Exhibit 99.2

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED JUNE 30, 2018

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated July 25, 2018, should be read in conjunction with our June 30, 2018 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2017 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2017 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 25, 2018, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Debt, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Notes 1 and 8 of our interim Consolidated Financial Statements. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating Results, Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On June 30, 2018 we had an enterprise value of approximately $26 billion. Operations include oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged nearly 519,000 BOE per day for the three months ended June 30, 2018. We also conduct marketing activities and have refining operations in the United States ("U.S."). The refining operations processed an average of 464,000 gross barrels per day of crude oil feedstock into an average of 490,000 gross barrels per day of refined products in the three months ended June 30, 2018.

Our strategy is focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. We will maintain financial discipline, while balancing growth with shareholder returns. We plan to achieve the goals of our strategy by demonstrating capital discipline, continuing to advance our operational performance, and upholding our trusted reputation.

Our Operations

Oil Sands

Our oil sands assets include steam-assisted gravity drainage ("SAGD") oil sands projects in northeast Alberta, including Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects are located in the Athabasca region of northeastern Alberta. Our project at Telephone Lake is located within the Borealis region of northeastern Alberta. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Deep Basin

Our Deep Basin operations include liquids rich natural gas, condensate and other NGLs, and light and medium oil assets located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities (collectively, the "Deep Basin Assets"). The Deep Basin Assets provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. A portion of the natural gas produced is used as fuel in our oil sands operations and provides an economic hedge for the natural gas required as a fuel source at our refining operations.

Refining and Marketing

Our operations include two refineries located in the United States in Illinois and Texas that are jointly owned with (50 percent interest) and operated by Phillips 66, an unrelated U.S. public company. The combined gross crude oil capacity at the Wood River refinery and Borger refinery (the "Refineries") is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. This includes processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations.

This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Operating Margin Net of Related Capital Investment

	Six Months Ended June 30, 2018		
($ millions)	Oil Sands	Deep Basin	Refining and Marketing
Operating Margin	582	177	309
Capital Investment	542	171	88
Operating Margin Net of Related Capital Investment	**40**	**6**	**221**

QUARTERLY HIGHLIGHTS

Cenovus achieved strong operating and financial results in the second quarter of 2018.

Operational performance continued to be very good during the quarter, following the solid start to 2018. Production from continuing operations averaged 518,530 BOE per day, up six percent from the first quarter of 2018. Oil sands production rose as a result of increased production well rates at Foster Creek and Christina Lake following our decision to restrict crude oil volumes produced in the first quarter in response to pipeline capacity constraints and discounted heavy oil prices. As light-heavy crude oil price differentials narrowed in the second quarter of 2018, we increased production well rates in order to produce those barrels into a stronger crude oil price environment. This demonstrates our ability to use the storage capacity of our oil sands reservoirs to mitigate price fluctuations and maximize the value we capture for our barrels. Production from our Deep Basin Assets also improved, increasing for the fourth consecutive quarter. Following the completion of major planned turnarounds at the Refineries that began in the first quarter, crude utilization increased, averaging 101 percent during the second quarter.

Financial results for the quarter reflect the strong operational performance of our assets and an improvement in crude oil prices to levels not seen since 2014. Increasing West Texas Intermediate ("WTI") crude oil prices and the narrowing of the differential between WTI and Western Canadian Select ("WCS") benchmark prices contributed to our average realized liquids sales price from continuing operations reaching $50.93 per barrel, a 45 percent increase from the first quarter of 2018. Our financial results were negatively impacted by realized risk management losses of $697 million largely as a result of hedging contracts established to provide downside protection and support financial resilience following the Acquisition. The majority of these hedging contracts have expired, with only 37 percent of our anticipated liquids production hedged in the second half of 2018 compared with 80 percent hedged for the first six months of the year.

Compared with 2017, production increased primarily due to the acquisition from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") of the remaining 50 percent interest in the FCCL Partnership ("FCCL") and the Deep Basin Assets on May 17, 2017 ("the Acquisition"). Our financial results were also significantly impacted by condensate costs increasing from 2017, consistent with the rise in light oil prices, and wider light-heavy crude oil price differentials as a result of market access constraints and increasing heavy oil production in Alberta.

Other highlights in the second quarter of 2018 compared with the second quarter of 2017 include:

- Increasing oil sands volumes by 18 percent at Foster Creek and seven percent at Christina Lake, excluding the impact of the Acquisition, as strong operational performance and increased production well rates allowed us to recover the majority of volumes stored in the first quarter of 2018;
- Increasing production from the Deep Basin Assets by eight percent to 129,066 BOE per day compared with 119,273 BOE per day for the 45 days we owned the assets in the second quarter of 2017;
- Earning an average companywide Netback from continuing operations of $29.06 per BOE, before realized hedging, up 46 percent from the second quarter of 2017;
- Recording a net loss from continuing operations of $410 million compared with net earnings of $2,558 million in 2017. Net earnings in 2017 included an after-tax revaluation gain of $1.9 billion on our pre-existing interest in FCCL;
- Recording Adjusted Funds Flow of $774 million compared with $745 million in 2017;
- Investing $292 million in capital compared with $327 million in 2017, reflecting the disposition of our Conventional segment and a continued focus on capital discipline;
- Achieving record monthly crude oil runs at both the Wood River and Borger refineries during the quarter, and benefiting from wider crude oil price differentials, creating a feedstock cost advantage.

OPERATING RESULTS

Upstream Production Volumes

	Three Months Ended June 30, 2018	Percent Change	2017	Six Months Ended June 30, 2018	Percent Change	2017
Continuing Operations						
Liquids (barrels per day)						
Oil Sands						
Foster Creek	**171,079**	**59**	107,859	**164,273**	**74**	94,437
Christina Lake	**218,299**	**42**	153,953	**210,332**	**65**	127,442
	389,378	**49**	261,812	**374,605**	**69**	221,879
Deep Basin						
Crude Oil	**6,263**	**105**	3,059	**6,389**	**315**	1,538
NGLs	**27,778**	**101**	13,835	**28,367**	**308**	6,956
	34,041	**101**	16,894	**34,756**	**309**	8,494
Liquids Production (barrels per day)	**423,419**	**52**	278,706	**409,361**	**78**	230,373
Natural Gas (MMcf per day)						
Oil Sands	**1**	**(92)**	12	**2**	**(85)**	13
Deep Basin [(1)]	**570**	**125**	253	**560**	**341**	127
	571	**115**	265	**562**	**301**	140
Production From Continuing Operations (BOE per day)	**518,530**	**61**	322,792	**503,083**	**98**	253,756
Production From Discontinued Operations (Conventional) (BOE per day)	**79**	**(100)**	114,137	**585**	**(99)**	112,800
Total Production (BOE per day)	**518,609**	**19**	436,929	**503,668**	**37**	366,556

(1) Includes production used for internal consumption by the Oil Sands segment of 300 MMcf per day and 311 MMcf per day, respectively, for the three and six months ended June 30, 2018 (2017 – no internal usage of Deep Basin production).

Production at Foster Creek and Christina Lake was higher in 2018 compared with 2017 primarily due to the Acquisition. Production levels in the second quarter of 2018 also benefited from increased production well rates following our decision to reduce volumes produced in the first quarter of 2018 and leave producible barrels in our reservoirs due to takeaway capacity constraints and discounted heavy crude oil prices. As the light-heavy crude oil price differentials narrowed in the second quarter of 2018, we increased production well rates at our Oil Sands facilities, producing those stored barrels into a stronger crude oil price environment. In the second quarter of 2017, production was reduced by 11,073 barrels per day due to a major planned turnaround at Foster Creek.

Total production from the Deep Basin Assets averaged 129,066 BOE per day in the second quarter of 2018, with three net horizontal wells being brought on production in the quarter. Total production from May 17, 2017 to June 30, 2017, averaged 119,273 BOE per day, equivalent to 58,981 BOE per day for the three months ended June 30, 2017, and 29,654 BOE per day for the six months ended June 30, 2017.

Production for the six months ended June 30, 2018 from our Conventional segment includes the results of our Suffield operations, which were sold on January 5, 2018. All references to our legacy Conventional segment are accounted for as a discontinued operation.

Netbacks From Continuing Operations

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis, and is defined in the Canadian Oil and Gas Evaluation Handbook. Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect the non-cash writedowns of product inventory until the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

	Three Months Ended June 30,		Six Months Ended June 30,	
($/BOE)	**2018**	2017	**2018**	2017
Sales Price	**46.87**	36.31	**40.30**	36.83
Royalties	**4.55**	1.50	**3.49**	1.59
Transportation and Blending	**5.59**	5.78	**5.86**	5.73
Operating Expenses	**7.66**	9.13	**7.77**	9.09
Production and Mineral Taxes	**0.01**	-	**0.01**	-
Netback Excluding Realized Risk Management (1)	**29.06**	19.90	**23.17**	20.42
Realized Risk Management Gain (Loss)	**(16.27)**	0.49	**(14.07)**	(1.41)
Netback Including Realized Risk Management (1)	**12.79**	20.39	**9.10**	19.01

(1) Excludes results from our Conventional segment, which has been classified as a discontinued operation. Excludes intersegment sales.

Our average Netback increased in the second quarter of 2018 and on a year-to-date basis, excluding realized risk management gains and losses, compared with 2017 primarily due to higher realized sales prices, consistent with the rise in benchmark prices, and lower operating costs, partially offset by increased royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. On a year-to-date basis, the strengthening of the Canadian dollar relative to the U.S. dollar compared with 2017 had a negative impact on our sales price of approximately $1.77 per BOE.

Refining and Marketing

Following the completion of major planned turnarounds that began in the first quarter of 2018, both refineries achieved record monthly crude utilization rates during the second quarter. Crude oil runs and refined product output increased compared with the second quarter of 2017, and declined on a year-to-date basis due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2018 compared with 2017.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	**Percent Change**	2017	**2018**	**Percent Change**	2017
Crude Oil Runs (1) (Mbbls/d)	**464**	**3**	449	**407**	**(5)**	428
Heavy Crude Oil (1)	**203**	**1**	201	**183**	**(9)**	201
Refined Product (1) (Mbbls/d)	**490**	**3**	476	**430**	**(5)**	455
Crude Utilization (1) (percent)	**101**	**3**	98	**88**	**(5)**	93

(1) Represents 100 percent of the Wood River and Borger refinery operations.

Operating Margin from Refining and Marketing in the three and six months ended June 30, 2018 was $357 million and $309 million, respectively (2017 – $20 million and $73 million, respectively). Our Operating Margin improved primarily due to increased gross margin, consistent with wider light-heavy crude oil price differentials and higher average market crack spreads. However, for the six months ended June 30, 2018, this was partially offset by higher operating costs and lower crude utilization due to the planned turnarounds at both refineries in the first quarter of 2018.

Further information on the changes in our production volumes, items included in our Netbacks and refining results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [(1)]

	Six Months Ended June 30,					
(US$/bbl, unless otherwise indicated)	**2018**	**Percent Change**	2017	**Q2 2018**	Q1 2018	Q2 2017
Brent						
Average	**71.04**	**35**	52.79	**74.90**	67.18	50.92
End of Period	**79.44**	**66**	47.92	**79.44**	70.27	47.92
WTI						
Average	**65.37**	**30**	50.10	**67.88**	62.87	48.29
End of Period	**74.15**	**61**	46.04	**74.15**	64.94	46.04
Average Differential Brent-WTI	**5.67**	**111**	2.69	**7.02**	4.31	2.63
WCS						
Average	**43.60**	**17**	37.25	**48.61**	38.59	37.16
Average (C$/bbl)	**55.70**	**12**	49.67	**62.75**	48.79	49.95
End of Period	**51.32**	**41**	36.36	**51.32**	42.88	36.36
Average Differential WTI-WCS	**21.77**	**69**	12.85	**19.27**	24.28	11.13
Condensate (C5 @ Edmonton)						
Average	**65.93**	**31**	50.35	**68.83**	63.04	48.44
Average (C$/bbl)	**84.20**	**25**	67.13	**88.81**	79.70	65.11
Average Differential WTI-Condensate (Premium)/Discount	**(0.56)**	**124**	(0.25)	**(0.95)**	(0.17)	(0.15)
Average Differential WCS-Condensate (Premium)/Discount	**(22.33)**	**70**	(13.10)	**(20.22)**	(24.45)	(11.28)
Mixed Sweet Blend ("MSW" @ Edmonton)						
Average	**59.70**	**26**	47.20	**62.42**	56.98	46.03
Average (C$/bbl)	**76.25**	**21**	62.93	**80.54**	72.04	61.87
End of Period	**64.32**	**47**	43.66	**64.32**	60.63	43.66
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**79.04**	**25**	63.28	**85.00**	73.08	63.44
Chicago Ultra-low Sulphur Diesel ("ULSD")	**85.21**	**35**	63.02	**89.07**	81.35	62.18
Refining Margin: Average 3-2-1 Crack Spreads [(2)]						
Chicago	**15.66**	**19**	13.16	**18.36**	12.96	14.78
Group 3	**16.85**	**23**	13.73	**18.04**	15.66	14.27
Average Natural Gas Prices						
AECO (C$/Mcf) [(3)]	**1.44**	**(50)**	2.86	**1.03**	1.85	2.77
NYMEX (US$/Mcf)	**2.90**	**(11)**	3.25	**2.80**	3.00	3.18
Basis Differential NYMEX-AECO (US$/Mcf)	**1.76**	**57**	1.12	**2.00**	1.52	1.13
Foreign Exchange Rate (US$ per C$1)						
Average	**0.783**	**4**	0.750	**0.775**	0.791	0.744
End of Period	**0.759**	**(2)**	0.771	**0.759**	0.776	0.771

(1) *These benchmark prices are not our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks tables in the Operating Results and Reportable Segments sections of this MD&A.*

(2) *The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.*

(3) *Alberta Energy Company ("AECO") natural gas monthly index.*

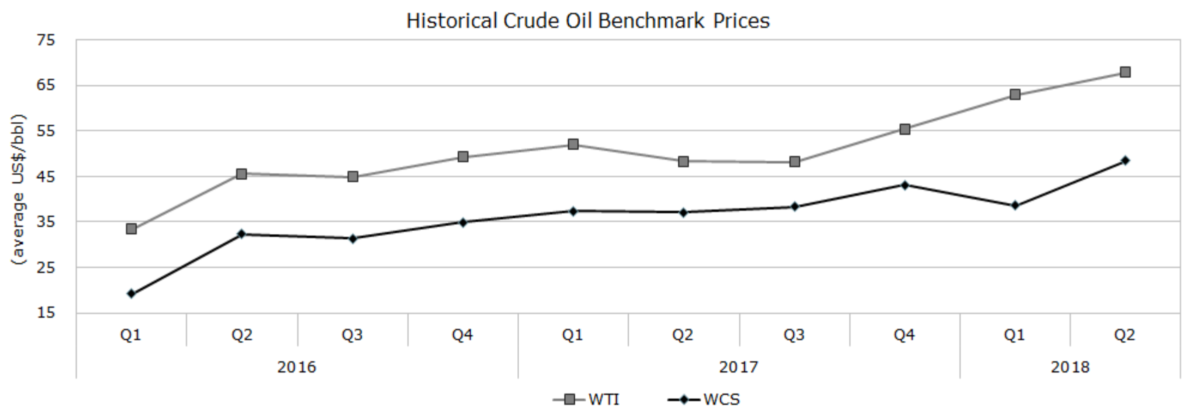
Crude Oil Benchmarks

In the second quarter of 2018, average crude oil benchmark prices increased to levels not seen since 2014. Continued uncertainty over international supply and the possibility of the U.S. enforcing sanctions on Iran supported improved crude oil benchmark pricing over the first six months of 2018 compared with the same period of 2017. Reduced inventory levels from compliance with production cuts outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries ("OPEC") and Russia have supported global oil prices. However, late in June 2018, OPEC agreed to scale back over-compliance with production cuts by its members, which is expected to result in a modest increase in production.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In the second quarter of 2018 and on a year-to-date basis, the Brent-WTI differential widened significantly compared with

2017. Increased production from the Permian Basin exceeded available pipeline capacity out of west Texas, leading to increased volumes moving from Cushing, Oklahoma to the U.S. Gulf Coast on pipelines that were already nearing capacity.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was significantly wider in the second quarter of 2018 and on a year-to-date basis compared with 2017. In early 2018, the WTI-WCS differential widened to levels not seen since the fourth quarter of 2013 as WCS weakened relative to WTI due to increasing production in Alberta and limited takeaway capacity. Canadian heavy oil prices improved in the second quarter as production declined from planned maintenance and temporary producer cuts due to insufficient pipeline takeaway capacity, and the inability to transport additional volumes by rail in the short term.



Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost to transport the condensate to Edmonton.

Average condensate prices were at a larger premium relative to WTI in the second quarter and on a year-to-date basis compared with 2017 due to incremental demand for diluent as a result of increasing Alberta heavy oil production and minimal spare capacity on pipelines that increased the cost of transporting condensate to Edmonton.

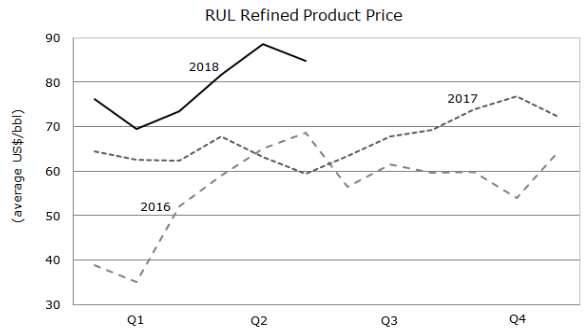
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price improved in 2018 compared with 2017, consistent with the general increase in average crude oil prices.

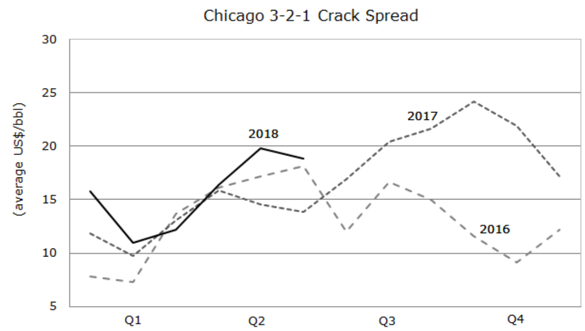
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 crack spread. The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago refined product prices increased in 2018 primarily due to higher crude oil prices and increasing seasonal demand through the second quarter. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by international prices, the strength of refining crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices. The widening of the Chicago 3-2-1 and Group 3 crack spreads in 2018 can be primarily attributed to the widening of the Brent-WTI differential, as discussed above.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average AECO prices weakened during the three and six months ended June 30, 2018 compared with 2017 due to higher natural gas supply in Alberta and reduced export capabilities. Average NYMEX prices also decreased compared with the first six months of 2017 with supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. In addition to our revenues being denominated in U.S. dollars, our long-term debt is also U.S. dollar denominated. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In 2018 the Canadian dollar strengthened relative to the U.S. dollar on average, compared with 2017. This had a negative impact of approximately $458 million on our revenues in the first half of the year, excluding our Conventional segment. The Canadian dollar as at June 30, 2018 compared with December 31, 2017 was weaker relative to the U.S. dollar, resulting in $477 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

In 2018, the primary drivers of our financial results include the impact of the Acquisition, rising light oil benchmark prices, higher condensate prices, significantly wider light-heavy crude oil price differentials and realized risk management losses. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	**Six Months Ended June 30, 2018**	**Six Months Ended June 30,** 2017	**2018 Q2**	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2
Revenues	**10,442**	7,578	**5,832**	4,610	5,079	4,386	4,037	3,541	3,324	2,945	2,746
Operating Margin (1)											
From Continuing Operations	**1,068**	877	**911**	157	1,018	1,097	572	305	442	335	424
Total Operating Margin	**1,107**	1,181	**938**	169	1,088	1,214	731	450	595	487	541
Cash From Operating Activities											
From Continuing Operations	**372**	1,297	**506**	(134)	833	481	1,102	195	22	189	121
Total Cash From Operating Activities	**410**	1,567	**533**	(123)	900	592	1,239	328	164	310	205
Adjusted Funds Flow (2)											
From Continuing Operations	**694**	786	**747**	(53)	796	865	603	183	382	296	352
Total Adjusted Funds Flow	**733**	1,068	**774**	(41)	866	980	745	323	535	422	440
Operating Earnings (Loss) (2)											
From Continuing Operations	**(1,044)**	259	**(292)**	(752)	(533)	240	298	(39)	21	(40)	(3)
Per Share ($) (3)	**(0.85)**	0.27	**(0.24)**	(0.61)	(0.43)	0.20	0.27	(0.05)	0.03	(0.05)	-
Total Operating Earnings (Loss)	**(1,015)**	313	**(272)**	(743)	(514)	327	352	(39)	321	(236)	(39)
Per Share ($) (3)	**(0.83)**	0.32	**(0.22)**	(0.60)	(0.42)	0.27	0.32	(0.05)	0.39	(0.28)	(0.05)
Net Earnings (Loss)											
From Continuing Operations	**(1,324)**	2,769	**(410)**	(914)	(776)	275	2,558	211	(209)	(55)	(231)
Per Share ($) (3)	**(1.08)**	2.84	**(0.33)**	(0.74)	(0.63)	0.22	2.30	0.25	(0.25)	(0.07)	(0.28)
Total Net Earnings (Loss)	**(1,072)**	2,828	**(418)**	(654)	620	(82)	2,617	211	91	(251)	(267)
Per Share ($) (3)	**(0.87)**	2.90	**(0.34)**	(0.53)	0.50	(0.07)	2.35	0.25	0.11	(0.30)	(0.32)
Capital Investment (4)											
From Continuing Operations	**816**	502	**294**	522	557	396	277	225	202	167	202
Total Capital Investment	**816**	640	**292**	524	583	438	327	313	259	208	236
Dividends	**122**	102	**62**	60	61	62	61	41	42	41	42
Per Share ($)	**0.10**	0.10	**0.05**	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

(1) Additional subtotal found in Notes 1 and 8 of the interim Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Represented on a basic and diluted per share basis.
(4) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets and assets held for sale.

Revenues

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2017	**4,037**	**7,578**
Increase (Decrease) due to:		
Oil Sands	**1,439**	**2,752**
Deep Basin	**109**	**333**
Refining and Marketing	**380**	**8**
Corporate and Eliminations	**(133)**	**(229)**
Revenues for the Periods Ended June 30, 2018	**5,832**	**10,442**

Upstream revenues from continuing operations increased significantly compared with 2017. The rise was primarily related to incremental sales volumes and higher average realized pricing, consistent with the rise in crude oil benchmark prices. This was partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar and higher royalties.

Revenues from our Refining and Marketing segment increased 16 percent in the second quarter of 2018 compared with 2017 and were relatively flat on a year-to-date basis. Refining revenues increased due to higher refined product pricing, consistent with the rise in average Chicago refined product benchmark prices, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. Year-to-date results were also impacted by the major planned turnarounds in the first quarter of 2018. Although refining revenues increased in both the second quarter and first half of 2018, lower revenues from our marketing activities largely offset the increase on a year-to-date basis. Revenues from third party crude oil and natural gas sales undertaken by our marketing group decreased in 2018 compared with 2017 due to a decline in crude oil and natural gas volumes sold, as well as lower natural gas prices, partially offset by higher crude oil prices.

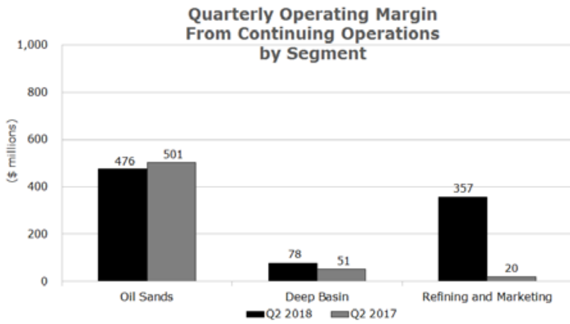
Corporate and Eliminations revenues relate to sales of natural gas or crude oil and operating revenue between segments and are recorded at transfer prices based on current market prices.

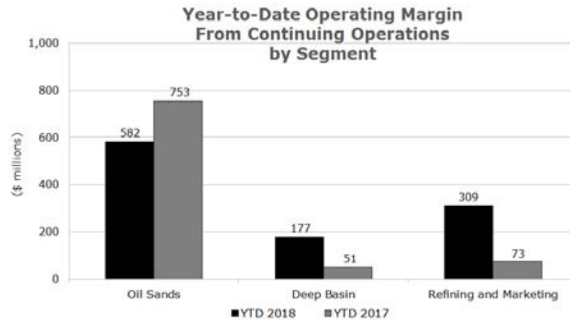
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Margin

Operating Margin is an additional subtotal found in Notes 1 and 8 of the interim Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Revenues	**6,071**	4,143	**10,875**	7,782
(Add) Deduct:				
Purchased Product	**2,224**	2,183	**4,181**	4,513
Transportation and Blending	**1,669**	889	**3,186**	1,455
Operating Expenses	**569**	511	**1,274**	870
Production and Mineral Taxes	**1**	-	**1**	-
Realized (Gain) Loss on Risk Management Activities	**697**	(12)	**1,165**	67
Operating Margin From Continuing Operations	**911**	572	**1,068**	877
Conventional (Discontinued Operations)	**27**	159	**39**	304
Total Operating Margin	**938**	731	**1,107**	1,181





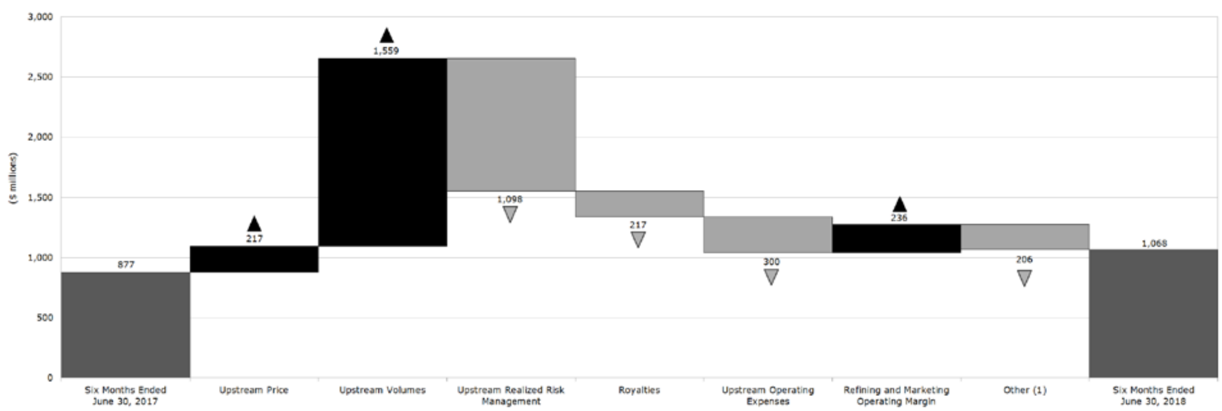
Operating Margin from continuing operations increased in 2018 compared with 2017 primarily due to:

- A rise in our liquids and natural gas sales volumes as a result of the Acquisition;
- An increase in our average liquids sales price, consistent with higher crude oil benchmark prices; and
- Higher Operating Margin from our Refining and Marketing segment due to wider crude oil differentials and higher average market crack spreads.

These increases in Operating Margin were partially offset by:

- A rise in transportation and blending expenses primarily due to an increase in condensate volumes required for blending our increased oil sands production and higher condensate prices;
- Upstream realized risk management losses of $698 million and $1,161 million in the three and six months ended June 30, 2018, respectively (2017 – $14 million gain and $63 million loss, respectively);
- An increase in upstream operating expenses primarily due to the Acquisition; and
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), higher sales volumes and increased realized sales prices.

Operating Margin From Continuing Operations Variance



(1) Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Additional details explaining the changes in Operating Margin from continuing operations can be found in the Reportable Segments section of this MD&A.

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

Total Cash From Operating Activities and Adjusted Funds Flow

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Cash From Operating Activities [(1)]	**533**	1,239	**410**	1,567
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(17)**	(25)	**(35)**	(56)
Net Change in Non-Cash Working Capital	**(224)**	519	**(288)**	555
Adjusted Funds Flow [(1)]	**774**	745	**733**	1,068

(1) *Includes results from our Conventional segment, which has been classified as a discontinued operation.*

Cash From Operating Activities was lower in the second quarter of 2018 compared with 2017. Although total Operating Margin was higher in the second quarter of 2018 than in 2017, Cash From Operating Activities in the second quarter of 2017 benefited from a $143 million realized risk management gain on foreign exchange contracts and a higher current tax recovery, partially offset by transaction costs of $26 million related to the Acquisition. The change in non-cash working capital in the second quarter of 2018 was primarily due to an increase in accounts receivable, partially offset by an increase in accounts payable and income tax payable. For the three months ended June 30, 2017, the change in non-cash working capital was primarily due to an increase in accounts receivable, partially offset by a rise in accounts payable.

Cash From Operating Activities and Adjusted Funds Flow were lower on a year-to-date basis compared with 2017. In 2018, our total Operating Margin and current tax recovery were lower, and we incurred higher general and administrative costs primarily due to $47 million of severance costs. The first half of 2017 benefited from realized risk management gains of $143 million on foreign exchange contracts, partially offset by transaction costs of $55 million related to the Acquisition. The change in non-cash working capital for the six months ended June 30, 2018 was primarily due to an increase in accounts receivable and a decline in income tax payable, partially offset by an increase in accounts payable. For the first six months of 2017, the change in non-cash working capital was primarily due to an increase in accounts receivable and a rise in inventory, partially offset by an increase in accounts payable

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, revaluation gain, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Earnings (Loss) From Continuing Operations, Before Income Tax	**(390)**	3,226	**(1,462)**	3,486
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [(1)]	**(122)**	(132)	**(261)**	(411)
Non-Operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**205**	(279)	**469**	(335)
Revaluation (Gain)	**-**	(2,555)	**-**	(2,555)
(Gain) Loss on Divestiture of Assets	**(1)**	-	**(1)**	1
Other	**1**	-	**-**	-
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**(307)**	260	**(1,255)**	186
Income Tax Expense (Recovery)	**(15)**	(38)	**(211)**	(73)
Operating Earnings (Loss) From Continuing Operations	**(292)**	298	**(1,044)**	259
Operating Earnings (Loss) From Discontinued Operations	**20**	54	**29**	54
Total Operating Earnings (Loss)	**(272)**	352	**(1,015)**	313

(1) *Includes the reversal of unrealized (gains) losses recorded in prior periods.*
(2) *Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.*

Operating Earnings from continuing operations decreased in the second quarter of 2018 compared with 2017 primarily due to lower cash from operating activities and Adjusted Funds Flow, as discussed above, a remeasurement loss of $377 million on the contingent payment compared with a gain of $66 million in 2017, an increase in DD&A, and unrealized foreign exchange losses of $3 million related to operating activities as compared with gains of $117 million in 2017.

For the six months ended June 30, 2018, Operating Earnings decreased relative to 2017 primarily due to lower cash from operating activities and Adjusted Funds Flow, as discussed above, a remeasurement loss of $494 million on the contingent payment compared with a gain of $66 million in 2017, an increase in DD&A that included an impairment of $100 million in 2018, and unrealized foreign exchange losses of $18 million on operating items compared with gains of $133 million in 2017.

Net Earnings (Loss)

($ millions)	Three Months Ended	Six Months Ended
Net Earnings (Loss) From Continuing Operations, for the Periods Ended June 30, 2017	**2,558**	**2,769**
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**339**	**191**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(10)**	**(150)**
Unrealized Foreign Exchange Gain (Loss)	**(609)**	**(963)**
Revaluation (Gain)	**(2,555)**	**(2,555)**
Re-measurement of Contingent Payment	**(443)**	**(560)**
Gain (Loss) on Divestiture of Assets	**1**	**2**
Expenses (1)	**(184)**	**(363)**
DD&A	**(151)**	**(544)**
Exploration Expense	**(4)**	**(6)**
Income Tax Recovery (Expense)	**648**	**855**
Net Earnings (Loss) From Continuing Operations, for the Periods Ended June 30, 2018	**(410)**	**(1,324)**

(1) *Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, transaction costs, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.*

Net earnings from continuing operations decreased in the second quarter of 2018 compared with 2017 due to:
- An after-tax revaluation gain of $1.9 billion on our pre-existing interest in FCCL recognized in 2017;
- Lower Operating Earnings, as discussed above; and
- Non-operating foreign exchange losses of $205 million compared with gains of $279 million in 2017.

On a year-to-date basis we incurred a net loss from continuing operations, a significant decrease from the first six months of 2017 due to:
- An after-tax revaluation gain of $1.9 billion on our pre-existing interest in FCCL recognized in 2017;
- Lower Operating Earnings, as discussed above;
- Non-operating foreign exchange losses of $469 million compared with gains of $335 million in 2017; and
- Unrealized risk management gains of $261 million compared with gains of $411 million in 2017.

For the three months ended June 30, 2018 we incurred a Net Loss from discontinued operations of $8 million (2017 – Net Earnings of $59 million). Net Earnings from discontinued operations for the six months ended June 30, 2018 was $252 million (2017 – $59 million), and includes an after-tax gain of $223 million on the divestiture of the Suffield assets in the first quarter of 2018.

Total Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Oil Sands	**224**	215	**542**	387
Deep Basin	**26**	13	**171**	13
Refining and Marketing	**35**	40	**88**	86
Corporate and Eliminations	**9**	9	**15**	16
Capital Investment - Continuing Operations	**294**	277	**816**	502
Conventional (Discontinued Operations)	**(2)**	50	**-**	138
Total Capital Investment (1)	**292**	327	**816**	640

(1) *Includes expenditures on PP&E, E&E assets and assets held for sale.*

Capital investment in continuing operations in 2018 increased compared with 2017, reflecting our increased ownership in FCCL and the new asset base in the Deep Basin as a result of the Acquisition. On a year-to-date basis, Oil Sands capital investment focused on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells; and the Christina Lake phase G expansion. Capital investment in the Deep Basin in the first half of the 2018 focused on all three operating areas and included the drilling of 15 net horizontal production wells targeting liquids rich natural gas, as well as capital invested in facilities and infrastructure to support production.

Refining and Marketing capital investment increased slightly for the six months ended June 30, 2018 due to increased capital maintenance and reliability work compared with the same period in 2017.

Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Capital Investment Decisions

We continue to focus on deleveraging our balance sheet. To achieve this, we are currently marketing for sale certain non-core Deep Basin Assets and are continuing to look for opportunities to further streamline our portfolio. In addition to our commitment to continue reducing our debt, we are actively identifying further cost reduction opportunities.

Once our balance sheet leverage is more in line with our target debt metric, our disciplined approach to capital allocation includes prioritizing our uses of cash in the following manner:

- First, to sustaining and maintenance capital for our existing business operations;
- Second, to paying our current dividend as part of providing strong total shareholder return; and
- Third, for incremental returns to shareholders and growth or discretionary capital.

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position us to be financially resilient in times of lower cash flows. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

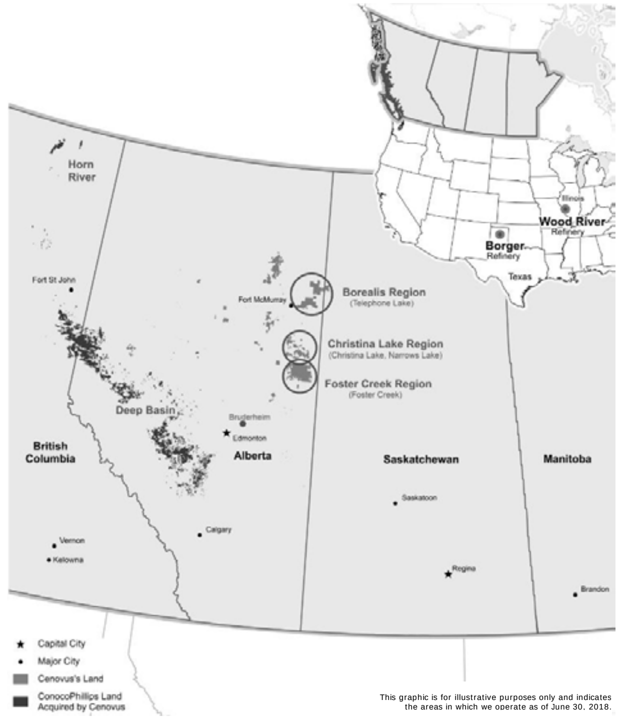
	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2018**	2017	**2018**	2017
Adjusted Funds Flow [1]	**774**	745	**733**	1,068
Total Capital Investment [1]	**292**	327	**816**	640
Free Funds Flow [1] [2]	**482**	418	**(83)**	428
Cash Dividends	**62**	61	**122**	102
	420	357	**(205)**	326

(1) Includes our Conventional segment, which has been classified as a discontinued operation.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We expect our capital investment and cash dividends for 2018 to be funded from our internally generated cash flows and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:



Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. Our interest in certain of our operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake increased from 50 percent to 100 percent on May 17, 2017.

Deep Basin, which includes approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and natural gas liquids. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. These assets were acquired on May 17, 2017.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

In the second quarter of 2017, Cenovus announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. As such, the associated results of operations have been reported as discontinued operations. As at January 5, 2018, all of the Conventional segment assets were sold. Refer to the Discontinued Operations section of this MD&A for more information.

Revenues by Reportable Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Oil Sands (1)	**3,069**	1,630	**5,417**	2,665
Deep Basin (2)	**225**	116	**449**	116
Refining and Marketing	**2,777**	2,397	**5,009**	5,001
Corporate and Eliminations	**(239)**	(106)	**(433)**	(204)
	5,832	4,037	**10,442**	7,578

(1) Our 2017 results include 45 days of FCCL operations at 100 percent. See the Oil Sands section of this MD&A for more details.
(2) Our 2017 results include 45 days of operations from the Deep Basin Assets. See the Deep Basin section of this MD&A for more details.

OIL SANDS

In northeastern Alberta, we own 100 percent of the Foster Creek, Christina Lake and Narrows Lake oil sands projects following the completion of the Acquisition. In addition, we have several emerging projects in the early stages of development. The Oil Sands segment includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Highlights in the second quarter of 2018 include:

- Increasing oil rates from producing wells at our Oil Sands facilities and recovering the majority of the volumes that were stored in the first quarter of 2018 following our decision to restrict crude oil volumes produced in response to takeaway capacity constraints and discounted heavy crude oil prices;
- Crude oil netbacks of $32.65 per barrel, excluding realized risk management activities, a 46 percent increase compared with the second quarter of 2017 due to a higher average realized sales price and a 20 percent reduction in per-barrel operating costs, partially offset by royalties increasing by $3.50 per barrel due primarily to an increase in the WTI benchmark price (which determines the royalty rate); and
- Operating Margin of $476 million, a five percent decrease compared with the second quarter of 2017 as increased sales volumes and higher average realized sales prices were offset by increased transportation and blending costs, realized risk management losses of $688 million compared with gains of $14 million in 2017, and increased royalties.

Oil Sands – Crude Oil

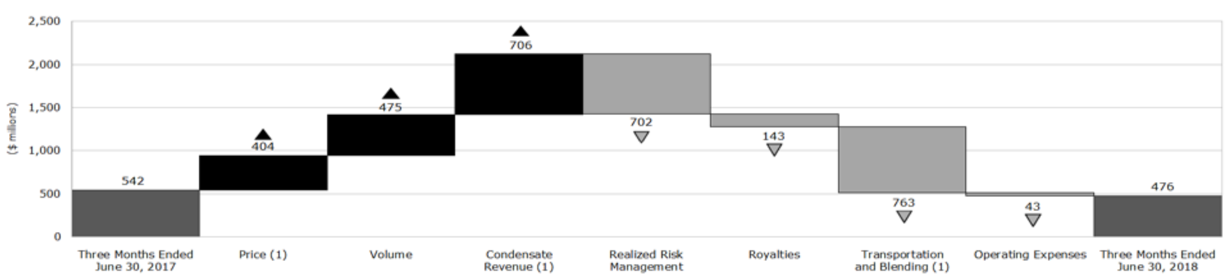
Three Months Ended June 30, 2018 Compared With June 30, 2017

Financial Results [1]

	Three Months Ended June 30,	
($ millions)	**2018**	2017
Gross Sales	**3,246**	1,661
Less: Royalties	**179**	36
Revenues	**3,067**	1,625
Expenses		
Transportation and Blending	**1,642**	879
Operating	**261**	218
(Gain) Loss on Risk Management	**688**	(14)
Operating Margin	**476**	542
Capital Investment	**224**	215
Operating Margin Net of Related Capital Investment	**252**	327

(1) Excludes results from the Athabasca natural gas property.

Operating Margin Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Price

In the second quarter of 2018, our average crude oil sales price increased to $51.07 per barrel (2017 – $39.73 per barrel). The increase in our crude oil price reflects the rise in WCS prices compared with the second quarter of 2017, partially offset by wider WCS-Condensate and WCS-Christina Dilbit Blend (“CDB”) differentials and the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential widened to a discount of US$2.95 per barrel (2017 – discount of US$1.53 per barrel).

Our crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate increases relative to the price of blended crude oil, our bitumen sales price decreases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising crude oil price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

	Three Months Ended June 30,		
(barrels per day)	**2018**	**Percent Change**	2017
Foster Creek	**171,079**	**59**	107,859
Christina Lake	**218,299**	**42**	153,953
	389,378	**49**	261,812

Oil Sands production averaged 389,378 barrels per day in the second quarter of 2018, a significant increase from the same period of 2017 primarily due to the Acquisition. Production in the second quarter also benefited from increased oil rates from producing wells following our decision to reduce production well rates in the first quarter of 2018 in order to leave producible barrels in our reservoirs due to takeaway capacity constraints and wider light-heavy crude oil price differentials. We used the significant storage capacity in our oil sands reservoirs to provide flexibility on timing of production, and were able to produce the majority of the barrels that were stored into a stronger crude oil price environment as pipeline apportionment was alleviated and crude oil price differentials narrowed. We remain on track to meet our 2018 oil sands production guidance. Production in the second quarter of 2017 was reduced by 11,073 barrels per day due to a major planned turnaround at Foster Creek.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with a wider WCS-Condensate differential in the second quarter of 2018, the proportion of the cost of condensate recovered decreased. The total amount of condensate used increased as a result of higher production volumes.

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre- and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalty calculations differ between properties.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

We anticipate that our Christina Lake project will reach payout for royalty purposes in the second half of 2018 once cumulative project revenue exceeds cumulative project allowable costs. After payout is achieved, the royalty rate at Christina Lake will follow the post-payout formula described above. Had Christina Lake been in a post-payout position in the second quarter of 2018, royalty rates would have been higher.

Effective Royalty Rates

	Three Months Ended June 30,	
(percent)	**2018**	2017
Foster Creek	**19.6**	7.3
Christina Lake	**4.2**	2.6

Royalties increased $143 million in the second quarter of 2018 compared with 2017. Royalties at both Foster Creek and Christina Lake increased primarily due to a higher WTI benchmark price (which determines the royalty rate), higher realized crude oil sales prices, and increased sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs increased $763 million compared to the second quarter of 2017. Blending costs increased due to a rise in condensate volumes required for our increased production and higher condensate prices, driven by higher light oil benchmark prices. Our condensate costs were higher than the average Edmonton benchmark price, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects. Transportation costs increased primarily due to incremental sales volumes as a result of the Acquisition.

Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs declined $2.90 per barrel due to a higher proportion of Canadian sales resulting in lower costs associated with pipeline tariffs. Christina Lake transportation costs increased $0.85 per barrel as a result of increased U.S. sales relative to the second quarter of 2017.

Operating

Primary drivers of our operating expenses in the second quarter of 2018 were workforce costs, fuel, chemical costs, repairs and maintenance and workovers. While total operating expenses increased $43 million primarily due to the Acquisition, per-barrel operating costs decreased 20 percent.

Per-unit Operating Expenses

	Three Months Ended June 30,		
($/bbl)	**2018**	**Percent Change**	2017
Foster Creek			
Fuel	**1.91**	**(34)**	2.89
Non-fuel	**6.84**	**(27)**	9.42
Total	**8.75**	**(29)**	12.31
Christina Lake			
Fuel	**1.77**	**(26)**	2.38
Non-fuel	**4.45**	**(5)**	4.66
Total	**6.22**	**(12)**	7.04
Total	**7.32**	**(20)**	9.19

At both Foster Creek and Christina Lake, per-barrel fuel costs decreased in the second quarter of 2018 due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses decreased primarily due to higher sales volumes, a reduction in workforce costs, and lower repairs and maintenance, partially offset by higher chemical costs.

Netbacks [1]

	Foster Creek		Christina Lake	
	Three Months Ended June 30,			
($/bbl)	**2018**	2017	**2018**	2017
Sales Price	**54.08**	44.38	**48.74**	36.54
Royalties	**9.14**	2.49	**1.84**	0.85
Transportation and Blending	**7.54**	10.44	**4.95**	4.10
Operating Expenses	**8.75**	12.31	**6.22**	7.04
Netback Excluding Realized Risk Management	**28.65**	19.14	**35.73**	24.55
Realized Risk Management Gain (Loss)	**(19.54)**	1.01	**(19.08)**	0.34
Netback Including Realized Risk Management	**9.11**	20.15	**16.65**	24.89

(1) Netbacks reflect our operating margin on a per-barrel basis of unblended crude oil.

Risk Management

Risk management positions in the second quarter of 2018 resulted in realized losses of $688 million (2017 – realized gains of $14 million), consistent with average benchmark prices exceeding our contract prices on hedging contracts that were established to provide downside protection and support financial resilience following the Acquisition.

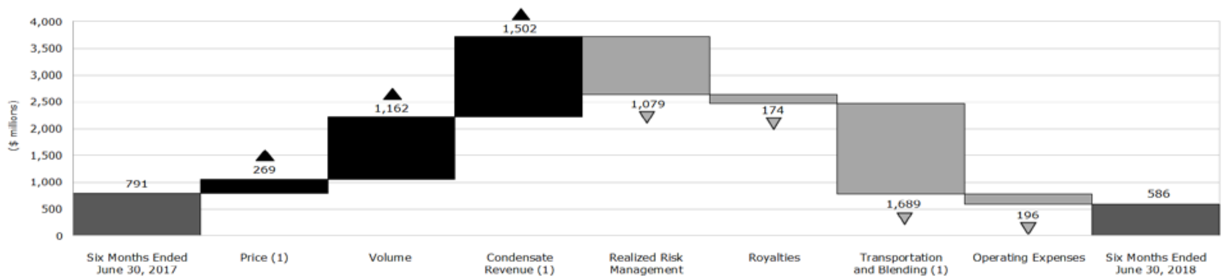
Six Months Ended June 30, 2018 Compared With June 30, 2017

Financial Results [1]

($ millions)	Six Months Ended June 30, 2018	2017
Gross Sales	**5,649**	2,716
Less: Royalties	**237**	63
Revenues	**5,412**	2,653
Expenses		
Transportation and Blending	**3,134**	1,445
Operating	**550**	354
(Gain) Loss on Risk Management	**1,142**	63
Operating Margin	**586**	791
Capital Investment	**541**	384
Operating Margin Net of Related Capital Investment	**45**	407

(1) Excludes results from the Athabasca natural gas property.

Operating Margin Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Price

In the six months ended June 30, 2018, our average crude oil sales price increased to $43.00 per barrel (2017 – $39.09 per barrel). The increase in our crude oil price reflects the rise in WCS prices compared with the first six months of 2017, partially offset by wider WCS-Condensate and WCS-CDB differentials and the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential widened to a discount of US$2.81 per barrel (2017 – discount of US$1.66 per barrel).

Production Volumes

(barrels per day)	Six Months Ended June 30, 2018	Percent Change	2017
Foster Creek	**164,273**	**74**	94,437
Christina Lake	**210,332**	**65**	127,442
	374,605	**69**	221,879

Production at both Foster Creek and Christina Lake was higher compared to 2017 primarily due to the Acquisition. Oil Sands production was also impacted by our decision to reduce producing well rates in the first quarter of 2018, due to takeaway capacity constraints and discounted heavy crude oil pricing, and by the subsequent ramp-up of production in the second quarter as light-heavy oil price differentials narrowed. Production in the first half of 2017 was reduced by 5,567 barrels per day due to a major planned turnaround at Foster Creek in the second quarter.

Royalties

Effective Royalty Rates

(percent)	Six Months Ended June 30, 2018	2017
Foster Creek	**16.1**	7.8
Christina Lake	**3.5**	2.6

On a year-to-date basis, royalties increased $174 million compared with 2017. Royalties at both Foster Creek and Christina Lake increased primarily due to a higher WTI benchmark price (which determines the royalty rate), increased sales volumes and higher crude oil sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $1,689 million. Blending costs increased due to a rise in condensate volumes required for our increased production and higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects. Transportation costs increased primarily due to incremental sales volumes as a result of the Acquisition.

Per-unit Transportation Expenses

Foster Creek per-barrel transportation costs declined $1.07 per barrel due to a higher proportion of Canadian sales resulting in lower costs associated with pipeline tariffs. Christina Lake transportation costs increased $0.76 per barrel as a result of increased U.S. sales relative to the second quarter of 2017.

Operating

Primary drivers of our operating expenses in the first half of 2018 were workforce costs, fuel, chemical costs, repairs and maintenance and workovers. While total operating costs increased $196 million primarily due to the Acquisition, per-barrel operating expenses decreased 12 percent.

Per-unit Operating Expenses

	Six Months Ended June 30,		
($/bbl)	**2018**	**Percent Change**	2017
Foster Creek			
Fuel	**2.32**	**(20)**	2.91
Non-fuel	**7.29**	**(13)**	8.42
Total	**9.61**	**(15)**	11.33
Christina Lake			
Fuel	**2.04**	**(17)**	2.45
Non-fuel	**4.73**	**(5)**	4.97
Total	**6.77**	**(9)**	7.42
Total	**8.02**	**(12)**	9.10

At both Foster Creek and Christina Lake, per-barrel fuel costs decreased due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses decreased in the first half of 2018 primarily due to higher sales volumes, lower workforce costs, and a decrease in repairs and maintenance, partially offset by increased chemical costs.

Netbacks (1)

	Foster Creek		Christina Lake	
	Six Months Ended June 30,			
($/bbl)	**2018**	2017	**2018**	2017
Sales Price	**46.89**	42.79	**39.93**	36.29
Royalties	**6.23**	2.64	**1.25**	0.85
Transportation and Blending	**8.22**	9.29	**4.87**	4.11
Operating Expenses	**9.61**	11.33	**6.77**	7.42
Netback Excluding Realized Risk Management	**22.83**	19.53	**27.04**	23.91
Realized Risk Management Gain (Loss)	**(16.62)**	(1.84)	**(16.66)**	(1.44)
Netback Including Realized Risk Management	**6.21**	17.69	**10.38**	22.47

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Risk Management

Risk management positions in the first six months of 2018 resulted in realized losses of $1,142 million (2017 – realized losses of $63 million), consistent with average benchmark prices exceeding our contract prices on hedging contracts that were established to provide downside protection and support financial resilience following the Acquisition.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production in the three and six months ended June 30, 2018, net of internal usage, was 1 MMcf per day and 2 MMcf per day, respectively (2017 – 12 MMcf per day and 13 MMcf per day, respectively).

Operating Margin from our Oil Sands natural gas production was $nil in the second quarter (2017 – $2 million) and negative $1 million on a year-to-date basis (2017 – $3 million), decreasing primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Foster Creek	**108**	120	**247**	190
Christina Lake	**111**	77	**275**	140
	219	197	**522**	330
Other [1]	**5**	18	**20**	57
Capital Investment [2]	**224**	215	**542**	387

(1) Includes new resource plays, Narrows Lake, Telephone Lake and Athabasca natural gas.
(2) Includes expenditures on PP&E, and E&E assets.

Capital investment in the first half of 2018 increased by $155 million from 2017, reflecting our 100 percent ownership of FCCL as of May 17, 2017. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells.

In the first six months of 2018 and 2017, Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells and the phase G expansion.

Drilling Activity

Six Months Ended June 30,	Gross Stratigraphic Test Wells 2018	2017	Gross Production Wells [1] 2018	2017
Foster Creek	**43**	93	**14**	20
Christina Lake	**63**	98	**18**	8
	106	191	**32**	28
Other	**20**	16	**-**	-
	126	207	**32**	28

(1) SAGD well pairs are counted as a single producing well.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and near-term expansion phases and to further progress the evaluation of emerging assets.

Future Capital Investment

Foster Creek is currently producing from phases A through G. Capital investment for 2018 is forecast to be between $500 million and $550 million. We plan to continue focusing on sustaining capital related to existing production.

Christina Lake is producing from phases A through F. Capital investment for 2018 is forecast to be between $500 million and $550 million, focused on sustaining capital and construction of the phase G expansion. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, is progressing well and remains on track. Phase G is expected to start producing in the second half of 2019.

Capital investment at Narrows Lake in 2018 is forecast to be between $5 million and $10 million and will focus primarily on equipment and site preservation related to the suspension of construction at Narrows Lake.

In 2018, our Technology and other capital investment, forecast to be between $35 million and $45 million, relates to technology development initiatives and annual environmental and regulatory commitments.

Our 2018 Oil Sands total capital investment is forecast to be between $1,040 million and $1,155 million. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

The following calculation illustrates how the implied depletion rate for our total upstream assets could be determined using the reported consolidated data:

($ millions, unless otherwise indicated)	As at December 31, 2017
Upstream Property, Plant and Equipment	26,341
Estimated Future Development Capital	30,195
Total Estimated Upstream Cost Base	56,536
Total Proved Reserves (MMBOE)	5,232
Implied Depletion Rate ($/BOE)	10.81

While this illustrates the calculation of the implied depletion rate, our depletion rates resulted in a total average rate ranging between $8.75 to $11.30 per BOE. Amounts related to assets under construction and assets held for sale, which would be included in the total upstream cost base noted above and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the December 31, 2017 Consolidated Financial Statements.

Future development costs declined due to an increase in well pair lengths at Christina Lake, resulting in a reduction in the number of pads and well pairs required, as well as cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs and increased well pair spacing. This decline was partially offset by an increase in the future development costs at Foster Creek as a result of a development area expansion.

In the three and six months ended June 30, 2018, Oil Sands DD&A increased by $99 million and $291 million, respectively, compared with 2017, as a result of increased production volumes. The average DD&A rate in the first six months of 2018 was approximately $10.61 per barrel (2017 – $10.99 per barrel).

There was exploration expense of $4 million and $6 million, recorded in the three and six months ended June 30, 2018, respectively (2017 – $nil).

DEEP BASIN

Our Deep Basin Assets include liquids rich natural gas, condensate and other NGLs, as well as light and medium oil located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities. The Deep Basin Assets provide short-cycle development opportunities with high-return potential that complement our long-term oil sands development. In addition, a portion of the natural gas produced is used as fuel in our oil sands operations and provides an economic hedge for the natural gas required as a fuel source at the Refineries.

Highlights in the second quarter of 2018 include:

- Total production of 129,066 BOE per day;
- Total capital investment of $26 million related to facilities and infrastructure to support production, as well as drilling one net horizontal production well, completing one net well and bringing three net wells on production;
- Netback of $6.94 per BOE, before realized hedging; and
- Generating Operating Margin of $78 million.

Financial Results

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Gross Sales	**241**	124	**500**	124
Less: Royalties	**16**	8	**51**	8
Revenues	**225**	116	**449**	116
Expenses				-
Transportation and Blending	**27**	10	**52**	10
Operating	**109**	55	**200**	55
Production and Mineral Taxes	**1**	-	**1**	-
(Gain) Loss on Risk Management	**10**	-	**19**	-
Operating Margin	**78**	51	**177**	51
Capital Investment	**26**	13	**171**	13
Operating Margin Net of Related Capital Investment	**52**	38	**6**	38

Revenues

Price

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Light and Medium Oil ($/bbl)	**79.96**	62.29	**73.54**	62.29
NGLs ($/bbl)	**42.30**	27.22	**39.98**	27.22
Natural Gas ($/mcf)	**1.34**	2.88	**1.77**	2.88
Total Oil Equivalent ($/BOE)	**18.92**	21.94	**20.28**	21.94

For the three and six months ended June 30, 2018, revenues included $18 million and $30 million, respectively, of processing fee revenue related to our interests in natural gas processing facilities. We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Liquids				
Crude Oil (barrels per day)	**6,263**	3,059	**6,389**	1,538
NGLs (barrels per day)	**27,778**	13,835	**28,367**	6,956
	34,041	16,894	**34,756**	8,494
Natural Gas (MMcf per day)	**570**	253	**560**	127
Total Production (BOE/d)	**129,066**	58,981	**128,067**	29,654
Natural Gas Production (percentage of total)	**74**	71	**73**	71
Liquids Production (percentage of total)	**26**	29	**27**	29

Royalties

The Deep Basin Assets are subject to royalty regimes in both Alberta and British Columbia. In Alberta, royalties benefit from a number of different programs that reduce the royalty rate on natural gas production. Natural gas wells in Alberta also benefit from the Gas Cost Allowance ("GCA"), which reduces royalties, to account for capital and operating costs incurred to process and transport the Crown's portion of natural gas production.

Effective January 1, 2017, the Alberta Government released a new Royalty Regime, Alberta's Modernized Royalty Framework ("MRF"), which applies to all producing wells after January 1, 2017. Under this new framework, Cenovus will pay a five percent pre-payout royalty on all production until the total revenue from a well equals the drilling and completion cost allowance calculated for each well that meets certain MRF criteria. Subsequently, a higher post-payout royalty rate will apply and will vary based on product-specific market prices. Once a well reaches a maturity threshold, the royalty rate will drop to better match declining production rates. Wells drilled before January 1, 2017 will be managed under the old framework until 2027 and then will convert to the MRF.

In British Columbia, royalties also benefit from programs to reduce the rate on natural gas production. British Columbia applies a GCA, but only on natural gas processed through producer-owned plants. British Columbia also offers a Producer Cost of Service allowance, which reduces the royalty for the processing of the Crown's portion of natural gas production.

For the three and six months ended June 30, 2018, our effective liquids royalty rate was 10.6 percent and 16.5 percent, respectively (2017 – 11.7 percent). In the second quarter and on a year-to-date basis in 2018, the effective natural gas royalty rate was 1.0 percent and 4.1 percent, respectively (2017 – 4.1 percent).

Expenses

Transportation

Transportation costs averaged $1.92 per BOE and $2.06 per BOE for the three and six months ended June 30, 2018, respectively (2017 – $1.96 per BOE). Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. The majority of Deep Basin production is sold into the Alberta market.

Operating

Primary drivers of our operating expenses were related to workforce, repairs and maintenance, processing fee expenses, and property tax and lease costs. We continued to focus on optimization of maintenance processes in the first half of 2018, resulting in increased runtimes and lower repairs and maintenance costs. In addition, operating costs decreased from 2017 due to a reduction in workforce costs. Operating costs averaged $8.68 and $8.03 per BOE in the three and six months ended June 30, 2018, respectively, compared with $8.84 per BOE for the same periods in 2017.

Netbacks

	Three Months Ended June 30,		Six Months Ended June 30,	
($/BOE)	**2018**	2017	**2018**	2017
Sales Price	**18.92**	21.94	**20.28**	21.94
Royalties	**1.34**	1.45	**2.20**	1.45
Transportation and Blending	**1.92**	1.96	**2.06**	1.96
Operating Expenses	**8.68**	8.84	**8.03**	8.84
Production and Mineral Taxes	**0.04**	0.03	**0.03**	0.03
Netback Excluding Realized Risk Management	**6.94**	9.66	**7.96**	9.66
Realized Risk Management Gain (Loss)	**(0.85)**	-	**(0.82)**	-
Netback Including Realized Risk Management	**6.09**	9.66	**7.14**	9.66

Risk Management

Risk management activities in the three and six months ended June 30, 2018 resulted in realized losses of $10 million and $19 million, respectively (2017 – $nil).

Deep Basin – Capital Investment

For the three and six months ended June 30, 2018, capital investment was focused on developing all three operating areas. We completed the majority of our 2018 drilling program in the first quarter and in the second quarter we participated in the drilling of one additional net well, completed one net well, and brought three net wells on production. On a year-to-date basis, we participated in the drilling of 15 net horizontal wells targeting liquids rich natural gas, completed 17 net wells, and brought 20 net wells on production. In the three and six months ended June 30, 2018, Cenovus invested $10 million and $45 million, respectively, on facilities and infrastructure to support production in our core development areas.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Drilling and Completions	**10**	5	**104**	5
Facilities	**10**	2	**45**	2
Other	**6**	6	**22**	6
Capital Investment (1)	**26**	13	**171**	13

(1) Includes expenditures on PP&E, E&E assets and assets held for sale.

Drilling Activity

The following table summarizes Cenovus's net well activity for the three and six months ended June 30, 2018:

	Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
	Drilled [(1)]	**Completed**	**Tied-in**	**Drilled [(2)]**	**Completed**	**Tied-in**
Elmworth-Wapiti	-	-	-	4	6	9
Kaybob-Edson	1	1	-	8	9	4
Clearwater	-	-	3	3	2	7
Total	**1**	**1**	**3**	**15**	**17**	**20**

(1) Reflects one non-operated net horizontal well for the three months ended June 30, 2018.
(2) Includes 13 operated net horizontal wells and two non-operated net horizontal wells for the six months ended June 30, 2018.

Future Capital Investment

Our 2018 Deep Basin capital investment is forecast to be between $175 million and $195 million.

We continue to take a disciplined approach to the development of our Deep Basin assets. We plan to focus capital investment on drilling, completion and tie-in opportunities that have the potential to generate strong returns and increase throughput at underutilized facilities. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $10.35 per BOE for the three and six months ended June 30, 2018 (2017 – $10.49 per barrel).

For the three and six months ended June 30, 2018 total Deep Basin DD&A was $107 million and $311 million, respectively. On a year-to-date basis, DD&A included an impairment loss of $100 million recorded in the first quarter associated with our Clearwater cash-generating unit ("CGU").

Assets and Liabilities Held for Sale

In the fourth quarter of 2017, we commenced marketing for sale certain non-core assets located primarily in the East Clearwater area. The properties currently produce approximately 15,000 BOE per day of natural gas and NGLs. These assets were reclassified as assets held for sale and are recorded at the lesser of their carrying amount and fair value less costs to sell.

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. and operated by our partner, Phillips 66. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta.

Highlights in the second quarter of 2018 include:

- Achieving record monthly crude oil runs at both the Wood River and Borger refineries during the quarter following the completion of major planned turnarounds that began in the first quarter of 2018;
- Benefiting from significantly wider WTI-WCS and WTI-WTS crude oil differentials compared with the second quarter of 2017, creating a feedstock cost advantage at both refineries; and
- Generating Operating Margin of $357 million compared with $20 million in the second quarter of 2017.

Refinery Operations [(1)]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	**2018**	2017
Crude Oil Capacity (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**464**	449	**407**	428
Heavy Crude Oil	**203**	201	**183**	201
Light/Medium	**261**	248	**224**	227
Refined Products (Mbbls/d)	**490**	476	**430**	455
Gasoline	**233**	225	**211**	226
Distillate	**158**	154	**139**	143
Other	**99**	97	**80**	86
Crude Utilization (percent)	**101**	98	**88**	93

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

On a 100 percent basis, the Refineries have a total processing capacity of approximately 460,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil and 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output increased for the three months ended June 30, 2018 compared with the second quarter of 2017, with both refineries achieving record monthly crude oil runs during the second quarter of 2018. On a year-to-date basis, crude oil runs and refined product output decreased compared with 2017 due to the major planned turnarounds and maintenance at both refineries in the first quarter of 2018. In addition, lower heavy crude oil volumes were processed resulting from optimization of the total crude input slate.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Revenues	**2,777**	2,397	**5,009**	5,001
Purchased Product	**2,224**	2,183	**4,181**	4,513
Gross Margin	**553**	214	**828**	488
Expenses				
Operating	**197**	192	**515**	411
(Gain) Loss on Risk Management	**(1)**	2	**4**	4
Operating Margin	**357**	20	**309**	73
Capital Investment	**35**	40	**88**	86
Operating Margin Net of Related Capital Investment	**322**	(20)	**221**	(13)

Gross Margin

The refining realized crack spread, which is the gross margin on a per barrel basis, is affected by many factors, such as the variety of feedstock crude oil processed; refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the Refineries; and the cost of feedstock. Feedstock costs are valued on a FIFO accounting basis.

In the three and six months ended June 30, 2018, Refining and Marketing gross margin increased primarily due to wider crude oil differentials, creating a feedstock cost advantage, and higher refined product prices. These increases were partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact on our gross margin of approximately $23 million and $35 million for the three and six months ended June 30, 2018, respectively.

In the three and six months ended June 30, 2018, the cost of Renewable Identification Numbers ("RINs") was $34 million and $81 million, respectively (2017 – $66 million and $127 million, respectively). The cost of RINs declined due to the decrease in RINs benchmark prices and lower volume obligations due to the turnarounds.

Operating Expense

Primary drivers of operating expenses in the second quarter of 2018 were labour, maintenance, and utilities. Operating expenses decreased in the second quarter of 2018 primarily due to a reduction in planned maintenance and turnaround costs and the strengthening of the Canadian dollar relative to the U.S. dollar.

For the six months ended June 30, 2018, the primary drivers of operating expenses were maintenance, labour and utilities. Operating expenses increased on a year-to-date basis primarily due to higher planned maintenance and turnaround costs in the first six months of the year relative to the same period in 2017.

Refining and Marketing – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Wood River Refinery	**23**	22	**58**	56
Borger Refinery	**11**	17	**28**	29
Marketing	**1**	1	**2**	1
	35	40	**88**	86

Capital expenditures in the first half of 2018 focused primarily on capital maintenance and reliability work. Capital investment decreased in the second quarter of 2018, and increased slightly for the six months ended June 30, 2018 compared with the prior year.

In 2018, we expect to invest between $180 million and $210 million mainly related to capital maintenance and reliability work. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. For the three and six months ended June 30, 2018, Refining and Marketing DD&A was $55 million and $109 million, respectively (2017 – $55 million and $109 million, respectively).

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory including natural gas and crude oil sales and purchases. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains and losses, if any, on interest rate swaps and foreign exchange contracts. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, finance costs, interest income, foreign exchange (gain) loss, revaluation (gain), transaction costs, re-measurement of the contingent payment, research costs, (gain) loss on divestiture of assets, and other (income) loss.

In the three and six months ended June 30, 2018, our risk management activities resulted in:

- Unrealized risk management gains of $122 million (2017 – $132 million) and $261 million (2017 – $411 million), respectively; and
- Realized risk management gains on foreign exchange contracts of $nil (2017 – gains of $143 million) and a loss of $1 million (2017 – gains of $143 million), respectively. Risk management gains in 2017 related to hedging activity undertaken to support the Acquisition.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
General and Administrative	**109**	58	**288**	101
Finance Costs	**156**	168	**306**	267
Interest Income	**(3)**	(10)	**(6)**	(27)
Foreign Exchange (Gain) Loss, Net	**212**	(410)	**489**	(486)
Revaluation (Gain)	**-**	(2,555)	**-**	(2,555)
Transaction Costs	**-**	26	**-**	55
Re-measurement of Contingent Payment	**377**	(66)	**494**	(66)
Research Costs	**7**	5	**19**	9
(Gain) Loss on Divestiture of Assets	**(1)**	-	**(1)**	1
Other (Income) Loss, Net	**2**	(2)	**-**	(2)
	859	(2,786)	**1,589**	(2,703)

Expenses

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs and office rent. General and administrative expenses increased by $51 million in the second quarter of 2018 compared with 2017 due to higher long-term employee incentive costs related to a rise in our share price, and an increase in our rent costs. On a year-to-date basis, general and administrative expenses increased primarily due to higher rent costs, including a non-cash expense of $62 million recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and costs associated with office space at Brookfield Place, for which Cenovus signed a long-term lease in 2013. In addition, $47 million in severance costs related to workforce reductions carried out in the first six months of 2018 were recorded.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs decreased by $12 million in the three months ended June 30, 2018 compared with 2017 due to lower interest on short-term borrowings. In the second quarter of 2017, we borrowed $3.6 billion under a committed Bridge Facility and U.S.$2.9 billion of senior unsecured notes in connection with the Acquisition. On a year-to-date basis, finance costs increased by $39 million compared with 2017, reflecting six months of costs associated with the US$2.9 billion of senior unsecured notes in 2018 compared with only three months in 2017. The full amount of the committed Bridge Facility was repaid prior to December 31, 2017.

The weighted average interest rate on outstanding debt for the three and six months ended June 30, 2018 was 5.1 percent (2017 – 4.8 percent and 5.0 percent, respectively).

Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Unrealized Foreign Exchange (Gain) Loss	**213**	(396)	**495**	(468)
Realized Foreign Exchange (Gain) Loss	**(1)**	(14)	**(6)**	(18)
	212	(410)	**489**	(486)

In 2018, unrealized foreign exchange losses were recorded primarily as a result of the translation of our U.S. dollar denominated debt. At June 30, 2018, the Canadian dollar relative to the U.S. dollar was two percent weaker compared with March 31, 2018 and five percent weaker compared with December 31, 2017, creating unrealized losses.

Revaluation (Gain)

Prior to the Acquisition, our 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, *"Joint Arrangements"* and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, we control FCCL, as defined under IFRS 10, *"Consolidated Financial Statements"* and accordingly, FCCL has been consolidated. As required by IFRS 3 when control is achieved in stages, the previously held interest in FCCL was re-measured to its fair value of $12.3 billion and a non-cash revaluation gain of $2.6 billion ($1.9 billion, after-tax) was recorded in our 2017 net earnings.

Transaction Costs

In the first six months of 2017, we expensed $55 million of transaction costs related to the Acquisition.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date of the Acquisition for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $635 million as at June 30, 2018 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the three and six months ended June 30, 2018 a non-cash re-measurement loss of $377 million and $494 million, respectively, was recorded. As at June 30, 2018, $65 million is payable under this agreement.

Average WCS forward pricing for the remaining term of the contingent payment is US$39.83 or C$52.45 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$44.10 per barrel and C$64.00 per barrel.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in the second quarter of 2018 was $14 million (2017 – $14 million) and $29 million on a year-to-date basis (2017 – $32 million).

Income Tax

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2018**	2017	**2018**	2017
Current Tax				
Canada	**(35)**	(183)	**(93)**	(209)
United States	**-**	-	**4**	(1)
Current Tax Expense (Recovery)	**(35)**	(183)	**(89)**	(210)
Deferred Tax Expense (Recovery)	**55**	851	**(49)**	927
Total Tax Expense (Recovery) From Continuing Operations	**20**	668	**(138)**	717

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and as a result, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

In the three and six months ended June 30, 2018 and 2017, a current tax recovery from continuing operations was recorded due to the carryback of current and prior year losses.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences. Our effective tax rate differs from the statutory tax rate due to non-recognition of the potential tax benefit relating to foreign exchange losses.

DISCONTINUED OPERATIONS

In 2017, Cenovus divested the majority of its Conventional segment which included its heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. The associated assets and liabilities were reclassified as held for sale and the results of operations reported as a discontinued operation.

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. A before-tax gain on discontinuance of $306 million was recorded on the sale. Our results in the second quarter of 2018 reflect customary post-closing adjustments.

Financial Results

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Gross Sales	**(1)**	386	**15**	760
Less: Royalties	**2**	50	**1**	100
Revenues	**(3)**	336	**14**	660
Expenses				
Transportation and Blending	**-**	54	**1**	105
Operating	**(32)**	115	**(27)**	225
Production and Mineral Taxes	**2**	5	**1**	10
(Gain) Loss on Risk Management	**-**	3	**-**	16
Operating Margin	**27**	159	**39**	304
Depreciation, Depletion and Amortization	**-**	69	**-**	190
Exploration Expense	**-**	(1)	**-**	2
Finance Costs	**-**	12	**-**	33
Earnings (Loss) From Discontinued Operations Before Income Tax	**27**	79	**39**	79
Current Tax Expense (Recovery)	**-**	17	**-**	22
Deferred Tax Expense (Recovery)	**7**	3	**10**	(2)
After-tax Earnings (Loss) From Discontinued Operations	**20**	59	**29**	59
After-tax Gain (Loss) on Discontinuance [1]	**(28)**	-	**223**	-
Net Earnings (Loss) From Discontinued Operations	**(8)**	59	**252**	59

(1) Net of deferred tax recovery of $10 million in the three months ended June 30, 2018 and net of deferred tax expense of $83 million in the six months ended June 30, 2018.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2018	2017	Six Months Ended June 30, 2018	2017
Cash From (Used In)				
Operating Activities – Continuing Operations	**506**	1,102	**372**	1,297
Operating Activities – Discontinued Operations	**27**	137	**38**	270
Total Operating Activities	**533**	1,239	**410**	1,567
Investing Activities – Continuing Operations	**(464)**	(14,656)	**(954)**	(15,027)
Investing Activities – Discontinued Operations	**(37)**	(50)	**414**	(138)
Total Investing Activities	**(501)**	(14,706)	**(540)**	(15,165)
Net Cash Provided (Used) Before Financing Activities	**32**	(13,467)	**(130)**	(13,598)
Financing Activities	**(77)**	10,288	**(136)**	10,236
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**16**	120	**32**	131
Increase (Decrease) in Cash and Cash Equivalents	**(29)**	(3,059)	**(234)**	(3,231)

	June 30, 2018	December 31, 2017
Cash and Cash Equivalents	**376**	610
Committed and Undrawn Credit Facility	**4,500**	4,500

Cash From (Used In) Operating Activities

In the three months ended June 30, 2018, cash from operating activities decreased mainly due to the settlement timing of our non-cash working capital balances, and the impact of a realized risk management gain on foreign exchange contracts that was recognized in 2017 due to hedging activity undertaken to support the Acquisition, while partially offset by higher Operating Margin, as discussed in the Financial Results section of this MD&A.

In the six months ended June 30, 2018, cash from operating activities declined mainly as a result of the settlement timing of our non-cash working capital balances, an increase in general and administrative costs primarily due to severance costs of $47 million and higher rent costs, the impact of a realized risk management gain on foreign exchange contracts in 2017, as discussed above, and lower Operating Margin, as discussed in the Financial Results section of this MD&A.

In the three and six months ended June 30, 2018, cash from operating activities related to discontinued operations was $27 million and $38 million, respectively (2017 – $137 million and $270 million, respectively).

Excluding risk management assets and liabilities, assets and liabilities held for sale, and the current portion of the contingent payment, our working capital was $1,315 million at June 30, 2018 compared with $1,133 million at December 31, 2017.

We anticipate that we will continue to meet our payment obligations as they come due.

Cash From (Used In) Investing Activities

Cash used in investing activities in the three and six months ended June 30, 2018 was lower than in 2017 due to the cash used to fund the Acquisition, partially offset by higher capital investment in the first half of 2018. Additionally, on a year-to-date basis, proceeds from the divestiture of our Suffield asset in 2018 also contributed to the decrease.

Cash From (Used In) Financing Activities

Cash from financing activities was lower in 2018 compared with 2017 primarily due to the issuance of debt and common shares in 2017 to help finance the Acquisition.

Total debt as at June 30, 2018 was $9,992 million (December 31, 2017 – $9,513 million), with no principal payments due until October 15, 2019 (US$1,300 million). The principal amount of long-term debt outstanding in U.S. dollars remained unchanged since December 31, 2017 (US$7,650 million), with the increase in total debt due to the weakening of the Canadian dollar relative to the U.S. dollar.

As at June 30, 2018, we were in compliance with all of the terms of our debt agreements.

Dividends

In the three and six months ended June 30, 2018, we paid dividends of $0.05 per share or $62 million and $0.10 per share or $122 million, respectively (2017 – $0.05 per share or $61 million and $0.10 per share or $102 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

We expect cash flows from our upstream and refining operations to fund all of our cash requirements in 2018. Any potential shortfalls may be funded through prudent use of our balance sheet capacity including draws on our credit facility, management of our asset portfolio and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, DBRS Limited and Fitch Ratings.

The following sources of liquidity are available at June 30, 2018:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**376**
Committed Credit Facility – Tranche A	**November 2021**	**3,300**
Committed Credit Facility – Tranche B	**November 2020**	**1,200**

Committed Credit Facility

We have a committed credit facility in place that consists of a $1.2 billion tranche maturing on November 30, 2020 and $3.3 billion tranche maturing on November 30, 2021. As of June 30, 2018, no amounts were drawn on our committed credit facility.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in November 2019. As at June 30, 2018, US$4.6 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing 12-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at	June 30, 2018	December 31, 2017
Net Debt to Capitalization (percent)	**34**	31
Net Debt to Adjusted EBITDA	**3.3x**	2.8x

Over the long term, Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on our credit facility or repay existing debt, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new debt, or issue new shares.

Additional information regarding our financial measures and capital structure can be found in the notes to the interim Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at June 30, 2018, there were approximately 1,229 million common shares outstanding (December 31, 2017 – 1,229 million common shares). In the second quarter of 2017, Cenovus closed a bought-deal common share financing for 187.5 million common shares, raising gross proceeds of $3.0 billion ($2.9 billion net of $101 million of share issuance costs).

In addition, Cenovus issued 208 million common shares to ConocoPhillips on May 17, 2017 as partial consideration for the Acquisition. In relation to the share consideration, Cenovus and ConocoPhillips entered into an investor agreement, and a registration rights agreement which, among other things, restricted ConocoPhillips from selling or hedging its Cenovus common shares until after November 17, 2017. ConocoPhillips is also restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the then outstanding common shares of Cenovus. As at June 30, 2018, ConocoPhillips continued to hold these common shares.

Refer to Note 20 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our Performance Share Unit, Restricted Share Unit and Deferred Share Unit Plans.

As at June 30, 2018	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**36,864**	**29,247**
Other Stock-Based Compensation Plans	**14,872**	**1,538**

Contractual Obligations and Commitments

Cenovus has obligations for goods and services that were entered into in the normal course of business. Obligations are primarily related to transportation agreements, operating leases on buildings, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the December 31, 2017 Consolidated Financial Statements.

As at June 30, 2018, total commitments were $21 billion, of which $18 billion were for various transportation commitments. Transportation commitments include $9 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2017 – $9 billion). These agreements are for terms up to 20 years subsequent to the date of commencement.

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil.

As at June 30, 2018, there were outstanding letters of credit aggregating $374 million issued as security for performance under certain contracts (December 31, 2017 – $376 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Contingent Payment

In connection with the Acquisition and related to oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at June 30, 2018, the estimated fair value of the contingent payment was $635 million. See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2017 annual MD&A.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pay a dividend to our shareholders and may materially affect the market price of our securities.

The following provides an update on our risks related to commodity prices.

Commodity Prices

Fluctuations in commodity prices and refined product prices impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 22 and 23 to the interim Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus if commodity prices increase. These risks are managed through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

Impact of Financial Risk Management Activities

	Three Months Ended June 30,					
	2018			2017		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [(1)]	**698**	**(109)**	**589**	(14)	(166)	(180)
Refining	**(1)**	**(3)**	**(4)**	2	(3)	(1)
Interest Rate	**-**	**(10)**	**(10)**	-	13	13
Foreign Exchange	**-**	**-**	**-**	(143)	24	(119)
(Gain) Loss on Risk Management	**697**	**(122)**	**575**	(155)	(132)	(287)
Income Tax Expense (Recovery)	**(191)**	**33**	**(158)**	39	37	76
(Gain) Loss on Risk Management, After Tax	**506**	**(89)**	**417**	(116)	(95)	(211)

(1) 2017 excludes $3 million of realized risk management losses on crude oil contracts from our Conventional segment, which have been classified as a discontinued operation.

	Six Months Ended June 30,					
	2018			2017		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [(1)]	**1,161**	**(220)**	**941**	63	(417)	(354)
Refining	**4**	**(6)**	**(2)**	4	(3)	1
Interest Rate	**-**	**(35)**	**(35)**	-	9	9
Foreign Exchange	**1**	**-**	**1**	(143)	-	(143)
(Gain) Loss on Risk Management	**1,166**	**(261)**	**905**	(76)	(411)	(487)
Income Tax Expense (Recovery)	**(317)**	**70**	**(247)**	18	112	130
(Gain) Loss on Risk Management, After Tax	**849**	**(191)**	**658**	(58)	(299)	(357)

(1) 2017 excludes $16 million of realized risk management losses on crude oil contracts from our Conventional segment, which have been classified as a discontinued operation.

In the second quarter of 2018 and on a year-to-date basis, we incurred realized losses on crude oil risk management activities as the settlement prices exceeded our contract prices. The hedging contracts were established to provide downside protection and support financial resilience following the Acquisition. The majority of these hedging contracts have now expired, with only 37 percent of our anticipated liquids production hedged in the second half of 2018 compared with 80 percent hedged for the first six months of the year.

Unrealized gains were recorded on our crude oil financial instruments in the three and six months ended June 30, 2018 primarily due to the realization of settled positions, while partially offset by losses due to WTI and Brent benchmark price increases.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and the interim Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies during the six months ended June 30, 2018. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2017.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty during the six months ended June 30, 2018. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2017.

Changes in Accounting Policies

Effective January 1, 2018, Cenovus adopted IFRS 9, "*Financial Instruments*" ("IFRS 9") replacing IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39"). The adoption of IFRS 9 did not have a material impact on our Consolidated Financial Statements.

Effective January 1, 2018, Cenovus adopted IFRS 15, *"Revenue From Contracts With Customers"* ("IFRS 15") replacing IAS 11, *"Construction Contracts",* IAS 18, *"Revenue"* and several revenue-related interpretations. The adoption of IFRS 15 did not have a material impact on our Consolidated Financial Statements.

Further information about changes to our accounting policies resulting from the adoption of IFRS 9 and IFRS 15 can be found in Note 3 to the interim Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

A description of additional accounting standards and interpretations that will be adopted in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2017. The following provides an update to the disclosure in the annual Consolidated Financial Statements for the year ended December 31, 2017.

Leases

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than twelve months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of applying the standard to prior periods as an adjustment to opening retained earnings. We plan to use the modified retrospective approach in our adoption of IFRS 16.

We have completed an initial assessment of the potential impact on our consolidated financial statements but have not yet completed our detailed assessment. The actual impact of applying IFRS 16 on the consolidated financial statements in the period of initial adoption will depend on future economic conditions, including our borrowing rate at January 1, 2019, the composition of our lease portfolio at the date of adoption, our assessment of whether we will exercise any lease renewal option and the extent we apply the practical expedients available.

We anticipate that the most significant impact of adopting IFRS 16 will be the recognition of right-of-use ("ROU") assets and corresponding lease obligations on our operating leases for office space. In addition, the nature of the expenses related to these leases will change as IFRS 16 replaces the straight-line operating lease expense with depreciation expense on the ROU asset and a finance charge on the lease obligation.

On adoption of IFRS 16, we will recognize lease liabilities in relation to leases under the principles of the new standard. These liabilities will be measured at the present value of the remaining lease payments, discounted using our incremental borrowing rate as at January 1, 2019. The associated ROU asset will be measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

On initial adoption, we intend to use the following practical expedients permitted under the standard. Certain of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets. Management is still evaluating whether certain leases or classes of assets will not be subject to these elections.

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value;
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease; and
- Use our previous assessment of impairment under IAS 37 for onerous contracts instead of re-assessing the ROU asset for impairment on January 1, 2019.

We do not currently intend to apply any grandfathering practical expedients.

We have assembled a multi-disciplinary transition team and have developed a detailed project plan. A process for identifying contracts in order to identify potential leases has been established and we are in the process of performing detailed evaluations of our contracts that are potentially leases under IFRS 16. Implementation is underway for a software solution that will capture and provide the necessary accounting and disclosure requirements of the new standard. Contract assessments, implementation of changes to policies, internal controls, information systems, and business and accounting processes, will continue throughout 2018. In addition, we are evaluating the impact of the new standard on our non-GAAP measures.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

OUTLOOK

We expect the remainder of 2018 will see continued commodity price volatility and market access constraints for Cenovus and our industry. We will continue to look for ways to increase our margins through operating performance and cost leadership, while focusing on safe and reliable operations. Proactively managing our market access commitments and opportunities should assist with our goal of reaching a broader customer base to secure a higher sales price for our liquids production. We expect that transportation challenges faced by our industry will continue to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects in Canada to proceed as soon as possible.

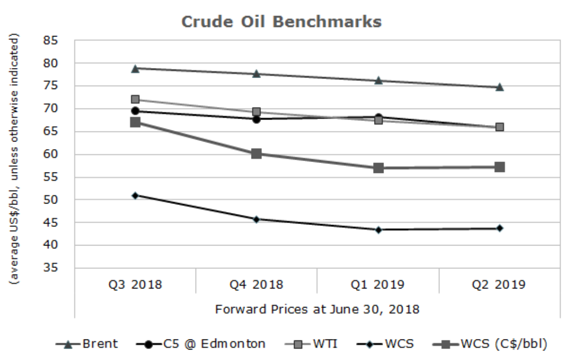
Through a continued focus on capital discipline and cost reductions, we have reduced the amount of capital needed to sustain our base business and expand our projects, which we believe will help to ensure our financial resilience.

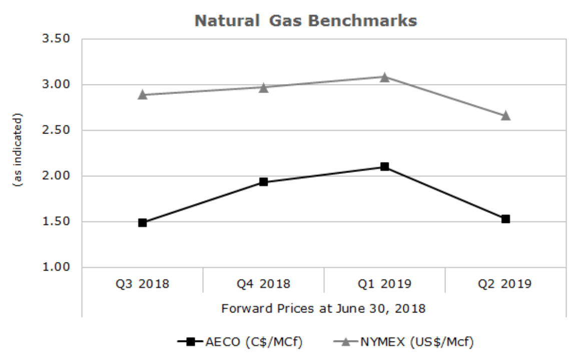
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and the pace of growth in global demand as influenced by macro-economic events;
- Overall, crude oil price volatility is expected to increase as inventories return to historical levels;
- We anticipate the Brent-WTI differential will narrow once additional pipeline capacity out of the Permian basin becomes available in the second half of 2019;
- We expect that the WTI-WCS differential will remain under pressure until additional takeaway capabilities alleviates some of the expected production growth; and
- We anticipate that the pending International Maritime Organization (IMO) regulations will cause light-heavy crude oil price differentials to widen, although the magnitude of the widening remains uncertain.

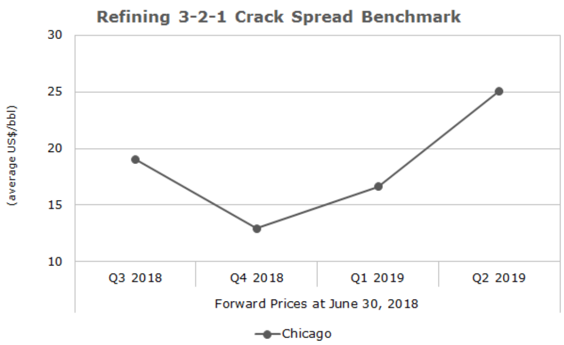


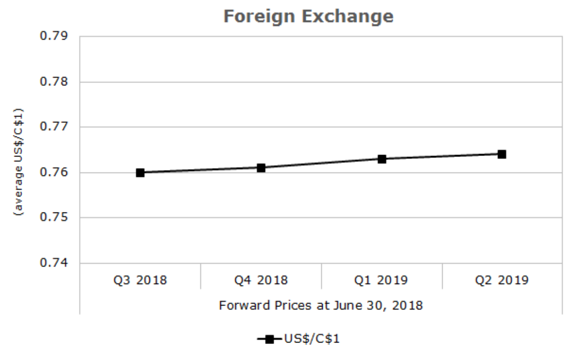


Natural gas prices are anticipated to remain challenged with North American supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain wide as increasing supply is anticipated to exceed the limits of existing pipeline capacity.

Refining crack spreads will likely continue to fluctuate, adjusting for seasonal trends, and will narrow once the Brent-WTI price differential narrows. The wide WTI-WCS and Brent-WTI differentials should provide an incentive for U.S. Midwest and Midcontinent refiners to process additional heavy crude oil volumes from Canada or light sweet crude oil from west Texas. In addition, the wide WTI-WTS differential will continue to benefit refiners who process WTS crude oil as their feedstock costs remain discounted.

We expect the Canadian dollar to continue to be tied to crude oil prices, and the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise benchmark lending rates relative to each other, and emerging macro-economic factors. The Bank of Canada raised its benchmark lending rate twice in 2017 and twice again thus far in 2018, marking a notable shift for Canada towards a tighter monetary policy.





Our exposure to the light-heavy crude oil price differentials is composed of both a global light-heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of swings in light-heavy crude oil price differentials through the following:

- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets, as well as utilizing our crude-by-rail terminal to alleviate takeaway capacity constraints;
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production well rates in response to pipeline capacity constraints, crude-by-rail export capacity and crude oil price differentials.

Natural gas and NGLs production associated with our Deep Basin Assets provide improved upstream integration for the fuel, solvent and blending requirements at our oil sands operations.

Key Priorities For 2018

Cost Reductions and Deleveraging

Our priorities in 2018 are to maintain capital discipline and deleverage our balance sheet in an effort to increase returns to shareholders. We remain focused on maintaining our financial resilience and flexibility while continuing to deliver safe and reliable operations, which remains a top priority.

Over the past three years, we have achieved significant improvements in our operating and sustaining capital costs. In 2018, we continue to target additional capital, operating and general and administrative cost reductions across Cenovus. We expect to realize additional savings through continued improvements in areas such as drilling performance, development planning and optimized scheduling of oil sands well start-ups. Our ability to drive structural and sustainable cost and margin improvements will further support our business plan, financial resilience and our ability to generate shareholder value.

At June 30, 2018, through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $4.9 billion of liquidity. We continue to market for sale a package of non-core Deep Basin assets with production of approximately 15,000 BOE per day, and will look for further opportunities to streamline and high-grade our current portfolio of assets. We believe growth in cash flows, proceeds from additional asset divestitures and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target of less than 2.0 times.

Disciplined Capital Investment

In 2018, we anticipate capital investment to be between $1.5 billion and $1.7 billion. We plan to direct the majority of our 2018 capital budget towards sustaining oil sands production, while supporting ongoing construction at the Christina Lake phase G expansion and a targeted drilling program in the Deep Basin. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

Market Access

Market access constraints for Canadian crude oil production continue to be a challenge. Our strategy is to maintain firm transportation commitments through a combination of pipelines, rail and marine access to support our growth plans, but leave capacity for optimization. We expect to supplement firm capacity with active blending, storage, sourcing and destination optimization to ensure we are maximizing the margin on every barrel we produce.

Advance Focused Technology and Innovation to Achieve Margin Improvement

We have always believed that technology and innovation are differentiating factors in our industry. We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, reduce costs, improve margins and lower emissions. We expect innovation at Cenovus to mean significant improvements and game-changing developments that are implemented to generate value. We aim to complement our internal technology development efforts with external collaboration that will leverage our technology spend.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2017 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities. Estimates are presented using an average of three independent qualified reserves evaluators January 1, 2018 price forecasts. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2017.

Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the U.S. Private Securities Litigation Reform Act of 1995, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "could", "expect", "estimate", "focus", "forecast", "forward", "future", "guidance", "may", "on track", "outlook", "plan", "position", "potential", "priority", "project", "pursue", "schedule", "strategy", "should", "target", "will", or similar expressions and includes suggestions of future outcomes, including statements about: all statements about our strategy and related milestones, schedules and planned tactics in furtherance of them, including focus on maximizing shareholder value through cost leadership and realizing the best margins for our products, and our plans to maintain and demonstrate financial discipline while balancing growth and shareholder return, continuing to advance our operational performance and upholding our trusted reputation; expected timing for oil sands expansion phases and associated expected production capacities; projections for 2018 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; our future opportunities for oil and natural gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; our commitment to continue reducing debt, including our long term target Net Debt to Adjusted EBITDA ratio; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and funding sources thereof; all statements with respect to our 2018 guidance estimates; expected future production, including the timing, stability or growth thereof; our expectation that our capital investment and any cash dividends for 2018 will be funded from internally generated cash flows and cash balance on hand; expected reserves; capacities, including for projects, transportation and refining; all statements related to government royalty regimes applicable to Cenovus, which regimes are subject to change; expected timeline for our Christina Lake project to reach payout for royalty purposes and related royalty rate increase; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost reductions and sustainability thereof; our priorities, including for 2018; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof by Cenovus, and anticipated impact on the Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales;

expected impacts of the contingent payment; future use and development of technology and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future cost reductions; and projected growth and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials and other assumptions identified in Cenovus's 2018 guidance, available at cenovus.com; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; expected condensate prices; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; future narrowing of crude oil differentials; realization of expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when pipeline capacity has improved and crude oil differentials have narrowed; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgements; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; achievement of expected impacts of the Acquisition; successful completion of the integration of the Deep Basin Assets; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and the timelines we expect; forecast bitumen, crude oil, natural gas liquids, condensate and refined products prices, forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized Western Canadian Select ("WCS") prices and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology necessary to achieve expected future results; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2018 guidance, as updated December 13, 2017, assumes: Brent prices of US$55.00/bbl, WTI prices of US$52.00/bbl; WCS of US$37.00/bbl; NYMEX natural gas prices of US$3.00/MMBtu; AECO natural gas prices of $2.20/GJ; Chicago 3-2-1 crack spread of US$15.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: possible failure by us to realize the anticipated benefits of and synergies from the Acquisition; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; possible failure to realize the expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline capacity and crude oil differentials have improved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; possible lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, future production and future net revenue estimates; accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Statements relating to “reserves” are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see “Risk Management and Risk Factors” in our MD&A for the period ended December 31, 2017, available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com and the updates under “Risk Management and Risk Factors” in this MD&A.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrel of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
CDB	Christina Dilbit Blend		
MSW	Mixed Sweet Blend		

NETBACK RECONCILIATIONS

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our interim Consolidated Financial Statements.

Total Production From Continuing Operations

Continuing Upstream Financial Results

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended June 30, 2018 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	3,248	241	3,489	(1,425)	-	(34)	(20)	2,010
Royalties	179	16	195	-	-	-	-	195
Transportation and Blending	1,642	27	1,669	(1,425)	-	-	(4)	240
Operating	263	109	372	-	-	(34)	(9)	329
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	1,164	88	1,252	-	-	-	(7)	1,245
(Gain) Loss on Risk Management	688	10	698	-	-	-	-	698
Operating Margin	476	78	554	-	-	-	(7)	547

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended June 30, 2017 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	1,666	124	1,790	(719)	-	-	(6)	1,065
Royalties	36	8	44	-	-	-	-	44
Transportation and Blending	879	10	889	(719)	-	-	(2)	168
Operating	264	55	319	-	-	-	(52)	267
Netback	487	51	538	-	-	-	48	586
(Gain) Loss on Risk Management	(14)	-	(14)	-	-	-	-	(14)
Operating Margin	501	51	552	-	-	-	48	600

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Six Months Ended June 30, 2018 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	5,654	500	6,154	(2,699)	-	(97)	(34)	3,324
Royalties	237	51	288	-	-	-	-	288
Transportation and Blending	3,134	52	3,186	(2,699)	-	-	(4)	483
Operating	559	200	759	-	-	(97)	(21)	641
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	1,724	196	1,920	-	-	-	(9)	1,911
(Gain) Loss on Risk Management	1,142	19	1,161	-	-	-	-	1,161
Operating Margin	582	177	759	-	-	-	(9)	750

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Six Months Ended June 30, 2017 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	2,728	124	2,852	(1,197)	-	-	(11)	1,644
Royalties	63	8	71	-	-	-	-	71
Transportation and Blending	1,445	10	1,455	(1,197)	-	-	(2)	256
Operating	404	55	459	-	-	-	(53)	406
Netback	816	51	867	-	-	-	44	911
(Gain) Loss on Risk Management	63	-	63	-	-	-	-	63
Operating Margin	753	51	804	-	-	-	44	848

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.

Oil Sands

Three Months Ended June 30, 2018 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements[1]: Total Oil Sands
Gross Sales	842	979	1,821	-	1,425	-	2	3,248
Royalties	142	37	179	-	-	-	-	179
Transportation and Blending	117	100	217	-	1,425	-	-	1,642
Operating	136	125	261	-	-	-	2	263
Netback	447	717	1,164	-	-	-	-	1,164
(Gain) Loss on Risk Management	304	384	688	-	-	-	-	688
Operating Margin	143	333	476	-	-	-	-	476

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements[1]: Total Oil Sands
Gross Sales	429	514	943	4	719	-	-	1,666
Royalties	24	12	36	-	-	-	-	36
Transportation and Blending	100	58	158	-	719	-	2	879
Operating	119	99	218	2	-	-	44	264
Netback	186	345	531	2	-	-	(46)	487
(Gain) Loss on Risk Management	(9)	(5)	(14)	-	-	-	-	(14)
Operating Margin	195	350	545	2	-	-	(46)	501

Six Months Ended June 30, 2018 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements[1]: Total Oil Sands
Gross Sales	1,421	1,529	2,950	1	2,699	-	4	5,654
Royalties	189	48	237	-	-	-	-	237
Transportation and Blending	248	187	435	-	2,699	-	-	3,134
Operating	291	259	550	2	-	-	7	559
Netback	693	1,035	1,728	(1)	-	-	(3)	1,724
(Gain) Loss on Risk Management	504	638	1,142	-	-	-	-	1,142
Operating Margin	189	397	586	(1)	-	-	(3)	582

Six Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements[1]: Total Oil Sands
Gross Sales	716	804	1,520	6	1,197	-	5	2,728
Royalties	44	19	63	-	-	-	-	63
Transportation and Blending	155	91	246	-	1,197	-	2	1,445
Operating	190	164	354	5	-	-	45	404
Netback	327	530	857	1	-	-	(42)	816
(Gain) Loss on Risk Management	31	32	63	-	-	-	-	63
Operating Margin	296	498	794	1	-	-	(42)	753

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Deep Basin

Three Months Ended June 30, 2018 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[1]
	Total	Other[2]	Total Deep Basin
Gross Sales	223	18	241
Royalties	16	-	16
Transportation and Blending	23	4	27
Operating	102	7	109
Production and Mineral Taxes	1	-	1
Netback	81	7	88
(Gain) Loss on Risk Management	10	-	10
Operating Margin	71	7	78

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[1]
	Total	Other[2]	Total Deep Basin
Gross Sales	118	6	124
Royalties	8	-	8
Transportation and Blending	10	-	10
Operating	47	8	55
Netback	53	(2)	51
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	(2)	51

Six Months Ended June 30, 2018 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[1]
	Total	Other[2]	Total Deep Basin
Gross Sales	470	30	500
Royalties	51	-	51
Transportation and Blending	48	4	52
Operating	186	14	200
Production and Mineral Taxes	1	-	1
Netback	184	12	196
(Gain) Loss on Risk Management	19	-	19
Operating Margin	165	12	177

Six Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[1]
	Total	Other[2]	Total Deep Basin
Gross Sales	118	6	124
Royalties	8	-	8
Transportation and Blending	10	-	10
Operating	47	8	55
Netback	53	(2)	51
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	(2)	51

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

	Three Months Ended June 30,		Six Months Ended June 30,	
(barrels per day, unless otherwise stated)	**2018**	2017	**2018**	2017
Oil Sands				
Foster Creek	**171,083**	106,115	**167,517**	92,415
Christina Lake	**220,779**	154,431	**211,546**	122,353
Total Oil Sands Crude Oil	**391,862**	260,546	**379,063**	214,768
Natural Gas (MMcf per day)	**1**	12	**2**	13
Total Oil Sands (BOE per day)	**391,948**	262,544	**379,474**	216,992
Deep Basin				
Total Liquids	**34,041**	16,894	**34,756**	8,494
Natural Gas (MMcf per day)	**570**	253	**560**	127
Total Deep Basin (BOE per day)	**129,066**	58,981	**128,067**	29,654
Less: Internal Consumption (1) (MMcf per day)	**(300)**	-	**(311)**	-
Sales From Continuing Operations (1) (BOE per day)	**471,013**	321,526	**455,709**	246,646

(1) Less natural gas volumes used for internal consumption by the Oil Sands segment.