices for the fourth quarter of 2017 compared with the fourth quarter of 2016 reflected third party pipeline constraints limiting flow of natural gas to discretionary storage and export markets as well as increased natural gas production in the basin.

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

(Quarterly Average)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 54.09**	$ 43.27	$ 45.05
Pelican Lake heavy crude oil ($/bbl)	**$ 52.44**	$ 45.67	$ 43.96
Primary heavy crude oil ($/bbl)	**$ 50.71**	$ 45.55	$ 43.89
Bitumen (thermal oil) ($/bbl)	**$ 46.58**	$ 41.38	$ 39.39
Natural gas ($/Mcf)	**$ 2.33**	$ 2.07	$ 2.97

(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 increased 24% to average $69.43 per bbl for the year ended December 31, 2017 from $55.91 per bbl for the year ended December 31, 2016. North Sea realized crude oil prices increased 20% to average $76.71 per bbl for the fourth quarter of 2017 from $63.68 per bbl for the fourth quarter of 2016 and increased 16% from $66.07 per bbl for the third quarter of 2017. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 22% to average $67.15 per bbl for the year ended December 31, 2017 from $54.96 per bbl for the year ended December 31, 2016. Offshore Africa realized crude oil prices increased 20% to average $73.43 per bbl for the fourth quarter of 2017 from $61.29 per bbl for the fourth quarter of 2016 and increased 14% from $64.14 per bbl for the third quarter of 2017. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 6.20**	$ 5.84	$ 5.05	**$ 5.69**	$ 3.69
North Sea	**$ 0.12**	$ 0.13	$ 0.13	**$ 0.13**	$ 0.13
Offshore Africa	**$ 6.15**	$ 3.56	$ 2.71	**$ 4.13**	$ 2.31
Company average	**$ 5.84**	$ 5.33	$ 4.62	**$ 5.24**	$ 3.40
Natural gas ($/Mcf) (1)					
North America	**$ 0.07**	$ 0.05	$ 0.17	**$ 0.11**	$ 0.08
Offshore Africa	**$ 0.84**	$ 0.95	$ 0.29	**$ 0.76**	$ 0.28
Company average	**$ 0.08**	$ 0.07	$ 0.17	**$ 0.11**	$ 0.09
Company average ($/BOE) (1)	**$ 3.75**	$ 3.36	$ 3.16	**$ 3.40**	$ 2.21

(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 months and year ended December 31, 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the year ended December 31, 2017 compared with 12% of product sales for the year ended December 31, 2016. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2017 compared with 13% for the fourth quarter of 2016 and 14% for the third quarter of 2017. The increase in royalties for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to higher realized crude oil prices during 2017. The decrease for the fourth quarter of 2017 from the third quarter of 2017 reflected royalty adjustments in the third quarter of 2017 to reflect higher average annual bitumen prices. North America crude oil and NGLs royalties per bbl are anticipated to average 10% to 12% of product sales for 2018.

Natural gas royalties averaged approximately 5% of product sales for the year ended December 31, 2017 compared with 4% of product sales for the year ended December 31, 2016. Natural gas royalties averaged approximately 4% of product sales for the fourth quarter of 2017 compared with 6% for the fourth quarter of 2016 and 3% for the third quarter of 2017. The fluctuations in natural gas royalties for the three months and year ended December 31, 2017 from the comparable periods was primarily due to fluctuations in realized natural gas prices. North America natural gas royalties are anticipated to average 4% to 6% of product sales for 2018.

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 7% for the year ended December 31, 2017, compared with 4% of product sales for the year ended December 31, 2016. Royalty rates as a percentage of product sales averaged approximately 9% for the fourth quarter of 2017, compared with 4% of product sales for the fourth quarter of 2016 and 6% for the third quarter of 2017. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2018.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2017	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 12.84**	$ 12.10	$ 12.13	**$ 12.71**	$ 11.89
North Sea	**$ 44.37**	$ 35.72	$ 41.66	**$ 36.60**	$ 42.47
Offshore Africa	**$ 17.96**	$ 29.24	$ 19.05	**$ 24.07**	$ 18.48
Company average	**$ 15.03**	$ 14.71	$ 14.28	**$ 14.89**	$ 14.10
Natural gas ($/Mcf) [1]					
North America	**$ 1.26**	$ 1.15	$ 1.07	**$ 1.19**	$ 1.12
North Sea	**$ 3.98**	$ 3.09	$ 3.36	**$ 3.37**	$ 3.09
Offshore Africa	**$ 2.26**	$ 2.32	$ 2.68	**$ 2.90**	$ 1.79
Company average	**$ 1.33**	$ 1.22	$ 1.15	**$ 1.27**	$ 1.18
Company average ($/BOE) [1]	**$ 12.28**	$ 11.73	$ 11.34	**$ 11.95**	$ 11.18

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2017 increased 7% to $12.71 per bbl from $11.89 per bbl for the year ended December 31, 2016. North America crude oil and NGLs production expense for the fourth quarter of 2017 of $12.84 per bbl increased 6% from $12.13 per bbl in the fourth quarter of 2016 and increased 6% from $12.10 per bbl for the third quarter of 2017. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. Production expense per barrel for the three months and year ended December 31, 2017 reflected higher maintenance, trucking and other service costs. The increase in production expense per barrel in the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher fuel costs in the Company's thermal areas and higher maintenance, trucking and other service costs. Crude oil and NGLs production expense for 2017 was within annual guidance of $11.50 to $13.50 per bbl. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2018.

North America natural gas production expense for the year ended December 31, 2017 averaged $1.19 per Mcf, an increase of 6% from $1.12 per Mcf for the year ended December 31, 2016. North America natural gas production expense for the fourth quarter of 2017 increased 18% to $1.26 per Mcf from $1.07 per Mcf for the fourth quarter of 2016 and increased 10% from $1.15 per Mcf for the third quarter of 2017. The Company continues to focus on cost control and achieving efficiencies on acquired assets and across the entire asset base. The increase in production expense for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected the impact of higher maintenance and other service costs. The increase for the fourth quarter of 2017 from the third quarter of 2017 reflected seasonality. North America natural gas production expense is anticipated to average $1.00 to $1.20 per Mcf for 2018.

North Sea

North Sea crude oil production expense for the year ended December 31, 2017 decreased 14% to $36.60 per bbl from $42.47 per bbl for the year ended December 31, 2016. North Sea crude oil production expense for the fourth quarter of 2017 increased 7% to $44.37 per bbl from $41.66 per bbl for the fourth quarter of 2016 and increased 24% from $35.72 per bbl in the third quarter of 2017. The decrease for the year ended December 31, 2017 from the year ended December 31, 2016 reflected the Company's continuous focus on cost control, efficiencies and production optimization. The increase in production expense for the fourth quarter of 2017 from the fourth quarter of 2016 and third quarter of 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to temporary unplanned shut-ins as well as fluctuations in the Canadian dollar and the UK pound sterling. As a result, crude oil and NGLs production expense for 2017 was slightly above annual guidance of $33.00 to $36.00 per bbl. North Sea crude oil production expense is anticipated to average $36.00 to $39.00 per bbl for 2018.

Offshore Africa

Offshore Africa crude oil production expense of $24.07 per bbl for the year ended December 31, 2017 included production expense of $12.41 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Production expense of $17.96 per bbl for the fourth quarter of 2017 included production expense of $12.22 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Total Offshore Africa crude oil production expense for the three months and year ended December 31, 2017 primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

On a standalone basis, Offshore Africa production expense for 2017 related to the Baobab and Espoir fields in Côte d'Ivoire was $12.41 per bbl and was within annual guidance of $10.50 to $12.50 per bbl. Offshore Africa production expense related to Côte d'Ivoire is anticipated to average $11.00 to $13.00 per bbl for 2018.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 939**	$ 945	$ 1,049	**$ 3,957**	$ 4,185
$/BOE (1)	**$ 14.46**	$ 14.87	$ 16.71	**$ 15.82**	$ 16.79

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

Depletion, depreciation and amortization on a per barrel basis for the year ended December 31, 2017 decreased 6% to $15.82 per BOE from $16.79 per BOE for the year ended December 31, 2016. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2017 decreased 13% to $14.46 per BOE from $16.71 per BOE for the fourth quarter of 2016 and decreased 3% from $14.87 per BOE for the third quarter of 2017.

The decrease in depletion, depreciation and amortization expense on a per BOE basis for the year ended December 31, 2017 from the year ended December 31, 2016 was primarily due to a lower depletable base in North America, partially offset by additional depletion, depreciation and amortization in the North Sea related to the abandonment of the Ninian North platform. The decrease for the fourth quarter of 2017 from the fourth quarter of 2016 was primarily due to a lower depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended						Year Ended			
($ millions, except per BOE amounts)		**Dec 31 2017**		Sep 30 2017		Dec 31 2016		**Dec 31 2017**		Dec 31 2016
Expense	**$**	**30**	$	29	$	28	**$**	**116**	$	113
$/BOE [1]	**$**	**0.45**	$	0.47	$	0.45	**$**	**0.46**	$	0.45

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2017 of $0.46 per BOE was comparable with $0.45 per BOE for the year ended December 31, 2016. Asset retirement obligation accretion expense for the fourth quarter of 2017 of $0.45 per BOE was comparable with $0.45 per BOE for the fourth quarter of 2016 and $0.47 per BOE for the third quarter of 2017.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

On May 31, 2017 the Company completed the acquisition of a direct and indirect 70% interest in AOSP, including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta and 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project. The acquisition strengthened the Company's portfolio of long life no decline synthetic crude oil assets. Effective May 31, 2017, the Oil Sands Mining and Upgrading segment of this MD&A reflects the mining, extraction and upgrading operations at both Horizon and AOSP.

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved production during the fourth quarter of 2017 averaging 321,496 bbl/d following the addition of new production volumes from the acquisition of and successful integration of the Company's interest in AOSP as well as new Phase 3 production at Horizon, partially offset by the impact of the planned major turnaround which was successfully completed in the fourth quarter of 2017.

Horizon Operations Update

Horizon SCO production averaged 141,275 bbl/d during the fourth quarter of 2017, reflecting the impact of the planned major turnaround partially offset by new Phase 3 production. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional production from new Phase 3, adjusted cash production costs averaging $21.13 per bbl were achieved during the quarter.

The Horizon Phase 3 expansion was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant. SCO production for the month of December averaged approximately 247,200 bbl/d reflecting new Phase 3 production.

AOSP Operations Update

AOSP SCO production averaged 180,221 bbl/d during the fourth quarter of 2017, reflecting the successful completion of the planned pitstops at the Jackpine and Muskeg River Mines. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of AOSP operations, cash production costs of $27.95 per bbl were achieved during the quarter.

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

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Sales Price [2] [3]	**$ 70.85**	$ 56.55	$ 64.51	**$ 63.98**	$ 58.59
Bitumen value for royalty purposes [4]	**$ 44.78**	$ 40.69	$ 35.92	**$ 41.05**	$ 27.57
Bitumen Royalties [5]	**$ 2.45**	$ 1.39	$ 0.88	**$ 1.64**	$ 0.54
Transportation	**$ 1.88**	$ 1.61	$ 1.22	**$ 1.54**	$ 1.77

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

(2) The realized sales price for the periods presented in 2017 reflects the weighted average price of Horizon SCO and AOSP SCO while the realized sales price for the comparable periods in 2016 reflects the Horizon SCO price only. The Horizon realized sales price reflects a premium light sweet SCO compared to the blend at AOSP.

(3) Net of blending and feedstock costs.

(4) Calculated as the quarterly average of the bitumen valuation methodology price.

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $63.98 per bbl for the year ended December 31, 2017, an increase of 9% from $58.59 per bbl for the year ended December 31, 2016. For the fourth quarter of 2017, the realized sales price increased 10% to $70.85 per bbl from $64.51 per bbl for the fourth quarter of 2016 and increased 25% from $56.55 per bbl for the third quarter of 2017. The fluctuations in realized sales prices for the three months and year ended December 31, 2017 from the comparable periods primarily reflected WTI benchmark pricing, together with the impact of new AOSP SCO sales volumes. The increase in realized sales prices for the fourth quarter of 2017 from the third quarter of 2017 reflected WTI benchmark pricing.

The realized SCO sales price for Horizon averaged $67.74 per bbl for the year ended December 31, 2017, an increase of 16% from $58.59 per bbl for the year ended December 31, 2016. For the fourth quarter of 2017, the realized sales price increased 19% to $76.69 per bbl from $64.51 per bbl for the fourth quarter of 2016 and increased 26% from $60.84 per bbl for the third quarter of 2017.

The realized SCO sales price for AOSP averaged $66.36 per bbl for the three months ended December 31, 2017, an increase of 25% from $53.24 per bbl for the third quarter of 2017.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Cash production costs	**$ 846**	$ 829	$ 376	**$ 2,600**	$ 1,292
Less: costs incurred during turnaround periods	**(137)**	(79)	—	**(216)**	(151)
Adjusted cash production costs	**$ 709**	$ 750	$ 376	**$ 2,384**	$ 1,141
Adjusted cash production costs, excluding natural gas costs	**$ 668**	$ 717	$ 336	**$ 2,239**	$ 1,057
Adjusted natural gas costs	**41**	33	40	**145**	84
Adjusted cash production costs	**$ 709**	$ 750	$ 376	**$ 2,384**	$ 1,141

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Adjusted cash production costs, excluding natural gas costs	**$ 23.56**	$ 21.68	$ 20.17	**$ 21.98**	$ 23.36
Adjusted natural gas costs	**1.43**	1.01	2.36	**1.42**	1.84
Adjusted cash production costs	**$ 24.99**	$ 22.69	$ 22.53	**$ 23.40**	$ 25.20
Sales (bbl/d)	**308,067**	359,748	181,523	**279,084**	123,652

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

Adjusted cash production costs for the year ended December 31, 2017 decreased 7% to $23.40 per bbl from $25.20 per bbl for the year ended December 31, 2016. Adjusted cash production costs for the fourth quarter of 2017 averaged $24.99 per bbl, an increase of 11% from $22.53 per bbl for the fourth quarter of 2016 and an increase of 10% from $22.69 per bbl for the third quarter of 2017. The decrease in adjusted cash production costs on a per barrel basis for the year ended December 31, 2017 from the year ended December 31, 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from new Phase 2B and Phase 3 production at Horizon, partially offset by the impact of the acquisition of AOSP. The increase in adjusted cash production costs on a per barrel basis for the fourth quarter of 2017 from the fourth quarter of 2016 primarily reflected the impact of the acquisition of AOSP. The increase for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the planned pitstops at AOSP and unplanned maintenance. For 2018, Oil Sands Mining and Upgrading cash production costs, including turnaround costs, are anticipated to average $22.50 to $26.50 per bbl.

Horizon adjusted cash production costs for the year ended December 31, 2017 decreased 15% to $21.46 per bbl from $25.20 per bbl for the year ended December 31, 2016. Adjusted cash production costs for the fourth quarter of 2017 averaged $21.13 per bbl, a decrease of 6% from $22.53 per bbl for the fourth quarter of 2016 and a 4% increase from $20.24 per bbl for the third quarter of 2017. Cash production costs of $24.98 per bbl for 2017, including turnaround costs, were within the Company's previously issued guidance of $24.00 to $27.00 per bbl.

AOSP annualized cash production costs for the year ended December 31, 2017 were $26.34. Cash production costs for the fourth quarter of 2017 averaged $27.95 per bbl, an increase of 14% from $24.60 per bbl for the third quarter of 2017. Cash production costs for 2017 were below the Company's previously issued guidance of $27.00 to $31.00 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 464**	$ 324	$ 198	**$ 1,220**	$ 662
Less: depreciation incurred during turnaround period	**(188)**	(25)	—	**(213)**	(99)
Adjusted depletion, depreciation and amortization	**$ 276**	$ 299	$ 198	**$ 1,007**	$ 563
$/bbl (1)	**$ 9.75**	$ 9.03	$ 11.84	**$ 9.89**	$ 12.43

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the Oil Sands Mining and Upgrading segment for the year ended December 31, 2017 decreased 20% to $9.89 per bbl from $12.43 per bbl for the year ended December 31, 2016. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2017 decreased 18% to $9.75 per bbl from $11.84 per bbl for the fourth quarter of 2016 and increased 8% from $9.03 per bbl for the third quarter of 2017.

Adjusted depletion, depreciation and amortization expense per barrel for the three months and year ended December 31, 2017 decreased from the comparable periods in 2016 primarily due to the impact of AOSP, which has a lower depletion rate. The increase for the fourth quarter of 2017 from the third quarter of 2017 primarily reflected the impact of assets depreciated on a straight line basis.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Expense	**$ 15**	$ 15	$ 7	**$ 48**	$ 29
$/bbl (1)	**$ 0.53**	$ 0.45	$ 0.44	**$ 0.47**	$ 0.64

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. The increase in asset retirement obligation accretion expense in 2017 reflected the acquisition of AOSP.

Asset retirement obligation accretion expense on a per bbl basis for the year ended December 31, 2017 decreased 27% to $0.47 per bbl from $0.64 per bbl for the year ended December 31, 2016 due to higher sales volumes in 2017. Asset retirement obligation accretion expense of $0.53 per bbl for the fourth quarter of 2017 increased 20% from $0.44 per bbl for the fourth quarter of 2016 and increased 18% from $0.45 per bbl for the third quarter of 2017, primarily due to lower sales volumes in the fourth quarter of 2017.

MIDSTREAM

($ millions)	Three Months Ended **Dec 31 2017**	 Sep 30 2017	 Dec 31 2016	Year Ended **Dec 31 2017**	 Dec 31 2016
Revenue	**$ 28**	$ 26	$ 26	**$ 102**	$ 114
Production expense	**4**	4	5	**16**	25
Midstream cash flow	**24**	22	21	**86**	89
Depreciation	**3**	2	2	**9**	11
Equity loss (gain) on investments	**1**	(20)	12	**(31)**	(7)
Gain on disposition and revaluation of properties (1)	**—**	(114)	(218)	**(114)**	(218)
Segment earnings before taxes	**$ 20**	$ 154	$ 225	**$ 222**	$ 303

(1) During the third quarter of 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During the fourth quarter of 2016, the Company disposed of its interest in the Cold Lake Pipeline including $321 million of property, plant and equipment, for total net consideration of $539 million, resulting in a pre-tax gain of $218 million.

The Company has a 50% interest in the 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 facility capital cost ("FCC") budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

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.

During the second quarter of 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Dec 31 2017**	 Sep 30 2017	 Dec 31 2016	Year Ended **Dec 31 2017**	 Dec 31 2016
Expense	**$ 84**	$ 73	$ 86	**$ 319**	$ 345
$/BOE (1)	**$ 0.90**	$ 0.75	$ 1.08	**$ 0.91**	$ 1.17

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

Administration expense on a per BOE basis for the year ended December 31, 2017 decreased 22% to $0.91 per BOE from $1.17 per BOE for the year ended December 31, 2016. Administration expense for the fourth quarter of 2017 of $0.90 per BOE decreased 17% from $1.08 per BOE for the fourth quarter of 2016 and increased 20% from $0.75 per BOE for the third quarter of 2017. Administration expense per BOE decreased for the three months and year ended December 31, 2017 from the comparable periods in 2016 primarily due to higher overhead recoveries and higher sales volumes. The increase in the fourth quarter of 2017 from the third quarter of 2017 was primarily due to higher staffing and general corporate costs, together with lower sales volumes.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2017	Three Months Ended Sep 30 2017	Three Months Ended Dec 31 2016	Year Ended Dec 31 2017	Year Ended Dec 31 2016
Expense	**$ 97**	$ 114	$ 42	**$ 134**	$ 355

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 $134 million share-based compensation expense for the year ended December 31, 2017, 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. Included within share-based compensation expense for the year ended December 31, 2017 was approximately $5 million related to performance share units granted to certain executive employees (December 31, 2016 – $nil). For the year ended December 31, 2017, the Company charged $14 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (December 31, 2016 – $67 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Dec 31 2017	Three Months Ended Sep 30 2017	Three Months Ended Dec 31 2016	Year Ended Dec 31 2017	Year Ended Dec 31 2016
Expense, gross	**$ 187**	$ 204	$ 153	**$ 713**	$ 616
Less: capitalized interest	**18**	21	38	**82**	233
Expense, net	**$ 169**	$ 183	$ 115	**$ 631**	$ 383
$/BOE (1)	**$ 1.81**	$ 1.90	$ 1.43	**$ 1.79**	$ 1.30
Average effective interest rate	**3.7%**	3.7%	3.8%	**3.8%**	3.9%

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

Gross interest and other financing expense for the three months and year ended December 31, 2017 increased from the comparable periods in 2016 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. The decrease for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to the impact of interest on tax recoveries realized in the fourth quarter of 2017. Capitalized interest of $82 million for the year ended December 31, 2017 was related to the Horizon Phase 3 expansion and the Kirby North project.

Net interest and other financing expense on a per BOE basis for the year ended December 31, 2017 increased 38% to $1.79 per BOE from $1.30 per BOE for the year ended December 31, 2016. Net interest and other financing expense on a per BOE basis for the fourth quarter of 2017 increased 27% to $1.81 per BOE from $1.43 per BOE for the fourth quarter of 2016 and decreased 5% from $1.90 per BOE for the third quarter of 2017. The increase on an absolute and per BOE basis for the three months and year ended December 31, 2017 from the comparable periods in 2016 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 2B and Phase 3. The decrease for the fourth quarter of 2017 from the third quarter of 2017 was primarily due to the impact of interest on tax recoveries in North America, partially offset by lower sales volumes.

The Company's average effective interest rate for the three months and year ended December 31, 2017 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			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Crude oil and NGLs financial instruments	**$ —**	$ (14)	$ —	**$ (32)**	$ —
Natural gas financial instruments	**(2)**	(4)	—	**(7)**	—
Foreign currency contracts	**(71)**	114	(14)	**37**	8
Realized (gain) loss	**(73)**	96	(14)	**(2)**	8
Crude oil and NGLs financial instruments	**7**	66	—	**—**	—
Natural gas financial instruments	**2**	1	8	**(6)**	6
Foreign currency contracts	**66**	(59)	(15)	**43**	19
Unrealized loss (gain)	**75**	8	(7)	**37**	25
Net loss (gain)	**$ 2**	$ 104	$ (21)	**$ 35**	$ 33

During the year ended December 31, 2017, net realized risk management gains were primarily related to the settlement of crude oil price collars and natural gas AECO swaps, offset by the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $37 million ($33 million after-tax) on its risk management activities for the year ended December 31, 2017, including an unrealized loss of $75 million ($68 million after-tax) for the fourth quarter of 2017 (September 30, 2017 – unrealized loss of $8 million, $6 million gain after-tax; December 31, 2016 – unrealized gain of $7 million, $7 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2017 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net realized (gain) loss	**$ (15)**	$ 37	$ (2)	**$ 34**	$ 38
Net unrealized (gain) loss	**(2)**	(404)	162	**(821)**	(93)
Net (gain) loss (1)	**$ (17)**	$ (367)	$ 160	**$ (787)**	$ (55)

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

The net realized foreign exchange loss for the year ended December 31, 2017 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 gain for the year ended December 31, 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2017 – unrealized gain of $1 million, September 30, 2017 – unrealized loss of $50 million, December 31, 2016 – unrealized gain of $67 million; year ended December 31, 2017 – unrealized loss of $280 million, December 31, 2016 – unrealized loss of $295 million). The US/Canadian dollar exchange rate at December 31, 2017 was US$0.7988 (September 30, 2017 – US$0.7994, December 31, 2016 – US$0.7448).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
North America [1]	**$ (93)**	$ (43)	$ (22)	**$ (145)**	$ (377)
North Sea	**10**	11	—	**57**	(74)
Offshore Africa	**17**	14	5	**45**	22
PRT recovery – North Sea	**(25)**	(34)	(35)	**(132)**	(198)
Other taxes	**3**	2	3	**11**	9
Current income tax recovery	**(88)**	(50)	(49)	**(164)**	(618)
Deferred corporate income tax expense (recovery)	**307**	141	(55)	**586**	(106)
Deferred PRT (recovery) expense – North Sea	**(13)**	7	9	**54**	(135)
Deferred income tax expense (recovery)	**294**	148	(46)	**640**	(241)
	206	98	(95)	**476**	(859)
Income tax rate and other legislative changes [2]	**(10)**	—	—	**(10)**	221
	$ 196	$ 98	$ (95)	**$ 466**	$ (638)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**32%**	32%	20%	**27%**	45%

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

(2) During the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million. During the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of $107 million. During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million.

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

The effective income tax rate for the three months and year ended December 31, 2017 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current PRT recovery in the North Sea for the three months and year ended December 31, 2017 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

In October 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 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 reported results of operations, financial position or liquidity.

For 2018, the Company expects to recognize current income tax expense ranging from $300 million to $400 million in Canada and recoveries of $nil to $40 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2017	Sep 30 2017	Dec 31 2016	Year Ended Dec 31 2017	Dec 31 2016
Exploration and Evaluation					
Net expenditures (proceeds) [2] [3] [4]	**$ 16**	$ 66	$ 4	**$ 149**	$ (6)
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**19**	820	1	**1,219**	159
Well drilling, completion and equipping	**212**	241	200	**1,001**	712
Production and related facilities	**258**	241	50	**860**	369
Capitalized interest and other [5]	**27**	22	26	**91**	91
Net expenditures	**516**	1,324	277	**3,171**	1,331
Total Exploration and Production	**532**	1,390	281	**3,320**	1,325
Horizon Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**248**	252	515	**821**	1,920
Sustaining capital	**125**	150	76	**419**	379
Turnaround costs	**65**	73	(3)	**149**	135
Capitalized interest and other [5]	**26**	33	40	**76**	284
Total Horizon Oil Sands Mining and Upgrading	**464**	508	628	**1,465**	2,718
Athabasca Oil Sands Project					
Acquisitions of Exploration and Evaluation assets [2] [4]	**—**	—	—	**219**	—
Net property acquisitions [2] [4]	**—**	—	—	**11,604**	—
Sustaining capital	**89**	45	—	**142**	—
Turnaround costs	**4**	2	—	**6**	—
Total Athabasca Oil Sands Project	**93**	47	—	**11,971**	—
Total Oil Sands Mining and Upgrading	**557**	555	628	**13,436**	2,718
Midstream	**2**	76	(537)	**80**	(533)
Abandonments [6]	**63**	65	35	**274**	267
Head office	**(11)**	8	4	**19**	17
Total net capital expenditures	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794
By segment					
North America [2] [3] [4]	**$ 444**	$ 1,327	$ 221	**$ 3,056**	$ 1,048
North Sea	**52**	32	37	**160**	126
Offshore Africa	**36**	31	23	**104**	151
Oil Sands Mining and Upgrading [4]	**557**	555	628	**13,436**	2,718
Midstream	**2**	76	(537)	**80**	(533)
Abandonments [6]	**63**	65	35	**274**	267
Head office	**(11)**	8	4	**19**	17
Total	**$ 1,143**	$ 2,094	$ 411	**$ 17,129**	$ 3,794

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Includes Business Combinations.

(3) Includes proceeds from the Company's disposition of properties.

(4) In the second quarter of 2017, total purchase consideration for the acquisition of interests in AOSP of $12,157 million includes $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.

(5) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(6) 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.

Net capital expenditures for the year ended December 31, 2017 were $17,129 million compared with $3,794 million for the year ended December 31, 2016. Net capital expenditures for the fourth quarter of 2017 were $1,143 million, compared with $411 million for the fourth quarter of 2016 and $2,094 million for the third quarter of 2017.

Included in net capital expenditures for the year ended December 31, 2017 was $12,157 million related to the acquisition of AOSP and other assets in the second quarter of 2017 and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets in the third quarter of 2017.

On November 7, 2017 the Company announced its 2018 Capital Budget. The budget reflects the Company's transition to a long life low decline asset base with a focus on reliability across the asset base and the continued integration and optimization of acquired assets in 2017. The 2018 budget is targeted at approximately $4,300 million.

Drilling Activity

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2017**	Sep 30 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net successful natural gas wells	**2**	3	4	**21**	9
Net successful crude oil wells (1)	**125**	154	81	**495**	174
Dry wells	**3**	1	3	**7**	7
Stratigraphic test / service wells	**51**	6	62	**289**	268
Total	**181**	164	150	**812**	458
Success rate (excluding stratigraphic test / service wells)	**98%**	99%	97%	**99%**	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 19% of the total net capital expenditures for the year ended December 31, 2017 compared with approximately 20% for the year ended December 31, 2016.

During the fourth quarter of 2017, the Company targeted 2 net natural gas wells in Northwest Alberta. The Company also targeted 128 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 118 primary heavy crude oil wells and 5 bitumen (thermal oil) wells were drilled. Another 5 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the fourth quarter of 2017 averaged approximately 124,100 bbl/d compared with approximately 129,300 bbl/d for the fourth quarter of 2016 and approximately 122,400 bbl/d for the third quarter of 2017. Fourth quarter thermal oil production was within the Company's previously issued guidance.

Pelican Lake production for the fourth quarter of 2017 averaged approximately 65,700 bbl/d compared with 47,500 bbl/d in the fourth quarter of 2016 and 47,600 bbl/d in the third quarter of 2017. Production volumes in the fourth quarter of 2017 reflected the impact of acquisitions in the third quarter of 2017.

Horizon Oil Sands Mining and Upgrading

During the fourth quarter of 2017, Horizon Phase 3 expansion work was completed on schedule and within budget. Phase 3 activities included the expansion tie-in and commissioning of the production plant.

North Sea

During the fourth quarter of 2017, the Company continued to progress the abandonment of the Murchison and Ninian North platforms. Abandonment activities are currently on schedule and within budget.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2017**		Sep 30 2017		Dec 31 2016
Working capital (1)	**$**	**513**	$	205	$	1,056
Long-term debt (2) (3)	**$**	**22,458**	$	22,921	$	16,805
Less: cash and cash equivalents		**137**		312		17
Long-term debt, net	**$**	**22,321**	$	22,609	$	16,788
Share capital	**$**	**9,109**	$	8,844	$	4,671
Retained earnings		**22,612**		22,552		21,526
Accumulated other comprehensive (loss) income		**(68)**		(57)		70
Shareholders' equity	**$**	**31,653**	$	31,339	$	26,267
Debt to book capitalization (3) (4)		**41%**		42%		39%
Debt to market capitalization (3) (5)		**29%**		31%		26%
After-tax return on average common shareholders' equity (6)		**8%**		9%		(1%)
After-tax return on average capital employed (3) (7)		**6%**		6%		0%

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

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

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

(7) Calculated as net earnings (loss) 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 December 31, 2017, the Company’s capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds 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, 2016. In addition, the Company’s ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and 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 funds 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. 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;
- Utilizing funds flow from operations to facilitate debt reduction. Subsequent to December 31, 2017, the Company:
    - extended the fully drawn $750 million non-revolving credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving credit facility;
    - repaid and cancelled $150 million of the $3,000 million non-revolving term loan facility; and
    - repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Reviewing the Company's borrowing capacity:
    - During the second quarter of 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are 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.
    - During the second quarter of 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit 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 December 31, 2017, the $2,200 million facility was fully drawn.
    - In addition to the credit facilities described above, during the second quarter of 2017, the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan 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. The facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn.
    - 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 this program.
    - During the second quarter of 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new 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 August 2019. 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.

- During the second quarter of 2017, the Company repaid US$1,100 million of 5.70% notes. In addition, the Company issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new 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 August 2019. 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.

- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; 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, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

At December 31, 2017, the Company had in place bank credit facilities of $11,050 million, of which approximately $4,112 million was available, resulting in liquidity of $4,249 million, including cash and cash equivalents. This excludes certain other dedicated credit facilities supporting letters of credit.

At December 31, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,753 million (US$10,989 million), before transaction costs and original issue discounts. This included $4,239 million (US$3,389 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,339 million). The fixed repayment amount of these hedging instruments is $4,150 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $89 million to $13,664 million as at December 31, 2017.

Net long-term debt was $22,321 million at December 31, 2017, resulting in a debt to book capitalization ratio of 41% (December 31, 2016 – 39%); 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 funds 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. In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion term loan facility. See note 8 in the unaudited interim consolidated financial statements.

Further details related to the Company's long-term debt at December 31, 2017 are discussed in note 8 to the Company's unaudited interim consolidated financial statements.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support 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. At February 28, 2018 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at December 31, 2017, there were 1,222,769,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 56,036,000 stock options outstanding. As at February 27, 2018, the Company had 1,225,805,000 common shares outstanding and 54,701,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018. On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to $0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to $0.25 per common share (previous quarterly dividend rate of $0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2017, the Company's application was approved for 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, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. For the year ended December 31, 2017, 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. In connection with the acquisition of AOSP and other assets, the Company also assumed certain pipeline and other commitments. The following table summarizes the Company's commitments as at December 31, 2017:

($ millions)	2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 680	$ 584	$ 526	$ 482	$ 422	$ 3,868
Offshore equipment operating leases	$ 181	$ 92	$ 70	$ 68	$ 8	$ —
Long-term debt (1)	$ 2,027	$ 4,228	$ 4,231	$ 760	$ 1,000	$ 10,351
Interest and other financing expense (2)	$ 842	$ 755	$ 638	$ 561	$ 513	$ 5,384
Office leases	$ 43	$ 42	$ 42	$ 39	$ 30	$ 118
Other (3)	$ 87	$ 41	$ 40	$ 39	$ 43	$ 333

(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 payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

(3) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater 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.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. 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, 2016 and the unaudited interim consolidated financial statements for the three months and year ended December 31, 2017.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the annual MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note		**Dec 31 2017**		Dec 31 2016
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**137**	$	17
Accounts receivable			**2,397**		1,434
Current income taxes receivable			**322**		851
Inventory			**894**		689
Prepaids and other			**175**		149
Investments	6		**893**		913
Current portion of other long-term assets	7		**79**		283
			4,897		4,336
Exploration and evaluation assets	3		**2,632**		2,382
Property, plant and equipment	4		**65,170**		50,910
Other long-term assets	7		**1,168**		1,020
		$	**73,867**	$	58,648
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**775**	$	595
Accrued liabilities			**2,597**		2,222
Current portion of long-term debt	8		**1,877**		1,812
Current portion of other long-term liabilities	9		**1,012**		463
			6,261		5,092
Long-term debt	8		**20,581**		14,993
Other long-term liabilities	9		**4,397**		3,223
Deferred income taxes			**10,975**		9,073
			42,214		32,381
SHAREHOLDERS' EQUITY					
Share capital	11		**9,109**		4,671
Retained earnings			**22,612**		21,526
Accumulated other comprehensive income (loss)	12		**(68)**		70
			31,653		26,267
		$	**73,867**	$	58,648

Commitments and contingencies (note 16).

Approved by the Board of Directors on February 28, 2018.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Dec 31 2017**	Three Months Ended Dec 31 2016	Year Ended **Dec 31 2017**	Year Ended Dec 31 2016
Product sales		**$ 5,323**	$ 3,672	**$ 17,669**	$ 11,098
Less: royalties		**(313)**	(214)	**(1,018)**	(575)
Revenue		**5,010**	3,458	**16,651**	10,523
Expenses					
Production		**1,645**	1,092	**5,596**	4,099
Transportation, blending and feedstock		**987**	558	**2,917**	2,003
Depletion, depreciation and amortization	4	**1,406**	1,249	**5,186**	4,858
Administration		**84**	86	**319**	345
Share-based compensation	9	**97**	42	**134**	355
Asset retirement obligation accretion	9	**45**	35	**164**	142
Interest and other financing expense		**169**	115	**631**	383
Risk management activities	15	**2**	(21)	**35**	33
Foreign exchange (gain) loss		**(17)**	160	**(787)**	(55)
Gain on acquisition, disposition and revaluation of properties	3, 4, 5	**—**	(218)	**(379)**	(250)
Gain from investments	6, 7	**(10)**	(111)	**(38)**	(327)
		4,408	2,987	**13,778**	11,586
Earnings (loss) before taxes		**602**	471	**2,873**	(1,063)
Current income tax recovery	10	**(88)**	(49)	**(164)**	(618)
Deferred income tax expense (recovery)	10	**294**	(46)	**640**	(241)
Net earnings (loss)		**$ 396**	$ 566	**$ 2,397**	$ (204)
Net earnings (loss) per common share					
Basic	14	**$ 0.32**	$ 0.51	**$ 2.04**	$ (0.19)
Diluted	14	**$ 0.32**	$ 0.51	**$ 2.03**	$ (0.19)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2017**	Three Months Ended Dec 31 2016	Year Ended **Dec 31 2017**	Year Ended Dec 31 2016
Net earnings (loss)	**$ 396**	$ 566	**$ 2,397**	$ (204)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized (loss) income during the period, net of taxes of $nil (2016 – $2 million) – three months ended; $9 million (2016 – $3 million) – year ended	**(7)**	(14)	**53**	(18)
Reclassification to net earnings (loss), net of taxes of $1 million (2016 – $2 million) – three months ended; $5 million (2016 – $2 million) – year ended	**(4)**	(10)	**(33)**	(13)
	(11)	(24)	**20**	(31)
Foreign currency translation adjustment				
Translation of net investment	**—**	54	**(158)**	26
Other comprehensive income (loss), net of taxes	**(11)**	30	**(138)**	(5)
Comprehensive income (loss)	**$ 385**	$ 596	**$ 2,259**	$ (209)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended **Dec 31 2017**	Dec 31 2016
Share capital	11		
Balance – beginning of year		**$ 4,671**	$ 4,541
Issued for the acquisition of AOSP and other assets [(1)]	5, 11	**3,818**	—
Issued upon exercise of stock options		**466**	559
Previously recognized liability on stock options exercised for common shares		**154**	117
Return of capital on PrairieSky Royalty Ltd. share distribution		**—**	(546)
Balance – end of year		**9,109**	4,671
Retained earnings			
Balance – beginning of year		**21,526**	22,765
Net earnings (loss)		**2,397**	(204)
Dividends on common shares	11	**(1,311)**	(1,035)
Balance – end of year		**22,612**	21,526
Accumulated other comprehensive income (loss)	12		
Balance – beginning of year		**70**	75
Other comprehensive loss, net of taxes		**(138)**	(5)
Balance – end of year		**(68)**	70
Shareholders' equity		**$ 31,653**	$ 26,267

(1) In connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million in the second quarter of 2017. See note 5.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2017	Three Months Ended Dec 31 2016	Year Ended Dec 31 2017	Year Ended Dec 31 2016
Operating activities					
Net earnings (loss)		**$ 396**	$ 566	**$ 2,397**	$ (204)
Non-cash items					
Depletion, depreciation and amortization		**1,406**	1,249	**5,186**	4,858
Share-based compensation		**97**	42	**134**	355
Asset retirement obligation accretion		**45**	35	**164**	142
Unrealized risk management loss (gain)		**75**	(7)	**37**	25
Unrealized foreign exchange (gain) loss		**(2)**	162	**(821)**	(93)
Gain from investments	6, 7	**(4)**	(106)	**(11)**	(299)
Deferred income tax expense (recovery)		**294**	(46)	**640**	(241)
Gain on acquisition, disposition and revaluation of properties	3, 4, 5	**—**	(218)	**(379)**	(250)
Other		**(97)**	(70)	**(110)**	(32)
Abandonment expenditures		**(63)**	(35)	**(274)**	(267)
Net change in non-cash working capital		**(709)**	(317)	**299**	(542)
		1,438	1,255	**7,262**	3,452
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(390)**	(706)	**2,222**	342
Issue of medium-term notes, net	8	**—**	—	**1,791**	998
Issue (repayment) of US dollar debt securities, net	8	**—**	—	**2,733**	(834)
Issue of common shares on exercise of stock options		**186**	238	**466**	559
Dividends on common shares		**(335)**	(254)	**(1,252)**	(758)
		(539)	(722)	**5,960**	307
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets		**(16)**	(4)	**(124)**	6
Net expenditures on property, plant and equipment (1)		**(1,064)**	(642)	**(4,574)**	(3,803)
Acquisition of AOSP and other assets, net of cash acquired (2)	5	**—**	—	**(8,630)**	—
Investment in other long-term assets		**(43)**	—	**(87)**	(99)
Net change in non-cash working capital		**49**	111	**313**	85
		(1,074)	(535)	**(13,102)**	(3,811)
Decrease (increase) in cash and cash equivalents		**(175)**	(2)	**120**	(52)
Cash and cash equivalents – beginning of period		**312**	19	**17**	69
Cash and cash equivalents – end of period		**$ 137**	$ 17	**$ 137**	$ 17
Interest paid, net		**$ 185**	$ 118	**$ 725**	$ 617
Income taxes paid (received)		**$ 12**	$ (4)	**$ (792)**	$ (444)

(1) Net expenditures on property, plant and equipment in the fourth quarter of 2016 exclude non-cash share consideration of $190 million received from Inter Pipeline Ltd ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

(2) The acquisition of AOSP in the second quarter of 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 5.

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 "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in the Athabasca Oil Sands Project ("AOSP").

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, 2016. 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, 2016.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term interests that form part of the net investment in the associate or joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of the amendments on its consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The interpretation is effective January 1, 2019. The Company is assessing the impact of this interpretation on its consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its consolidated financial statements.

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted.

Effective January 1, 2018, the Company retrospectively adopted IFRS 15. Adoption of the new standard did not have a significant impact on the Company's recognition and measurement of revenue; however, it will require certain additional disclosures.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018 and are required to be adopted retrospectively.

The Company adopted the amendment to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2016	$ 2,306	$ —	$ 76	$ —	$ 2,382
Additions	**144**	**—**	**15**	**—**	**159**
Acquisition of AOSP and other assets (note 5)	**31**	**—**	**—**	**259**	**290**
Transfers to property, plant and equipment	**(198)**	**—**	**—**	**—**	**(198)**
Disposals/derecognitions	**(1)**	**—**	**—**	**—**	**(1)**
At December 31, 2017	**$ 2,282**	**$ —**	**$ 91**	**$ 259**	**$ 2,632**

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including exploration and evaluation assets of $290 million. Refer to note 5 regarding the acquisition of AOSP and other assets.

During the year ended December 31, 2017, the Company disposed of certain North America exploration and evaluation assets with a net book value of $1 million for consideration of $36 million, resulting in a pre-tax cash gain on sale of properties of $35 million.

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, 2016	$ 61,647	$ 7,380	$ 5,132	$ 27,038	$ 234	$ 395	$ 101,826
Additions [(1)]	**3,003**	**255**	**101**	**1,660**	**194**	**19**	**5,232**
Acquisition of AOSP and other assets (note 5)	**349**	**—**	**—**	**13,832**	**—**	**—**	**14,181**
Transfers from E&E assets	**198**	**—**	**—**	**—**	**—**	**—**	**198**
Disposals/derecognitions	**(381)**	**—**	**—**	**(446)**	**—**	**—**	**(827)**
Foreign exchange adjustments and other	**—**	**(509)**	**(352)**	**—**	**—**	**—**	**(861)**
At December 31, 2017	**$ 64,816**	**$ 7,126**	**$ 4,881**	**$ 42,084**	**$ 428**	**$ 414**	**$ 119,749**
Accumulated depletion and depreciation							
At December 31, 2016	$ 38,311	$ 5,584	$ 3,797	$ 2,828	$ 115	$ 281	$ 50,916
Expense	**3,220**	**509**	**205**	**1,220**	**9**	**23**	**5,186**
Disposals/derecognitions	**(381)**	**—**	**—**	**(446)**	**—**	**—**	**(827)**
Foreign exchange adjustments and other	**1**	**(440)**	**(283)**	**26**	**—**	**—**	**(696)**
At December 31, 2017	**$ 41,151**	**$ 5,653**	**$ 3,719**	**$ 3,628**	**$ 124**	**$ 304**	**$ 54,579**
Net book value							
- at December 31, 2017	**$ 23,665**	**$ 1,473**	**$ 1,162**	**$ 38,456**	**$ 304**	**$ 110**	**$ 65,170**
- at December 31, 2016	$ 23,336	$ 1,796	$ 1,335	$ 24,210	$ 119	$ 114	$ 50,910

(1) Additions in Midstream include the revaluation of a previously held joint interest in certain pipeline system assets.

Project costs not subject to depletion and depreciation	**Dec 31 2017**	Dec 31 2016
Kirby Thermal Oil Sands – North	**$ 944**	$ 846

On May 31, 2017, the Company completed the acquisition of AOSP and other assets in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, including property, plant and equipment of $14,181 million. Refer to note 5 regarding the acquisition of AOSP and other assets.

During the year ended December 31, 2017, the Company acquired a number of other producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $27 million, along with the remaining interest in certain pipeline system assets in the Midstream segment, for net cash consideration of $1,013 million. These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $63 million. No net deferred income tax liabilities were recognized on these acquisitions.

Further, in connection with the acquisition of pipeline system assets in the Midstream segment, the Company recognized a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in the pipeline.

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 year ended December 31, 2017, pre-tax interest of $82 million (December 31, 2016 – $233 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.8% (December 31, 2016 – 3.9%).

5. ACQUISITION OF INTERESTS IN THE ATHABASCA OIL SANDS PROJECT AND OTHER ASSETS

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments (see note 16). The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company's interests.

Total purchase consideration of $12,541 million, subject to closing adjustments, was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) payable to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion non-revolving term loan facility (see note 8).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, income taxes and foreign exchange rates. The fair value of accounts receivable, inventory, accounts payable and accrued liabilities approximate their carrying values due to the liquid nature of the assets and liabilities.

The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

Cash	$	**93**
Other working capital		**291**
Property, plant and equipment		**14,181**
Exploration and evaluation assets		**290**
Asset retirement obligations		**(721)**
Other long-term liabilities		**(73)**
Deferred income taxes		**(1,287)**
Net assets acquired	$	**12,774**
Total purchase consideration		**12,541**
Gain on acquisition before transaction costs	$	**233**

The Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisitions, revenue increased by $2,872 million to $16,651 million and net operating income (comprised of revenue less production, and transportation, blending, and feedstock expense) increased by $1,166 million to $8,138 million for the year ended December 31, 2017. If the acquisitions had occurred on January 1, 2017, the Company estimates that pro forma revenue would have increased by $2,181 million to $18,832 million and pro forma net operating income would have increased by $735 million to $8,873 million for the year ended December 31, 2017. Readers are cautioned that pro forma revenue and pro forma net operating income are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2017, or of future results. Actual results would have been different and those differences may have been material in comparison to the pro forma information provided. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

6. INVESTMENTS

As at December 31, 2017, the Company had the following investments:

	Dec 31 2017	Dec 31 2016
Investment in PrairieSky Royalty Ltd.	$ 726	$ 723
Investment in Inter Pipeline Ltd.	167	190
	$ 893	$ 913

Investment in PrairieSky Royalty Ltd.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in PrairieSky was classified as a current asset.

The gain from the investment in PrairieSky was comprised as follows:

	Three Months Ended		Year Ended	
	Dec 31 2017	Dec 31 2016	Dec 31 2017	Dec 31 2016
Fair value gain from PrairieSky	$ (4)	$ (118)	$ (3)	$ (292)
Dividend income from PrairieSky	(4)	(4)	(17)	(27)
	$ (8)	$ (122)	$ (20)	$ (319)

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2017, the Company's investment in Inter Pipeline was classified as a current asset.

The (gain) loss from the investment in Inter Pipeline was comprised as follows:

	Three Months Ended		Year Ended	
	Dec 31 2017	Dec 31 2016	Dec 31 2017	Dec 31 2016
Fair value (gain) loss from Inter Pipeline	$ (1)	$ —	$ 23	$ —
Dividend income from Inter Pipeline	(2)	(1)	(10)	(1)
	$ (3)	$ (1)	$ 13	$ (1)

7. OTHER LONG-TERM ASSETS

		Dec 31 2017		Dec 31 2016
Investment in North West Redwater Partnership	**$**	**292**	$	261
North West Redwater Partnership subordinated debt (1)		**510**		385
Risk management (note 15)		**204**		489
Other		**241**		168
		1,247		1,303
Less: current portion		**79**		283
	$	**1,168**	$	1,020

(1) Includes accrued interest.

Investment in North West Redwater Partnership

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership’s voting and decision-making structure and legal form. 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 facility capital cost ("FCC") budget for the Project is currently estimated to be $9,500 million with project completion targeted for third quarter 2018. Productivity challenges during construction have continued to result in upward budgetary pressures that may result in a further increase in FCC of up to 2%. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To December 31, 2017, each party has provided $411 million of subordinated debt, together with accrued interest thereon of $99 million, for a Company total of $510 million. Any additional subordinated debt financing is not expected to be significant.

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.

During the second quarter of 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

As at December 31, 2017, Redwater Partnership had additional borrowings of $1,870 million under its secured $3,500 million syndicated credit facility, maturing June 2018. Subsequent to December 31, 2017, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

During the three months ended December 31, 2017, the Company recognized an equity loss from Redwater Partnership of $1 million (three months ended December 31, 2016 – loss of $12 million; year ended December 31, 2017 – gain of $31 million; year ended December 31, 2016 – gain of $7 million).

8. LONG-TERM DEBT

		Dec 31 2017		Dec 31 2016
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**3,544**	$	2,758
Medium-term notes		**5,300**		3,500
		8,844		6,258
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2017 - US$1,839 million; December 31, 2016 - US$905 million)		**2,300**		1,213
Commercial paper (December 31, 2017 - US$500 million; December 31, 2016 - US$250 million)		**625**		336
US dollar debt securities (December 31, 2017 - US$8,650 million; December 31, 2016 - US$6,750 million)		**10,828**		9,063
		13,753		10,612
Long-term debt before transaction costs and original issue discounts, net		**22,597**		16,870
Less: original issue discounts, net (1)		**18**		10
transaction costs (1) (2)		**121**		55
		22,458		16,805
Less: current portion of commercial paper		**625**		336
current portion of other long-term debt (1) (2)		**1,252**		1,476
	$	**20,581**	$	14,993

(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 December 31, 2017, the Company had in place bank credit facilities of $11,050 million, as described below, of which $4,112 million was available. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,200 million non-revolving term credit facility maturing October 2019;
- a $3,000 million non-revolving term credit facility maturing May 2020;
- a $2,425 million revolving syndicated credit facility maturing June 2020;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the second quarter of 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility continues under the previous terms and matures in June 2019. The other $2,425 million revolving credit facility matures in June 2020. The revolving credit facilities are 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.

During the second quarter of 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit 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 December 31, 2017, the $2,200 million facility was fully drawn.

Borrowings under the $750 million and $125 million non-revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2017, the $750 million and $125 million facilities were each fully drawn. Subsequent to December 31, 2017, the Company extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021 and fully repaid and cancelled the $125 million non-revolving term credit facility.

In addition to the credit facilities described above, during the second quarter of 2017, the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to annual amortization of 5% of the original balance. Borrowings under the term loan 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. This facility also supports a US$375 million letter of credit relating to the deferred purchase consideration payable to Marathon in March 2018. As at December 31, 2017, the $3,000 million facility was fully drawn. Subsequent to December 31, 2017, the Company repaid and cancelled $150 million of the facility; $2,850 million remains outstanding.

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 December 31, 2017 was 2.2% (December 31, 2016 – 1.9%), and on total long-term debt outstanding for the year ended December 31, 2017 was 3.8% (December 31, 2016 – 3.9%).

At December 31, 2017, letters of credit and guarantees aggregating $866 million were outstanding, including letters of credit of $651 million related to AOSP (including the deferred purchase consideration payable to Marathon in March 2018), a $39 million financial guarantee related to Horizon and $63 million of letters of credit related to North Sea operations.

Medium-Term Notes

During the second quarter of 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new 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 August 2019. 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

During the second quarter of 2017, the Company repaid US$1,100 million of 5.70% notes. In addition, the Company issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the debt securities were used to finance the acquisition of AOSP and other assets. In July 2017, the Company filed a new 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 August 2019. 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 December 31, 2017, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

9. OTHER LONG-TERM LIABILITIES

		Dec 31 2017		Dec 31 2016
Asset retirement obligations	$	**4,327**	$	3,243
Share-based compensation		**414**		426
Risk management (note 15)		**103**		—
Other (1)		**565**		17
		5,409		3,686
Less: current portion		**1,012**		463
	$	**4,397**	$	3,223

(1) Included in Other at December 31, 2017 is $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

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 4.7% (December 31, 2016 – 5.2%). Reconciliations of the discounted asset retirement obligations were as follows:

		Dec 31 2017		Dec 31 2016
Balance – beginning of year	$	**3,243**	$	2,950
Liabilities incurred		**12**		3
Liabilities acquired, net		**784**		30
Liabilities settled		**(274)**		(267)
Asset retirement obligation accretion		**164**		142
Revision of cost, inflation rates and timing estimates		**(40)**		(68)
Change in discount rate		**509**		493
Foreign exchange adjustments		**(71)**		(40)
Balance – end of year		**4,327**		3,243
Less: current portion		**92**		95
	$	**4,235**	$	3,148

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 of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered.

		Dec 31 2017		Dec 31 2016
Balance – beginning of year	$	**426**	$	128
Share-based compensation expense		**134**		355
Cash payment for stock options surrendered		**(6)**		(7)
Transferred to common shares		**(154)**		(117)
Charged to Oil Sands Mining and Upgrading, net		**14**		67
Balance – end of year		**414**		426
Less: current portion		**348**		368
	$	**66**	$	58

Included within share-based compensation expense at December 31, 2017 was approximately $5 million (December 31, 2016 - $nil) related to PSUs granted to certain executive employees.

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2017**	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Current corporate income tax – North America	**$ (93)**	$ (22)	**$ (145)**	$ (377)
Current corporate income tax – North Sea	**10**	—	**57**	(74)
Current corporate income tax – Offshore Africa	**17**	5	**45**	22
Current PRT (1) – North Sea	**(25)**	(35)	**(132)**	(198)
Other taxes	**3**	3	**11**	9
Current income tax	**(88)**	(49)	**(164)**	(618)
Deferred corporate income tax	**307**	(55)	**586**	(106)
Deferred PRT (1) – North Sea	**(13)**	9	**54**	(135)
Deferred income tax	**294**	(46)	**640**	(241)
Income tax	**$ 206**	$ (95)	**$ 476**	$ (859)

(1) Petroleum Revenue Tax.

In October 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $10 million.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2017	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,110,952**	**$ 4,671**
Issued for the acquisition of AOSP and other assets (note 5)	**97,561**	**3,818**
Issued upon exercise of stock options	**14,256**	**466**
Previously recognized liability on stock options exercised for common shares	**—**	**154**
Balance – end of year	**1,222,769**	**$ 9,109**

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 February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share. The dividend is payable on April 1, 2018.

Normal Course Issuer Bid

On May 16, 2017, the Company's application was approved for 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, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. For the year ended December 31, 2017, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2017:

	Year Ended Dec 31, 2017		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**58,299**	**$**	**34.22**
Granted	**16,052**	**$**	**42.07**
Surrendered for cash settlement	**(626)**	**$**	**33.18**
Exercised for common shares	**(14,256)**	**$**	**32.66**
Forfeited	**(3,433)**	**$**	**37.53**
Outstanding – end of year	**56,036**	**$**	**36.67**
Exercisable – end of year	**18,282**	**$**	**34.25**

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.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Dec 31 2017		Dec 31 2016
Derivative financial instruments designated as cash flow hedges	**$**	**47**	$	27
Foreign currency translation adjustment		**(115)**		43
	$	**(68)**	$	70

13. 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 net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net 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 December 31, 2017, the ratio was within the target range at 41%.

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.

	Dec 31 2017	Dec 31 2016
Long-term debt, net [(1)]	**$ 22,321**	$ 16,788
Total shareholders' equity	**$ 31,653**	$ 26,267
Debt to book capitalization	**41%**	39%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

14. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Weighted average common shares outstanding – basic (thousands of shares)	**1,219,865**	1,107,181	**1,175,094**	1,100,471
Effect of dilutive stock options (thousands of shares)	**8,547**	11,187	**7,729**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,228,412**	1,118,368	**1,182,823**	1,100,471
Net earnings (loss)	**$ 396**	$ 566	**$ 2,397**	$ (204)
Net earnings (loss) per common share – basic	**$ 0.32**	$ 0.51	**$ 2.04**	$ (0.19)
– diluted	**$ 0.32**	$ 0.51	**$ 2.03**	$ (0.19)

15. FINANCIAL INSTRUMENTS

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

	Dec 31, 2017				
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	**$ 2,397**	**$ —**	**$ —**	**$ —**	**$ 2,397**
Investments	**—**	**893**	**—**	**—**	**893**
Other long-term assets	**510**	**—**	**204**	**—**	**714**
Accounts payable	**—**	**—**	**—**	**(775)**	**(775)**
Accrued liabilities	**—**	**—**	**—**	**(2,597)**	**(2,597)**
Other long-term liabilities (1)	**—**	**(38)**	**(65)**	**(469)**	**(572)**
Long-term debt (2)	**—**	**—**	**—**	**(22,458)**	**(22,458)**
	$ 2,907	**$ 855**	**$ 139**	**$ (26,299)**	**$ (22,398)**

	Dec 31, 2016				
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	$ 1,434	$ —	$ —	$ —	$ 1,434
Investments	—	913	—	—	913
Other long-term assets	385	4	485	—	874
Accounts payable	—	—	—	(595)	(595)
Accrued liabilities	—	—	—	(2,222)	(2,222)
Long-term debt (2)	—	—	—	(16,805)	(16,805)
	$ 1,819	$ 917	$ 485	$ (19,622)	$ (16,401)

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

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

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's investments, recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	Dec 31, 2017			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Investments (3)	**$ 893**	**$ 893**	**$ —**	**$ —**
Other long-term assets (4)	**$ 714**	**$ —**	**$ 204**	**$ 510**
Other long-term liabilities	**$ (103)**	**$ —**	**$ (103)**	**$ —**
Fixed rate long-term debt (5) (6)	**$ (15,989)**	**$ (17,259)**	**$ —**	**$ —**

	Dec 31, 2016			
	Carrying amount	Fair value		
Asset (liability) [(1) (2)]		Level 1	Level 2	Level 3
Investments [(3)]	$ 913	$ 913	$ —	$ —
Other long-term assets [(4)]	$ 874	$ —	$ 489	$ 385
Fixed rate long-term debt [(5) (6)]	$ (12,498)	$ (13,217)	$ —	$ —

(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, and deferred purchase consideration payable to Marathon in March 2018).

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of the investments are based on quoted market prices.

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

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

(6) 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)	**Dec 31 2017**	Dec 31 2016
Derivatives held for trading		
Foreign currency forward contracts	**$ (38)**	$ 10
Natural gas AECO swaps	**—**	(6)
Cash flow hedges		
Foreign currency forward contracts	**(71)**	16
Cross currency swaps	**210**	469
	$ 101	$ 489
Included within:		
Current portion of other long-term (liabilities) assets	**$ (103)**	$ 222
Other long-term assets	**204**	267
	$ 101	$ 489

For the year ended December 31, 2017, the Company recognized a gain of $5 million (year ended December 31, 2016 – gain of $7 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in 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 as applicable, 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 periodically 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 were recognized in the financial statements as follows:

Asset (liability)	**Dec 31 2017**	Dec 31 2016
Balance – beginning of year	**$ 489**	$ 854
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**(37)**	(25)
Foreign exchange	**(375)**	(304)
Other comprehensive income (loss)	**24**	(36)
Balance – end of year	**101**	489
Less: current portion	**(103)**	222
	$ 204	$ 267

Net loss (gain) from risk management activities were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2017	Dec 31 2016	**Dec 31 2017**	Dec 31 2016
Net realized risk management (gain) loss	**$ (73)**	$ (14)	**$ (2)**	$ 8
Net unrealized risk management loss (gain)	**75**	(7)	**37**	25
	$ 2	$ (21)	**$ 35**	$ 33

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 December 31, 2017, the Company had no derivative financial instruments outstanding.

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 December 31, 2017, 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 December 31, 2017, 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	Jan 2018	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2018	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2017 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2017, the Company had US$3,705 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$2,339 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 December 31, 2017, 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 December 31, 2017, the Company had net risk management assets of $187 million with specific counterparties related to derivative financial instruments (December 31, 2016 – $489 million).

The carrying amount of financial assets approximates the maximum credit exposure.

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	$	775	$	—	$	—	$	—
Accrued liabilities	$	2,597	$	—	$	—	$	—
Other long-term liabilities (1)	$	572	$	—	$	—	$	—
Long-term debt (2) (3)	$	2,027	$	4,228	$	5,991	$	10,351

(1) Includes $469 million (US$375 million) of deferred purchase consideration payable to Marathon in March 2018.

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

(3) In addition to the financial liabilities disclosed above, estimated interest and other financing payments related to long-term debt are as follows: less than one year, $842 million; one to less than two years, $755 million; two to less than five years, $1,712 million; and thereafter, $5,384 million. Interest payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2017.

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		2018		2019		2020		2021		2022		Thereafter
Product transportation and pipeline	$	680	$	584	$	526	$	482	$	422	$	3,868
Offshore equipment operating leases	$	181	$	92	$	70	$	68	$	8	$	—
Office leases	$	43	$	42	$	42	$	39	$	30	$	118
Other (1)	$	87	$	41	$	40	$	39	$	43	$	333

(1) In addition to the amounts disclosed above, beginning on the earlier of the commercial operations date of the Redwater 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. See Note 7.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. 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.

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Segmented product sales	**2,592**	2,241	**9,161**	7,209	**215**	168	**784**	570	**184**	163	**632**	603	**2,991**	2,572	**10,577**	8,382
Less: royalties	**(228)**	(192)	**(809)**	(524)	**—**	—	**(1)**	(1)	**(16)**	(8)	**(41)**	(26)	**(244)**	(200)	**(851)**	(551)
Segmented revenue	**2,364**	2,049	**8,352**	6,685	**215**	168	**783**	569	**168**	155	**591**	577	**2,747**	2,372	**9,726**	7,831
Segmented expenses																
Production	**632**	556	**2,362**	2,186	**119**	104	**400**	403	**46**	53	**226**	200	**797**	713	**2,988**	2,789
Transportation, blending and feedstock	**665**	546	**2,291**	1,941	**5**	11	**31**	48	**—**	—	**1**	2	**670**	557	**2,323**	1,991
Depletion, depreciation and amortization	**850**	859	**3,243**	3,465	**37**	143	**509**	458	**52**	47	**205**	262	**939**	1,049	**3,957**	4,185
Asset retirement obligation accretion	**21**	16	**80**	66	**6**	9	**27**	35	**3**	3	**9**	12	**30**	28	**116**	113
Realized risk management activities	**(73)**	(14)	**(2)**	8	**—**	—	**—**	—	**—**	—	**—**	—	**(73)**	(14)	**(2)**	8
Gain on acquisition, disposition and revaluation of properties	**—**	—	**(35)**	(32)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(35)**	(32)
(Gain) loss from investments	**(11)**	(123)	**(7)**	(320)	**—**	—	**—**	—	**—**	—	**—**	—	**(11)**	(123)	**(7)**	(320)
Total segmented expenses	**2,084**	1,840	**7,932**	7,314	**167**	267	**967**	944	**101**	103	**441**	476	**2,352**	2,210	**9,340**	8,734
Segmented earnings (loss) before the following	**280**	209	**420**	(629)	**48**	(99)	**(184)**	(375)	**67**	52	**150**	101	**395**	162	**386**	(903)
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax recovery																
Deferred income tax expense (recovery)																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Segmented product sales	**2,323**	1,079	**7,072**	2,657	**28**	26	**102**	114	**(19)**	(5)	**(82)**	(55)	**5,323**	3,672	**17,669**	11,098
Less: royalties	**(69)**	(14)	**(167)**	(24)	**—**	—	**—**	—	**—**	—	**—**	—	**(313)**	(214)	**(1,018)**	(575)
Segmented revenue	**2,254**	1,065	**6,905**	2,633	**28**	26	**102**	114	**(19)**	(5)	**(82)**	(55)	**5,010**	3,458	**16,651**	10,523
Segmented expenses																
Production	**846**	376	**2,600**	1,292	**4**	5	**16**	25	**(2)**	(2)	**(8)**	(7)	**1,645**	1,092	**5,596**	4,099
Transportation, blending and feedstock	**339**	20	**679**	80	**—**	—	**—**	—	**(22)**	(19)	**(85)**	(68)	**987**	558	**2,917**	2,003
Depletion, depreciation and amortization	**464**	198	**1,220**	662	**3**	2	**9**	11	**—**	—	**—**	—	**1,406**	1,249	**5,186**	4,858
Asset retirement obligation accretion	**15**	7	**48**	29	**—**	—	**—**	—	**—**	—	**—**	—	**45**	35	**164**	142
Realized risk management activities	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(73)**	(14)	**(2)**	8
Gain on acquisition, disposition and revaluation of properties	**—**	—	**(230)**	—	**—**	(218)	**(114)**	(218)	**—**	—	**—**	—	**—**	(218)	**(379)**	(250)
(Gain) loss from investments	**—**	—	**—**	—	**1**	12	**(31)**	(7)	**—**	—	**—**	—	**(10)**	(111)	**(38)**	(327)
Total segmented expenses	**1,664**	601	**4,317**	2,063	**8**	(199)	**(120)**	(189)	**(24)**	(21)	**(93)**	(75)	**4,000**	2,591	**13,444**	10,533
Segmented earnings (loss) before the following	**590**	464	**2,588**	570	**20**	225	**222**	303	**5**	16	**11**	20	**1,010**	867	**3,207**	(10)
Non–segmented expenses																
Administration													**84**	86	**319**	345
Share-based compensation													**97**	42	**134**	355
Interest and other financing expense													**169**	115	**631**	383
Unrealized risk management activities													**75**	(7)	**37**	25
Foreign exchange (gain) loss													**(17)**	160	**(787)**	(55)
Total non–segmented expenses													**408**	396	**334**	1,053
Earnings (loss) before taxes													**602**	471	**2,873**	(1,063)
Current income tax recovery													**(88)**	(49)	**(164)**	(618)
Deferred income tax expense (recovery)													**294**	(46)	**640**	(241)
Net earnings (loss)													**396**	566	**2,397**	(204)

Capital Expenditures (1)

	Year Ended					
	Dec 31, 2017			Dec 31, 2016		
	Net (2) expenditures	**Non-cash and fair value changes (2) (3)**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes (3)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (4)	**$ 160**	**$ (184)**	**$ (24)**	$ 17	$ (211)	$ (194)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**15**	**—**	**15**	9	(18)	(9)
Oil Sands Mining and Upgrading	**142**	**117**	**259**	—	—	—
	$ 317	**$ (67)**	**$ 250**	$ 26	$ (229)	$ (203)
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,815**	**$ 354**	**$ 3,169**	$ 1,143	$ (36)	$ 1,107
North Sea	**160**	**95**	**255**	126	60	186
Offshore Africa	**89**	**12**	**101**	142	(26)	116
	3,064	**461**	**3,525**	1,411	(2)	1,409
Oil Sands Mining and Upgrading (5)	**9,592**	**5,454**	**15,046**	2,718	(23)	2,695
Midstream (6) (7)	**80**	**114**	**194**	(315)	(28)	(343)
Head office	**19**	**—**	**19**	17	—	17
	$ 12,755	**$ 6,029**	**$ 18,784**	$ 3,831	$ (53)	$ 3,778

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

(2) Net expenditures on exploration and evaluation assets and property, plant and equipment for the year ended December 31, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.

(3) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.

(4) The above noted figures for 2017 do not include the impact of a pre-tax cash gain of $35 million (2016 - $32 million pre-tax cash gain) on the disposition of certain exploration and evaluation assets.

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

(6) The above noted figures in 2016 do not include a pre-tax cash and non-cash gain of $218 million on the disposition of certain Midstream assets to Inter Pipeline.

(7) The above noted figures for 2017 include the impact of a pre-tax non-cash revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

Segmented Assets

	Dec 31 2017	Dec 31 2016
Exploration and Production		
North America	**$ 28,705**	$ 28,892
North Sea	**1,854**	2,269
Offshore Africa	**1,331**	1,580
Other	**29**	29
Oil Sands Mining and Upgrading	**40,559**	24,852
Midstream	**1,279**	912
Head office	**110**	114
	$ 73,867	$ 58,648

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 July 2017. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2017:	
Interest coverage (times)	
Net earnings (1)	5.0x
Funds flow from operations (2)	11.1x

(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) Funds 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.

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Corporate Information

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Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ
New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

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