



## MANAGEMENT'S DISCUSSION AND ANALYSIS FOR THE PERIOD ENDED SEPTEMBER 30, 2019

<a href="#">OVERVIEW OF CENOVUS</a> .....	2
<a href="#">QUARTERLY HIGHLIGHTS</a> .....	2
<a href="#">OPERATING RESULTS</a> .....	3
<a href="#">COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS</a> .....	5
<a href="#">FINANCIAL RESULTS</a> .....	8
<a href="#">REPORTABLE SEGMENTS</a> .....	14
<a href="#">OIL SANDS</a> .....	14
<a href="#">DEEP BASIN</a> .....	21
<a href="#">REFINING AND MARKETING</a> .....	24
<a href="#">CORPORATE AND ELIMINATIONS</a> .....	26
<a href="#">DISCONTINUED OPERATIONS</a> .....	28
<a href="#">LIQUIDITY AND CAPITAL RESOURCES</a> .....	28
<a href="#">RISK MANAGEMENT AND RISK FACTORS</a> .....	31
<a href="#">CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES</a> .....	32
<a href="#">CONTROL ENVIRONMENT</a> .....	33
<a href="#">OUTLOOK</a> .....	33
<a href="#">ADVISORY</a> .....	36
<a href="#">ABBREVIATIONS</a> .....	39
<a href="#">NETBACK RECONCILIATIONS</a> .....	40

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 October 30, 2019, should be read in conjunction with our September 30, 2019 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2018 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2018 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of October 30, 2019, 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 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](http://sedar.com), on EDGAR at [sec.gov](http://sec.gov), and on our website at [cenovus.com](http://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, (which includes references to "dollar" or "\$"), 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. We adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

### 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, 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 7 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 September 30, 2019, we had an enterprise value of approximately \$23 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 approximately 448,000 BOE per day for the three months ended September 30, 2019. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 465,000 gross barrels per day of crude oil feedstock into an average of 485,000 gross barrels per day of refined products in the three months ended September 30, 2019.

On October 2, 2019, we announced our updated five-year business plan. Our corporate strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our business plan through 2024 will focus on sustainably growing shareholder returns and further reducing Net Debt. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility and give us the flexibility to proceed with opportunities at all points in the price cycle. We aim to evaluate disciplined investment in our portfolio against dividend increases, share repurchases and maintaining the optimal debt level while retaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage. We plan to achieve our strategy by leveraging our strategic focus areas including oil sands, conventional oil and natural gas assets, marketing, transportation and refining portfolio, and our people.

For a description of our operations, refer to the Reportable Segments section of this MD&A.

## QUARTERLY HIGHLIGHTS

---

Cenovus continued to deliver good operating and financial results in the third quarter of 2019. In line with our strategy to sustainably grow shareholder returns, the Board of Directors approved a 25 percent increase in the dividend to \$0.0625 per share for the fourth quarter of 2019.

Our Oil Sands production during the third quarter averaged 354,595 barrels per day, generally in line with the Government of Alberta's mandatory production curtailment program restrictions. Production from our Deep Basin assets of 93,901 BOE per day decreased from the third quarter of 2018 due to natural declines from lower sustaining capital investment, the divestiture of Cenovus Pipestone Partnership ("CPP") and temporary shut-ins resulting from low natural gas prices.

We have continued to ramp up our crude-by-rail capacity and are on track to achieve 100,000 barrels per day by the end of 2019. In the quarter, using our fleet of leased railcars, 68,380 barrels per day were loaded for delivery to U.S. destinations. Of these volumes, we sold an average of 62,789 barrels per day, allowing us to capture higher global prices. We exited the quarter with September loaded volumes averaging nearly 83,000 barrels per day and sales of 80,862 barrels per day.

Average Brent and West Texas Intermediate ("WTI") benchmark prices were lower than the third quarter of 2018. At the same time, the differential between WTI and Western Canadian Select ("WCS") benchmark prices narrowed supported by the Government of Alberta's mandatory production curtailment program. As a result, the average WCS benchmark crude oil price in Alberta decreased, averaging US\$44.21 per barrel in the third quarter of 2019 compared with US\$47.25 per barrel in the same period of 2018.

With market access constraints for Canadian crude oil production continuing to be a challenge, we have made good progress on our strategy to maintain firm transportation through a combination of pipelines, rail and marine access. In the quarter, we transported approximately one third of our Oil Sands production out of Alberta to U.S. destinations compared with less than 20 percent in 2018. This contributed to the increase in our average realized crude oil sales price to \$55.13 per barrel from \$49.73 per barrel in 2018 along with narrower differentials.

Operating Margin for our Oil Sands segment increased in the quarter to \$917 million compared with \$682 million in 2018 due to an increase in our average realized crude oil sales price, lower transportation and blending costs, and an increase in realized risk management gains compared with losses in 2018, partially offset by lower sales volumes. In the third quarter of 2019, Deep Basin Operating Margin of \$37 million declined due a decrease in our realized sales price and lower sales volumes, partially offset by lower operating costs.

Refining operational performance in the quarter was impacted by unplanned outages and the startup of planned turnaround activities in September at the Wood River and Borger refineries ("the Refineries"). This was partially offset by Wood River achieving a record monthly crude oil run rate in July. Our Refining and Marketing segment generated operating margin of \$126 million, down from the third quarter of 2018, due to lower crude advantage from narrower crude oil differentials, lower market crack spreads, decreased crude oil runs due to unplanned outages and planned turnarounds at the Refineries, and higher operating costs.

In the third quarter of 2019, we:

- Achieved Cash from Operating Activities of \$834 million and Adjusted Funds Flow of \$916 million;
- Attained Net Debt of \$6.8 billion as at September 30, 2019. Subsequent to September 30, 2019, we repaid in full our maturing 5.70 percent unsecured notes with a remaining principal amount of US\$500 million and repurchased a further US\$13 million of our 4.45 percent unsecured notes;
- Realized Operating Earnings from continuing operations of \$284 million (2018 – Operating Loss of \$41 million);
- Recorded Net Earnings from continuing operations of \$187 million (2018 – Net Loss of \$242 million);
- Increased our realized crude oil sales price, averaging \$55.13 per barrel through increased U.S. sales;
- Earned an average companywide Netback from continuing operations of \$25.68 per BOE, before realized hedging; and
- Invested \$294 million on sustaining capital, refined product yield enhancement projects, rail initiatives, and corporate infrastructure.

## OPERATING RESULTS

### Upstream Production Volumes

	Three Months Ended September 30, Percent Change			Nine Months Ended September 30, Percent Change		
	2019		2018	2019		2018
<b>Continuing Operations</b>						
<b>Liquids</b> (barrels per day)						
<b>Oil Sands</b>						
Foster Creek	156,527	(5)	163,939	158,888	(3)	164,160
Christina Lake	198,068	(7)	212,733	188,671	(11)	211,141
	354,595	(6)	376,672	347,559	(7)	375,301
<b>Deep Basin</b>						
Crude Oil	4,929	(13)	5,674	4,885	(21)	6,148
NGLs	21,175	(20)	26,595	21,950	(21)	27,770
	26,104	(19)	32,269	26,835	(21)	33,918
<b>Liquids Production</b> (barrels per day)	380,699	(7)	408,941	374,394	(9)	409,219
<b>Natural Gas</b> (MMcf per day)						
Oil Sands	-	-	-	-	(100)	2
Deep Basin <sup>(1)</sup>	407	(22)	520	432	(21)	546
	407	(22)	520	432	(21)	548
<b>Production From Continuing Operations</b> (BOE per day)	448,496	(10)	495,592	446,366	(11)	500,558
<b>Production From Discontinued Operations</b> (Conventional) (BOE per day)	-	(100)	16	-	(100)	394
<b>Total Production</b> (BOE per day)	448,496	(10)	495,608	446,366	(11)	500,952

(1) Includes production used for internal consumption by the Oil Sands segment of 304 MMcf per day and 314 MMcf per day for the three and nine months ended September 30, 2019, respectively (2018 – 293 MMcf per day and 305 MMcf per day, respectively).

Oil Sands production continues to be limited by the Government of Alberta's mandatory production curtailments. On a year-to-date basis, Oil Sands production was lower compared with 2018 due to mandatory production curtailments and a planned turnaround at Christina Lake during the second quarter of 2019.

Deep Basin production for the three and nine months ended September 30, 2019 decreased compared with the same periods in 2018 due to natural declines from the lower sustaining capital investment, the divestiture of CPP on September 6, 2018, and temporary shut-ins resulting from low natural gas prices.

### 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 September 30,		Nine Months Ended September 30,	
(\$/BOE)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Sales Price	51.48	45.73	52.15	42.11
Royalties	9.07	6.91	7.99	4.63
Transportation and Blending	9.39	5.66	7.89	5.79
Operating Expenses	7.33	7.10	8.13	7.55
Production and Mineral Taxes	0.01	0.01	0.01	0.01
<b>Netback Excluding Realized Risk Management <sup>(2)</sup></b>	<b>25.68</b>	26.05	<b>28.13</b>	24.13
Realized Risk Management Gain (Loss)	0.19	(8.00)	(0.36)	(12.05)
<b>Netback Including Realized Risk Management <sup>(2)</sup></b>	<b>25.87</b>	18.05	<b>27.77</b>	12.08

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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

Our average Netback, excluding realized risk management gains and losses, decreased in the third quarter of 2019 compared with the third quarter of 2018, primarily due to higher realized sales prices being offset by higher per-unit transportation and blending costs, higher per-unit royalties, higher per-unit operating costs, and lower sales volumes. On a year-to-date basis, our average Netback increased compared with 2018 due to higher realized sales prices, partially offset by higher per-unit royalties, higher per-unit transportation and blending costs, higher per-unit operating costs and lower sales volumes. On a quarterly and year-to-date basis, the weakening of the Canadian dollar relative to the U.S dollar compared with 2018 had a positive impact on our reported sales price of approximately \$0.54 per BOE and approximately \$1.68 per BOE, respectively.

In the three and nine months ended September 30, 2019, we sold approximately one third and one quarter of our Oil Sands production, respectively, at sales locations outside of Alberta, contributing to the increase in our realized sales prices and transportation and blending costs.

## Refining and Marketing

In the third quarter of 2019, operational performance was impacted by unplanned outages and the startup of planned turnaround activities at both Refineries, which reduced crude oil runs. Wood River ran at capacity despite the planned and unplanned outages, and achieved a record monthly crude oil run rate in July. On a year-to-date basis, crude oil runs and refined product output increased slightly as planned turnarounds and unplanned maintenance in 2019, including a fire in a crude unit at Wood River in the first quarter of 2019, had less of an impact than the major planned turnarounds completed at both Refineries in the first quarter of 2018.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2019	Percent Change	2018	2019	Percent Change	2018
Crude Oil Capacity (Mbbbls/d)	482	5	460	482	5	460
Crude Oil Runs <sup>(1)</sup> (Mbbbls/d)	465	(5)	492	438	-	436
Heavy Crude Oil <sup>(1)</sup>	185	(9)	204	174	(8)	190
Refined Product <sup>(1)</sup> (Mbbbls/d)	485	(6)	518	463	1	459
Crude Utilization <sup>(1)</sup> (percent)	96	(11)	107	91	(4)	95
Operating Margin <sup>(2)</sup> (\$ millions)	126	(71)	436	628	(16)	745

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A.

We continue to increase total volumes loaded at our Bruderheim crude-by-rail terminal. In the three months ended September 30, 2019, volumes loaded at the terminal averaged 64,773 barrels per day compared with an average of 43,018 barrels per day in the third quarter of 2018.

In the third quarter of 2019, Operating Margin from our Refining and Marketing segment decreased compared with 2018 due to lower crude advantage from narrowing heavy and medium sour crude oil differentials, lower market crack spreads, decreased crude oil runs and higher operating costs. Operating Margin decreased year-over-year due to reduced crude advantage from narrowing heavy and medium sour crude oil differentials, partially offset by higher margins on fixed priced products due to a lower benchmark WTI, lower operating expenses as a result of major planned turnarounds at both Refineries in the first quarter of 2018 and a reduction in the cost of Renewable Identification Numbers ("RINs").

Further information on the changes in our production volumes and other 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 interim Consolidated Financial Statements.

## COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, quality and location 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 <sup>(1)</sup>

	Nine Months Ended September 30,					
(US\$/bbl, unless otherwise indicated)	2019	Percent Change	2018	Q3 2019	Q2 2019	Q3 2018
<b>Brent</b>						
Average	64.74	(11)	72.68	62.00	68.34	75.97
End of Period	60.78	(27)	82.72	60.78	66.55	82.72
<b>WTI</b>						
Average	57.06	(15)	66.75	56.45	59.83	69.50
End of Period	54.07	(26)	73.25	54.07	58.47	73.25
Average Differential Brent-WTI	7.68	30	5.93	5.55	8.51	6.47
<b>WCS</b>						
Average	45.32	1	44.82	44.21	49.18	47.25
Average (C\$/bbl)	60.26	4	57.69	58.38	65.80	61.75
End of Period	41.06	9	37.75	41.06	45.48	37.75
Average Differential WTI-WCS	11.74	(46)	21.93	12.24	10.65	22.25
<b>West Texas Sour ("WTS")</b>						
Average	55.93	(5)	58.86	55.88	58.18	55.48
End of Period	54.24	(19)	66.85	54.24	58.37	66.85
Average Differential WTI-WTS	1.13	(86)	7.89	0.57	1.65	14.02
<b>Condensate (C5 @ Edmonton)</b>						
Average	52.81	(20)	66.23	52.02	55.87	66.82
Average (C\$/bbl)	70.21	(18)	85.24	68.72	74.74	87.35
Average Differential WTI-Condensate (Premium)/Discount	4.25	717	0.52	4.43	3.96	2.68
Average Differential WCS-Condensate (Premium)/Discount	(7.49)	(65)	(21.41)	(7.81)	(6.69)	(19.57)
<b>Mixed Sweet Blend ("MSW" @ Edmonton)</b>						
Average	52.35	(14)	60.69	51.79	55.21	62.67
Average (C\$/bbl)	69.59	(11)	78.11	68.43	73.87	81.92
End of Period	48.16	(10)	53.25	48.16	52.48	53.25
<b>Average Refined Product Prices</b>						
Chicago Regular Unleaded Gasoline ("RUL")	72.45	(11)	81.73	72.07	81.23	87.10
Chicago Ultra-low Sulphur Diesel ("ULSD")	77.92	(11)	87.58	75.34	81.29	92.33
<b>Refining Margin: Average 3-2-1 Crack Spreads <sup>(2)</sup></b>						
Chicago	17.24	2	16.82	16.72	21.44	19.14
Group 3	17.36	(1)	17.47	17.32	19.99	18.71
<b>Average Natural Gas Prices</b>						
AECO <sup>(3)</sup> (C\$/Mcf)	1.39	(1)	1.41	1.04	1.17	1.35
NYMEX (US\$/Mcf)	2.67	(8)	2.90	2.23	2.64	2.90
Basis Differential NYMEX-AECO (US\$/Mcf)	1.63	(9)	1.80	1.44	1.76	1.88
<b>Foreign Exchange Rate (US\$ per C\$1)</b>						
Average	0.752	(3)	0.777	0.757	0.748	0.765
End of Period	0.755	(2)	0.773	0.755	0.764	0.773

(1) These benchmark prices are not our realized sales prices and represent approximate values. 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.

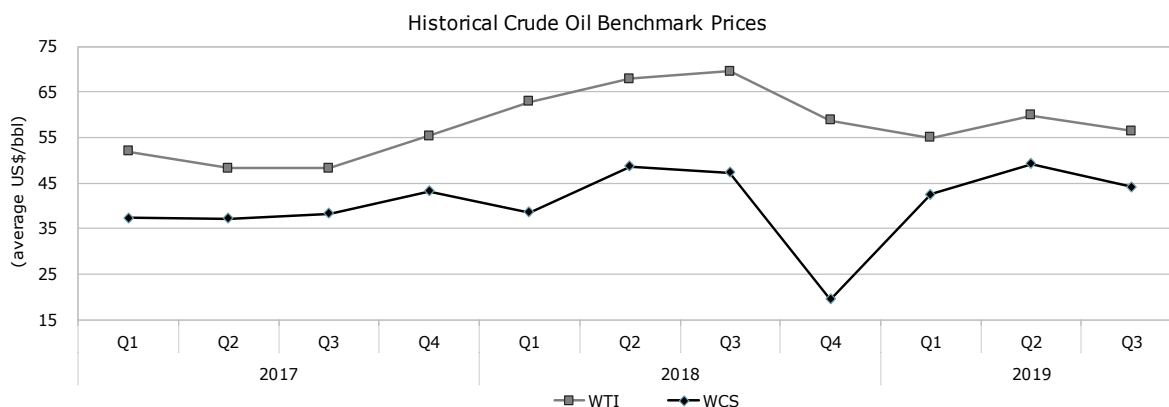
(3) Alberta Energy Company ("AECO") natural gas monthly index.

## Crude Oil Benchmarks

The average Brent and WTI crude oil benchmark prices were lower compared with the third quarter of 2018 as continued uncertainty from oversupply and decreased demand for crude oil due to increased U.S.-China tariffs and trade tensions lowered crude oil benchmark pricing. Global prices increased late in the quarter due to crude oil supply disruptions in Saudi Arabia. Over the nine months of 2019, compared with the same period of 2018, global prices were lower but continued to be supported by the Organization of the Petroleum Exporting Countries ("OPEC") led production cuts and by turmoil in Venezuela, which reduced the country's crude oil supply.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In the third quarter of 2019, the Brent-WTI differential decreased compared with 2018 as a result of increasing takeaway capacity from the Permian to the U.S. Gulf Coast, which eased congestion at Cushing, Oklahoma.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in the third quarter of 2019 and on a year-to-date basis compared with 2018. Heavy oil differentials have narrowed in 2019 in response to production curtailments mandated by the Government of Alberta to address record high differentials in the fourth quarter of 2018 and high levels of crude oil in storage. Decreased production due to mandatory curtailments continues to support Alberta benchmark prices.



WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The differential between WTI and WTS benchmark prices has narrowed significantly in 2019 due to additional pipeline capacity coming online, which helped to remove takeaway constraints in the Permian Basin.

Blending condensate with bitumen enables our production to be transported. Our blending ratios, calculated as 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 benchmark prices were at a wider discount relative to WTI in the third quarter of 2019 and on a year-to-date basis compared with the same periods of 2018 due to increasing North American supply and lower demand as production curtailments in Alberta were implemented.

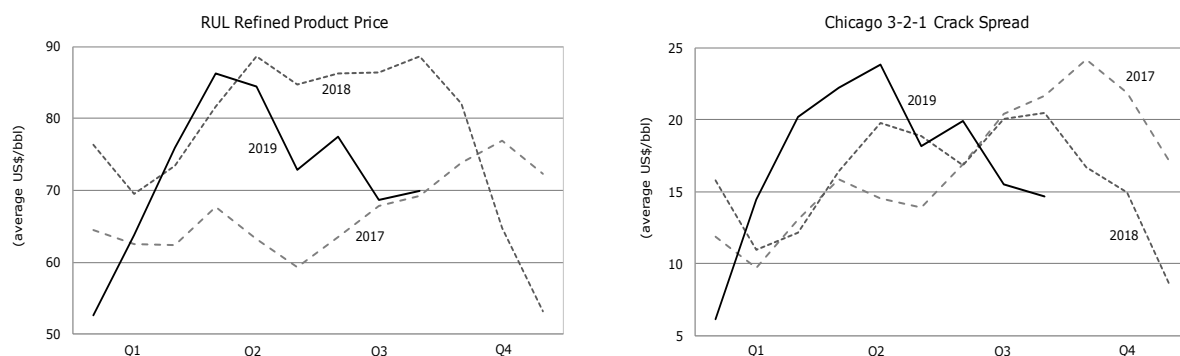
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin assets. The average MSW benchmark price declined in the third quarter of 2019 compared with 2018, consistent with the general decrease 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 market crack spread. The 3-2-1 market 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 decreased on a year-to-date and quarterly basis in 2019 compared with the same periods of 2018 primarily due to lower global crude oil prices. 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.

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 nine months ended September 30, 2019 compared with 2018 due to oversupply and pipeline maintenance in the Alberta market. Average NYMEX prices decreased compared with 2018 due to supply continuing to be high from the development of U.S. shale gas and natural gas associated with crude 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.

The average Canadian dollar weakened relative to the U.S. dollar in 2019, compared with 2018, resulting in a positive impact of approximately \$492 million on our revenues in the nine months ended September 30, 2019. The strengthening of the Canadian dollar relative to the U.S. dollar as at September 30, 2019 compared with December 31, 2018, and the derecognition of unrealized foreign exchange losses, which were realized due to the repurchase of our unsecured notes, resulted in \$542 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

In 2019, the impact of mandatory production curtailments, declining benchmark crude oil prices, narrower light-heavy crude oil price differentials, lower refining throughput, and lower blending costs were the primary drivers of our financial results. The following key performance measures are discussed in more detail within this MD&A.

(\$ millions, except per share amounts)	Nine Months Ended September 30,		2019			2018 <sup>(1)</sup>				2017 <sup>(1)</sup>	
	2019	2018 <sup>(1)</sup>	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
<b>Revenues</b>	<b>15,343</b>	16,299	<b>4,736</b>	5,603	5,004	4,545	5,857	5,832	4,610	5,079	4,386
<b>Operating Margin <sup>(2)</sup></b>											
From Continuing Operations	<b>3,596</b>	2,259	<b>1,080</b>	1,277	1,239	135	1,191	911	157	1,018	1,097
Total Operating Margin	<b>3,596</b>	2,299	<b>1,080</b>	1,277	1,239	132	1,192	938	169	1,088	1,214
<b>Cash From Operating Activities</b>											
From Continuing Operations	<b>2,545</b>	1,630	<b>834</b>	1,275	436	488	1,258	506	(134)	833	481
Total Cash From Operating Activities	<b>2,545</b>	1,669	<b>834</b>	1,275	436	485	1,259	533	(123)	900	592
<b>Adjusted Funds Flow <sup>(3)</sup></b>											
From Continuing Operations	<b>3,046</b>	1,670	<b>916</b>	1,082	1,048	(33)	976	747	(53)	796	865
Total Adjusted Funds Flow	<b>3,046</b>	1,710	<b>916</b>	1,082	1,048	(36)	977	774	(41)	866	980
<b>Operating Earnings (Loss) <sup>(3)</sup></b>											
From Continuing Operations	<b>620</b>	(1,085)	<b>284</b>	267	69	(1,670)	(41)	(292)	(752)	(533)	240
Per Share (\$) <sup>(4)</sup>	<b>0.50</b>	(0.88)	<b>0.23</b>	0.22	0.06	(1.36)	(0.03)	(0.24)	(0.61)	(0.43)	0.20
Total Operating Earnings (Loss)	<b>620</b>	(1,057)	<b>284</b>	267	69	(1,672)	(42)	(272)	(743)	(514)	327
Per Share (\$) <sup>(4)</sup>	<b>0.50</b>	(0.86)	<b>0.23</b>	0.22	0.06	(1.36)	(0.03)	(0.22)	(0.60)	(0.42)	0.27
<b>Net Earnings (Loss)</b>											
From Continuing Operations	<b>2,081</b>	(1,566)	<b>187</b>	1,784	110	(1,350)	(242)	(410)	(914)	(776)	275
Per Share (\$) <sup>(4)</sup>	<b>1.69</b>	(1.27)	<b>0.15</b>	1.45	0.09	(1.10)	(0.20)	(0.33)	(0.74)	(0.63)	0.22
Total Net Earnings (Loss)	<b>2,081</b>	(1,313)	<b>187</b>	1,784	110	(1,356)	(241)	(418)	(654)	620	(82)
Per Share (\$) <sup>(4)</sup>	<b>1.69</b>	(1.06)	<b>0.15</b>	1.45	0.09	(1.10)	(0.20)	(0.34)	(0.53)	0.50	(0.07)
<b>Capital Investment <sup>(5)</sup></b>											
From Continuing Operations	<b>859</b>	1,087	<b>294</b>	248	317	276	271	294	522	557	396
Total Capital Investment	<b>859</b>	1,087	<b>294</b>	248	317	276	271	292	524	583	438
<b>Dividends</b>	<b>183</b>	183	<b>60</b>	62	61	62	61	62	60	61	62
Per Share (\$) <sup>(4)</sup>	<b>0.15</b>	0.15	<b>0.05</b>	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Additional subtotal found in Notes 1 and 7 of the interim Consolidated Financial Statements and defined in this MD&A.

(3) Non-GAAP measure defined in this MD&A.

(4) Represented on a basic and diluted per share basis.

(5) 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	Nine Months Ended
<b>Revenues for the Periods Ended September 30, 2018</b>	<b>5,857</b>	<b>16,299</b>
Increase (Decrease) due to:		
Oil Sands	<b>(331)</b>	<b>(782)</b>
Deep Basin	<b>(68)</b>	<b>(171)</b>
Refining and Marketing	<b>(706)</b>	<b>(177)</b>
Corporate and Eliminations	<b>(16)</b>	<b>174</b>
<b>Revenues for the Periods Ended September 30, 2019</b>	<b>4,736</b>	<b>15,343</b>

Upstream revenues decreased in 2019 compared with 2018 due to lower sales volumes and higher royalties, partially offset by higher realized pricing.

Refining and Marketing revenues for the three and nine months ended September 30, 2019 decreased compared with the same periods in 2018. Refining revenues decreased in the quarter due to lower refined product pricing consistent with the decline in average refined product benchmark prices and lower volumes. The decrease on a year-to-date basis was due to lower refined product pricing. Revenues from third-party crude oil and natural gas

sales undertaken by our marketing group decreased on a quarterly basis in 2019 compared with 2018 due to a decrease in crude oil volumes and lower prices, partially offset by higher natural gas volumes. On a year-to-date basis, marketing revenues increased due to higher crude oil and natural gas volumes partially offset by lower 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 7 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 September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
<b>Gross Sales</b>	<b>5,273</b>	6,332	<b>16,638</b>	17,495
Less: Royalties	<b>332</b>	286	<b>847</b>	574
<b>Revenues</b>	<b>4,941</b>	6,046	<b>15,791</b>	16,921
<b>Expenses</b>				
Purchased Product	<b>2,042</b>	2,483	<b>6,646</b>	6,664
Transportation and Blending	<b>1,269</b>	1,502	<b>3,798</b>	4,688
Operating Expenses	<b>559</b>	542	<b>1,726</b>	1,816
Production and Mineral Taxes	<b>1</b>	-	<b>1</b>	1
Realized (Gain) Loss on Risk Management Activities	<b>(10)</b>	328	<b>24</b>	1,493
<b>Operating Margin From Continuing Operations</b>	<b>1,080</b>	1,191	<b>3,596</b>	2,259
Conventional (Discontinued Operations)	-	1	-	40
<b>Total Operating Margin</b>	<b>1,080</b>	<b>1,192</b>	<b>3,596</b>	<b>2,299</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

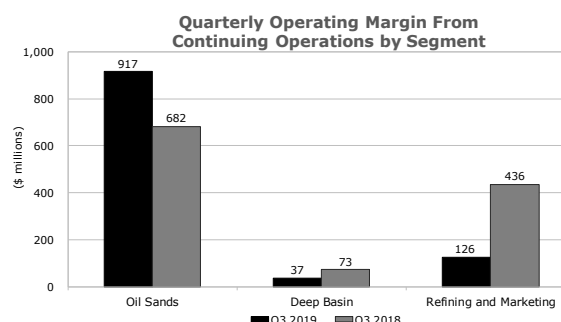
### Three Months Ended September 30, 2019 Compared With September 30, 2018

Operating Margin from continuing operations decreased primarily due to:

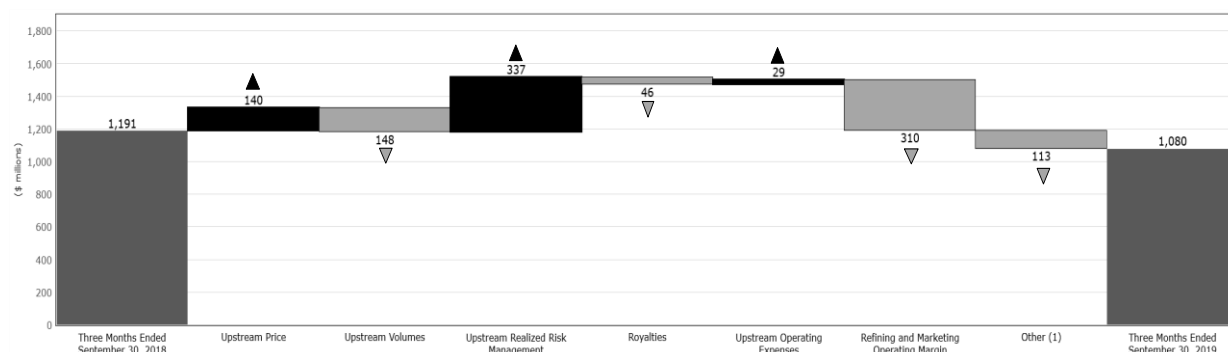
- Lower Operating Margin from our Refining and Marketing segment due to lower crude advantage, lower market crack spreads, lower crude oil runs and higher operating expenses;
- Lower crude oil and natural gas sales volumes; and
- Higher royalties.

These decreases in Operating Margin were partially offset by:

- A decrease in our transportation and blending costs due to a decrease in condensate volumes required for blending and lower condensate prices, partially offset by an increase in rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.;
- An increase in our average crude oil sales prices due to increased U.S. sales and narrower differentials; and
- Upstream realized risk management gains of \$7 million (2018 – losses of \$330 million).



### 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.

### Nine Months Ended September 30, 2019 Compared With September 30, 2018

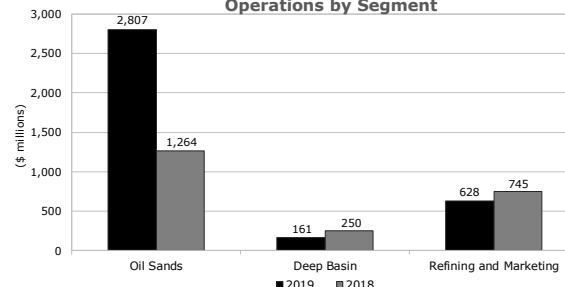
Operating Margin from continuing operations increased in 2019 compared with 2018 primarily due to:

- An increase in our average crude oil sales price due to narrower differentials and higher U.S. sales;
- A decrease in transportation and blending expenses due to a reduction in condensate volumes required for blending and lower condensate prices, partially offset by increased rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.;
- Lower upstream operating expenses; and
- Upstream realized risk management losses of \$38 million (2018 – losses of \$1,491 million).

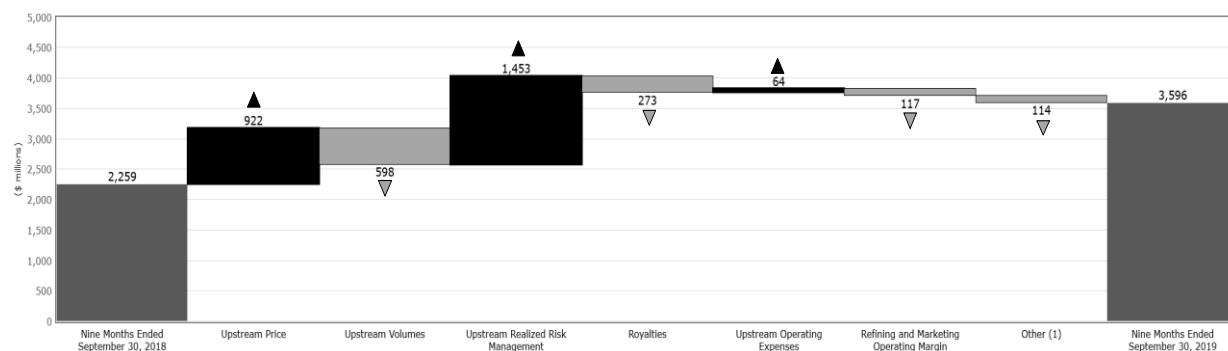
These increases in Operating Margin were partially offset by:

- Lower sales volumes;
- Higher royalties primarily due to Christina Lake achieving payout in August 2018; and
- Lower Operating Margin from our Refining and Marketing segment due to reduced crude advantage.

### Year-to-Date Operating Margin From Continuing Operations by Segment



### 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 accounts receivable, inventories, income tax receivable, accounts payable and income tax payable. 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1) (2)</sup>
<b>Cash From Operating Activities</b>	<b>834</b>	1,259	<b>2,545</b>	1,669
(Add) Deduct:				
Net Change in Other Assets and Liabilities	(21)	(15)	(55)	(50)
Net Change in Non-Cash Working Capital	(61)	297	(446)	9
<b>Adjusted Funds Flow</b>	<b>916</b>	977	<b>3,046</b>	1,710

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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

Cash From Operating Activities and Adjusted Funds Flow were lower in the third quarter of 2019 compared with 2018 due to lower Operating Margin, as discussed above, partially offset by lower finance costs and lower general and administrative costs. The change in non-cash working capital in the third quarter of 2019 was due to higher inventories and a decrease in accounts payable, partially offset by a decrease in accounts receivable and income tax receivable. For the three months ended September 30, 2018, the change in non-cash working capital was primarily due to a decrease in accounts receivable and income tax receivable, partially offset by a rise in inventory.

Cash From Operating Activities and Adjusted Funds Flow were higher on a year-to-date basis compared with 2018 due to higher Operating Margin, lower general and administrative costs due to a \$72 million reduction in rent expense primarily due to the adoption of IFRS 16 and \$48 million of severance costs incurred in 2018, and lower finance costs, partially offset by a lower current income tax recovery. The change in non-cash working capital for the nine months ended September 30, 2019 was primarily due to an increase in inventory and accounts receivable, partially offset by a decrease in income tax receivable and increase in accounts payable. In 2018, the change in non-cash working capital was primarily due to a decline in income tax receivable and an increase in accounts payable, partially offset by an increase in inventory.

## Operating Earnings (Loss)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
<b>Earnings (Loss) From Continuing Operations, Before Income Tax</b>	<b>239</b>	(507)	<b>1,314</b>	(1,969)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss <sup>(2)</sup>	9	(247)	157	(508)
Non-Operating Unrealized Foreign Exchange (Gain) Loss <sup>(3)</sup>	87	(172)	(529)	297
(Gain) Loss on Divestiture of Assets	3	795	7	794
<b>Operating Earnings (Loss) From Continuing Operations, Before Income Tax</b>	<b>338</b>	(131)	<b>949</b>	(1,386)
Income Tax Expense (Recovery)	54	(90)	329	(301)
<b>Operating Earnings (Loss) From Continuing Operations</b>	<b>284</b>	(41)	<b>620</b>	(1,085)
Operating Earnings (Loss) From Discontinued Operations	-	(1)	-	28
<b>Total Operating Earnings (Loss)</b>	<b>284</b>	(42)	<b>620</b>	(1,057)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.

(3) 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 (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, 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.

Operating Earnings from continuing operations increased in the third quarter of 2019 compared with 2018 primarily due to a \$630 million provision for onerous contracts recorded in 2018, partially offset by lower Cash from Operating Activities and Adjusted Funds Flow, as discussed above, a re-measurement gain of \$17 million on the contingent payment compared with a gain of \$83 million in 2018, and higher depreciation, depletion and amortization ("DD&A").

On a year-to-date basis, Operating Earnings from continuing operations increased relative to 2018 primarily due to higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above, the 2018 provision for onerous contracts of \$692 million, a re-measurement loss of \$137 million on the contingent payment compared with a loss of \$411 million in 2018, and lower DD&A. The increase in our Operating Earnings for the nine months ended September 30, 2019 was partially offset by realized foreign exchange losses of \$279 million on the repurchase of our unsecured notes, compared with losses of \$20 million in 2018.

## Net Earnings (Loss)

(\$ millions)	Three Months Ended	Nine Months Ended
<b>Net Earnings (Loss) From Continuing Operations, for the Periods Ended September 30, 2018 <sup>(1)</sup></b>	<b>(242)</b>	<b>(1,566)</b>
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	(111)	1,337
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	(256)	(665)
Unrealized Foreign Exchange Gain (Loss)	(284)	859
Re-measurement of Contingent Payment	(66)	274
Gain (Loss) on Divestiture of Assets	792	787
Expenses <sup>(2)</sup>	689	628
DD&A	(19)	65
Exploration Expense	1	(2)
Income Tax Recovery (Expense)	(317)	364
<b>Net Earnings (Loss) From Continuing Operations, for the Periods Ended September 30, 2019</b>	<b>187</b>	<b>2,081</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, onerous contract provisions, 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 of \$187 million from continuing operations in the third quarter of 2019 increased compared with 2018 primarily due to a before-tax loss of \$795 million (\$526 million after-tax) on the divestiture of CPP in 2018 and higher Operating Earnings, as discussed above.

These increases to our Net Earnings from continuing operations were partially offset by:

- A deferred income tax expense of \$46 million compared with a deferred tax recovery of \$255 million in 2018;
- Non-operating foreign exchange losses of \$87 million compared with gains of \$172 million in 2018; and
- Unrealized risk management losses of \$9 million compared with unrealized gains of \$247 million in 2018.

On a year-to-date basis, Net Earnings of \$2,081 million from continuing operations increased from 2018 due to higher Operating Earnings, as discussed above, non-operating foreign exchange gains of \$529 million compared with losses of \$297 million in 2018, the loss on the CPP divestiture in 2018, and a deferred income tax recovery of \$790 million compared with a recovery of \$304 million in 2018. In 2019, we recorded a deferred income tax recovery of \$663 million associated with the reduction in the Alberta corporate tax rate and a recovery of \$387 million due to a step-up in the tax basis of our refining assets. These increases to our Net Earnings were partially offset by unrealized risk management losses of \$157 million compared with gains of \$508 million in 2018.

For the three months ended September 30, 2018, Net Earnings from discontinued operations was \$1 million. Net Earnings from discontinued operations for the nine months ended September 30, 2018 was \$253 million and included an after-tax gain of \$225 million on the divestiture of the Suffield assets in the first quarter of 2018.

## Total Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Oil Sands	152	176	502	718
Deep Basin	14	22	36	193
Refining and Marketing	87	59	214	147
Corporate and Eliminations	41	14	107	29
<b>Capital Investment – Continuing Operations</b>	<b>294</b>	<b>271</b>	<b>859</b>	<b>1,087</b>
Conventional (Discontinued Operations)	-	-	-	-
<b>Total Capital Investment <sup>(2)</sup></b>	<b>294</b>	<b>271</b>	<b>859</b>	<b>1,087</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A.

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

Capital investment in 2019 has been primarily focused on sustaining and maintenance capital for our existing business with minimal capital allocated to growth. Capital investment increased in the third quarter of 2019 compared with 2018, reflecting an increase in rail initiatives and corporate infrastructure programs. For the nine months ended September 30, 2019, capital investment decreased compared with 2018, reflecting our reduced capital investment program, lower Christina Lake phase G spend, as the project was completed in March 2019, and a smaller sustaining well program. Capital spending in the Oil Sands segment focused on sustaining capital related to existing production and stratigraphic test wells to determine pad placement for sustaining wells. Capital investment in the Deep Basin focused spending on pad and well equipping and tie-ins, as well as capital maintenance activities.

Refining and Marketing capital investment increased on a year-to-date basis due to higher spending on yield enhancements and capital maintenance projects, as well as higher spending on strategic rail initiatives and infrastructure.

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

## Capital Investment Decisions

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria based on a US\$45.00 per barrel WTI price and US\$13.00 per barrel WTI-WCS differential at Hardisty environment, which we believe are the bottom-of-the-cycle commodity prices, with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach helps position us to be financially resilient in times of lower cash flows. Balance sheet strength will continue to be a top priority and we plan to direct the majority of our Free Funds Flow towards debt reduction until we reach our longer-term Net Debt target of \$5.0 billion. This level of Net Debt approximates a Net Debt to EBITDA ratio of two times at bottom-of-the-cycle commodity prices. As we progress towards our longer-term Net Debt target, we will also consider opportunities for shareholder returns in the form of dividend increases and share repurchases.

Our capital allocation priorities include committed capital priorities and discretionary capital priorities. Committed capital priorities include safe and reliable operations, sustaining and maintenance capital for our existing business operations, funding our base dividend, and funding our targeted five to 10 percent dividend growth.

Discretionary capital allocation priorities, as we continue to reduce our Net Debt are:

- First, to continue to deleverage and reach our Net Debt target;
- Second, to support the potential sale of ConocoPhillips's ownership of Cenovus's common shares; and
- Third, balance other opportunistic share repurchases with disciplined investment in growing our business, while continuing to strengthen our balance sheet.

Refer to the Liquidity and Capital Resources section of this MD&A for further information.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Adjusted Funds Flow <sup>(2)</sup>	916	977	3,046	1,710
Total Capital Investment <sup>(2)</sup>	294	271	859	1,087
Free Funds Flow <sup>(2) (3)</sup>	622	706	2,187	623
Cash Dividends	60	61	183	183
	<b>562</b>	<b>645</b>	<b>2,004</b>	<b>440</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Includes our Conventional segment, which has been classified as a discontinued operation.

(3) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. We expect our capital investment and cash dividends for 2019 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 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.

**Deep Basin**, which includes approximately 2.8 million net acres of land primarily in the Elsworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities.

**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, transloading services provided to the Oil Sands segment by the Company's rail terminal, 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.

As at January 5, 2018, all 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 September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018	2019	2018
Oil Sands	2,386	2,717	7,352	8,134
Deep Basin	135	203	481	652
Refining and Marketing	2,420	3,126	7,958	8,135
Corporate and Eliminations	(205)	(189)	(448)	(622)
	<u>4,736</u>	<u>5,857</u>	<u>15,343</u>	<u>16,299</u>

## OIL SANDS

In the third quarter of 2019 we:

- Managed total production to mandated curtailment requirements;
- Generated Operating Margin of \$917 million, an increase of \$235 million due to higher average realized sales prices, decreased transportation and blending costs, and realized risk management gains of \$7 million compared with losses of \$323 million in 2018, partially offset by lower sales volumes and higher royalties;
- Earned crude oil Netbacks of \$27.82 per barrel, excluding realized risk management activities;
- Sold approximately one third of our Oil Sands production at sales locations outside of Alberta; and
- Used our fleet of leased railcars to sell 62,789 barrels per day at sales locations outside of Alberta, allowing us to capture higher market prices.

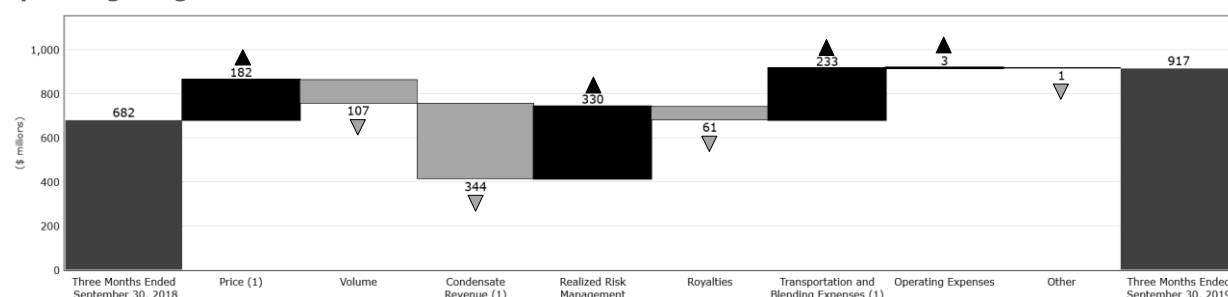
## Three Months Ended September 30, 2019 Compared With September 30, 2018

### Financial Results

	Three Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>
<b>Gross Sales</b>	<b>2,722</b>	2,992
Less: Royalties	336	275
<b>Revenues</b>	<b>2,386</b>	2,717
<b>Expenses</b>		
Transportation and Blending	1,249	1,482
Operating	227	230
(Gain) Loss on Risk Management	(7)	323
<b>Operating Margin</b>	<b>917</b>	682
Capital Investment	152	176
<b>Operating Margin Net of Related Capital Investment</b>	<b>765</b>	506

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

### 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 third quarter of 2019, our average realized crude oil sales price increased to \$54.94 per barrel (2018 – \$49.38 per barrel). While WTI decreased US\$13.05 per barrel to US\$56.45 per barrel, the WTI-WCS differential narrowed US\$10.01 per barrel to a discount of US\$12.24 per barrel (2018 – US\$22.25 per barrel) and the WCS-Christina Dilbit Blend ("CDB") differential narrowed to a discount of US\$2.00 per barrel (2018 – discount of US\$2.92 per barrel). In the three months ended September 30, 2019, we sold approximately one third of our production at sales locations outside of Alberta, contributing to the increase in our realized sales price.

Our realized 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 decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets and deliver it to the Edmonton hub. 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 sell our blended production. In a rising crude oil price environment, we expect to see a positive impact on our bitumen sales price as we are using condensate purchased at a lower price earlier in the year. The WCS-Condensate premium decreased US\$11.76 per barrel to a premium of US\$7.81 per barrel (2018 – premium of US\$19.57 per barrel), further increasing our average realized crude oil sales price.

#### Production Volumes

	Three Months Ended September 30,		
(barrels per day)	2019	Percent Change	2018
Foster Creek	156,527	(5)	163,939
Christina Lake	198,068	(7)	212,733
	<b>354,595</b>	<b>(6)</b>	<b>376,672</b>

Oil Sands production levels in the third quarter of 2019 decreased at both facilities compared with the same period in 2018, as a result of the government curtailment program restrictions.

### *Condensate*

The bitumen we produce must be blended with condensate to reduce its thickness to transport it to market through pipelines or by rail. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential in the third quarter of 2019, the proportion of the cost of condensate recovered increased. The total amount of condensate used decreased as a result of lower sales volumes.

### *Royalties*

Foster Creek and Christina Lake are post-payout projects for determining royalties. Our Christina Lake property achieved payout in the third quarter of 2018.

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.

Royalties for 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.

Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. Royalties for 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 revenues less diluent costs and transportation costs. Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

#### Effective Royalty Rates

(percent)	Three Months Ended September 30,	
	2019	2018
Foster Creek	21.8	24.9
Christina Lake	24.2	11.4

Royalties increased \$61 million in the third quarter of 2019 compared with 2018 due to Christina Lake achieving project payout in August 2018 and higher realized crude oil sales prices, partially offset by lower annual average WTI benchmark pricing (which determines the royalty rate). In 2019, our royalties were calculated on a net profit basis.

### **Expenses**

#### *Transportation and Blending*

Transportation and blending costs decreased \$233 million from the third quarter of 2018. Blending costs decreased primarily due to lower priced condensate in the third quarter of 2019 compared with 2018 and reduced condensate volumes required for our decreased production.

Transportation costs increased primarily due to higher rail costs and higher pipeline tariffs from increased volumes sold at U.S. destinations. In the three months ended September 30, 2019, approximately one third of our production was sold at locations outside of Alberta, of which 62,789 barrels per day were moved by rail (2018 – nil).

#### Per-unit Transportation Expenses

At Foster Creek, transportation costs increased to \$13.18 per barrel due to a higher proportion of our sales transported by rail and higher pipeline tariffs from increased U.S. sales, and decreased total sales volumes. Christina Lake transportation costs of \$7.20 per barrel were higher relative to 2018 due to a higher proportion of our production transported by rail to the U.S. and decreased total sales volumes, partially offset by lower pipeline tariffs. Transporting our volumes to U.S. destinations, either by pipeline or rail, allows us to achieve better market prices.

#### *Operating*

Primary drivers of our operating expenses in the third quarter of 2019 were workforce, fuel, chemical costs, and repairs and maintenance. Total operating expenses decreased \$3 million primarily due to lower fuel costs as a result of lower natural gas prices, and lower chemical costs, partially offset by higher greenhouse gas costs, higher workforce costs, and higher repairs and maintenance.

## Per-unit Operating Expenses

(\$/bbl)	Three Months Ended September 30,		
	2019	Percent Change	2018 <sup>(1)</sup>
<b>Foster Creek</b>			
Fuel	1.64	2	1.60
Non-fuel	6.36	8	5.88
Total	8.00	7	7.48
<b>Christina Lake</b>			
Fuel	1.21	(16)	1.44
Non-fuel	4.75	7	4.42
Total	5.96	2	5.86
<b>Total</b>	<b>6.90</b>	<b>5</b>	<b>6.59</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

At Foster Creek, per barrel fuel costs increased marginally in the third quarter of 2019 primarily due to lower sales volumes, partially offset by lower natural gas prices and lower fuel consumption. Foster Creek per-barrel non-fuel operating expenses increased compared with 2018, due to lower sales volumes, higher greenhouse gas costs, higher workforce costs and higher repairs and maintenance, partially offset by lower chemical costs.

At Christina Lake, per barrel fuel costs decreased due to less diluent burned as fuel and lower natural gas prices, partially offset by lower sales volumes and higher fuel consumption. At Christina Lake, per-barrel non-fuel operating expenses increased compared with 2018, due to lower sales volumes, higher workforce costs, partially offset by lower chemical costs due to lower production.

## Netbacks <sup>(1)</sup>

(\$/bbl)	Foster Creek		Christina Lake	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2019	2018 <sup>(2)</sup>	2019	2018 <sup>(2)</sup>
Sales Price	58.89	53.35	51.62	46.07
Royalties	9.90	11.81	10.62	4.64
Transportation and Blending	13.18	6.63	7.20	5.70
Operating Expenses	8.00	7.48	5.96	5.86
<b>Netback Excluding Realized Risk Management</b>	<b>27.81</b>	<b>27.43</b>	<b>27.84</b>	<b>29.87</b>
Realized Risk Management Gain (Loss)	0.13	(8.46)	0.27	(9.94)
<b>Netback Including Realized Risk Management</b>	<b>27.94</b>	<b>18.97</b>	<b>28.11</b>	<b>19.93</b>

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Risk Management

Risk management positions in the third quarter of 2019 resulted in realized gains of \$7 million (2018 – realized losses of \$323 million), consistent with our contract prices exceeding average benchmark prices.

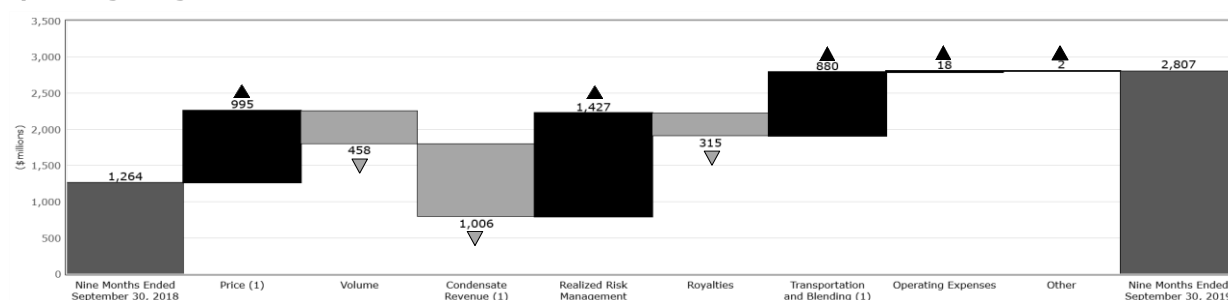
## Nine Months Ended September 30, 2019 Compared With September 30, 2018

### Financial Results

(\$ millions)	Nine Months Ended September 30,	
	2019	2018 <sup>(1)</sup>
<b>Gross Sales</b>	<b>8,179</b>	<b>8,646</b>
Less: Royalties	827	512
<b>Revenues</b>	<b>7,352</b>	<b>8,134</b>
<b>Expenses</b>		
Transportation and Blending	3,736	4,616
Operating	771	789
(Gain) Loss on Risk Management	38	1,465
<b>Operating Margin</b>	<b>2,807</b>	<b>1,264</b>
Capital Investment	502	718
<b>Operating Margin Net of Related Capital Investment</b>	<b>2,305</b>	<b>546</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## 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 nine months ended September 30, 2019, our realized crude oil sales price increased to \$55.82 per barrel compared with \$45.15 per barrel in 2018. The increase in our crude oil price reflects the narrower WCS-Condensate premium of US\$7.49 per barrel (2018 – premium of US\$21.41 per barrel) and narrower WCS-CDB differential, and a rise in WCS prices. In the nine months ended September 30, 2019, we sold approximately one quarter of our production at sales locations outside of Alberta, contributing to the increase in our realized sales prices.

### Production Volumes

(barrels per day)	Nine Months Ended September 30,		
	2019	Percent Change	2018
Foster Creek	158,888	(3)	164,160
Christina Lake	188,671	(11)	211,141
	<b>347,559</b>	<b>(7)</b>	<b>375,301</b>

Production at Foster Creek and Christina Lake was lower compared with 2018 primarily due to the mandated production curtailments. In addition, the planned turnaround at Christina Lake in the second quarter of 2019 reduced production by approximately 2,555 barrels per day in 2019; however, the impact was minimized by using the Christina Lake phase G facility and production capabilities from Foster Creek.

### Royalties

#### Effective Royalty Rates

(percent)	Nine Months Ended September 30,	
	2019	2018
Foster Creek	17.4	19.5
Christina Lake	20.6	6.4

On a year-to-date basis, royalties increased \$315 million compared with 2018. Royalties increased due to Christina Lake achieving project payout in August 2018 and higher realized sales prices, partially offset by lower annual average WTI benchmark pricing (which determines the royalty rate).

## Expenses

### Transportation and Blending

Transportation and blending costs decreased \$880 million. Blending costs decreased due to lower condensate prices and a decline in condensate volumes required for our lower production. 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 an increase in volumes shipped by rail and higher pipeline tariff costs from increased U.S. sales. In 2019, using our railcars we sold 33,892 barrels per day of our production to locations outside of Alberta (2018 – nil). Transporting our volumes to U.S. destinations, either by pipeline or rail, allows us to achieve better market prices.

## Per-unit Transportation Expenses

Foster Creek and Christina Lake per-unit transportation costs increased \$3.09 per barrel and \$1.01 per barrel, respectively, as a result of higher sales volumes shipped by rail to the U.S. and decreased total sales volumes relative to 2018.

## Operating

Primary drivers of our operating expenses in 2019 were workforce, fuel, repairs and maintenance, and chemical costs. Total operating costs decreased \$18 million, while per-barrel operating expenses increased primarily due to lower sales volumes.

## Per-unit Operating Expenses

	Nine Months Ended September 30,		
(\$/bbl)	2019	Percent Change	2018
<b>Foster Creek</b>			
Fuel	2.30	11	2.08
Non-fuel	6.78	-	6.80
Total	9.08	2	8.88
<b>Christina Lake</b>			
Fuel	1.90	3	1.84
Non-fuel	5.50	19	4.63
Total	7.40	14	6.47
<b>Total</b>	<b>8.18</b>	<b>8</b>	<b>7.54</b>

At both Foster Creek and Christina Lake, per-barrel fuel costs increased due to lower sales volumes and higher natural gas prices and fuel consumption. We continue to maintain steam production levels at pre-curtailement levels. Per-barrel non-fuel operating expenses at Foster Creek was relatively flat in 2019 compared with 2018 due to lower chemical costs, less workovers and lower workforce costs offset by lower sales volumes. Per-barrel non-fuel operating expenses at Christina Lake increased in 2019 primarily due to lower sales volumes, increased repairs and maintenance, waste, fluid handling and trucking costs due to the planned turnaround in the second quarter, partially offset by lower chemical costs due to a volume related decrease in sulphur treating.

## Netbacks <sup>(1)</sup>

	Foster Creek		Christina Lake	
	Nine Months Ended September 30,			
(\$/bbl)	2019	2018 <sup>(2)</sup>	2019	2018 <sup>(2)</sup>
Sales Price	59.04	49.10	53.02	41.97
Royalties	8.19	8.15	9.44	2.37
Transportation and Blending	10.76	7.67	6.16	5.15
Operating Expenses	9.08	8.88	7.40	6.47
Netback Excluding Realized Risk Management	31.01	24.40	30.02	27.98
Realized Risk Management Gain (Loss)	(0.35)	(13.82)	(0.45)	(14.43)
Netback Including Realized Risk Management	30.66	10.58	29.57	13.55

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Risk Management

Risk management positions in 2019 resulted in realized losses of \$38 million (2018 – realized losses of \$1,465 million), consistent with average benchmark prices exceeding our contract prices on hedging contracts.

## Oil Sands – Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Foster Creek	46	80	169	327
Christina Lake	84	81	279	356
	130	161	448	683
Other <sup>(2)</sup>	22	15	54	35
<b>Capital Investment <sup>(3)</sup></b>	<b>152</b>	<b>176</b>	<b>502</b>	<b>718</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

(2) Includes new resource plays, Narrows Lake, Telephone Lake and Athabasca natural gas.

(3) Includes expenditures on PP&E and E&E assets.

In the nine months ended September 30, 2019, Oil Sands capital investment of \$502 million focused on a smaller sustaining well program than in 2018, stratigraphic test wells and the completion of Christina Lake phase G construction. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells. Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells, and the completion of the phase G construction in March. Christina Lake capital increased in the third quarter of 2019 compared with 2018 due to higher capital investment on completions, partially offset by lower spend on Christina Lake phase G.

## Drilling Activity

	Gross Stratigraphic Test Wells		Gross Production Wells <sup>(1)</sup>	
Nine Months Ended September 30,	2019	2018	2019	2018
Foster Creek	14	43	-	14
Christina Lake	18	63	11	29
	32	106	11	43
Other	14	21	2	-
	46	127	13	43

(1) Steam-assisted gravity drainage 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

We updated our 2019 guidance estimates to reflect our continued focus on capital discipline and efficiencies identified within our Oil Sands capital programs. Guidance decreased from our 2019 estimates released on April 23, 2019. Our revised full year 2019 Oil Sands capital investment is forecast to be between \$665 million and \$720 million. Updated guidance dated October 1, 2019 is available on our website at [cenovus.com](http://cenovus.com).

Foster Creek capital investment for 2019 is forecast to be between \$230 million and \$250 million. We plan to continue focusing on sustaining capital related to existing production.

Christina Lake capital investment for 2019 is forecast to be between \$350 million and \$370 million focused on sustaining capital. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, was completed at the end of the first quarter of 2019. We have flexibility on when we ramp up production from Christina Lake phase G. We will take into consideration whether mandated production curtailments have been lifted and if there is sustained improvement in market access and heavy oil benchmark prices before we ramp up phase G.

In 2019, we plan to spend a minimal amount of capital on Foster Creek phase H, Christina Lake phase H and Narrows Lake to continue to advance each opportunity to sanction-ready status.

In 2019, our Technology and other capital investment, forecast to be between \$70 million and \$80 million, relates to the development of Marten Hills as well as advancing key strategic initiatives that are expected to provide both cost and environmental benefits. This includes ongoing work on solvents, partial upgrading and advancing our new oil sands facility design.

## 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 estimated 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.

We depreciate our right-of-use ("ROU") assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

Amounts related to assets under construction and assets held for sale are not depleted. Further information on our accounting policy for DD&A is included in our notes to the December 31, 2018 Consolidated Financial Statements and the interim Consolidated Financial Statements.

In the three and nine months ended September 30, 2019, Oil Sands DD&A was \$391 million and \$1,127 million, respectively. Oil Sands DD&A increased compared with 2018 due to an increase in our average depletion rate, partially offset by lower sales volumes and additional depreciation expense on our ROU assets. Our depletion rate increased as a result of higher future development costs due to additional capital required to improve recovery performance and develop thin pay volumes at Christina Lake and Foster Creek, as well as an increase in maintenance capital at Foster Creek. The average depletion rate for the three and nine months ended September 30, 2019 was approximately \$11.15 per BOE (2018 – \$10.61 per BOE).

Exploration expense of \$1 million and \$10 million was recorded in the three and nine months ended September 30, 2019, respectively (2018 – \$2 million and \$8 million, respectively).

## DEEP BASIN

In the third quarter of 2019 we:

- Produced a total of 93,901 BOE per day compared with 118,920 BOE per day in 2018;
- Generated Operating Margin of \$37 million;
- Earned a Netback of \$3.73 per BOE, excluding realized risk management activities compared with \$6.73 per BOE, excluding realized risk management activities in 2018; and
- Realized lower operating expenses by optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure to lower the cost structure.

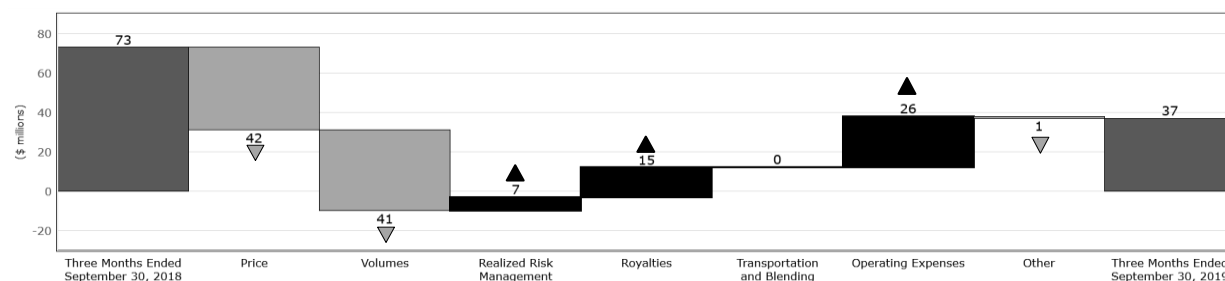
## Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
<b>Gross Sales</b>	<b>131</b>	214	<b>501</b>	714
Less: Royalties	<b>(4)</b>	11	<b>20</b>	62
<b>Revenues</b>	<b>135</b>	203	<b>481</b>	652
<b>Expenses</b>				
Transportation and Blending	<b>20</b>	20	<b>62</b>	72
Operating	<b>77</b>	103	<b>257</b>	303
Production and Mineral Taxes	<b>1</b>	-	<b>1</b>	1
(Gain) Loss on Risk Management	<b>-</b>	7	<b>-</b>	26
<b>Operating Margin</b>	<b>37</b>	73	<b>161</b>	250
Capital Investment	<b>14</b>	22	<b>36</b>	193
<b>Operating Margin Net of Related Capital Investment</b>	<b>23</b>	51	<b>125</b>	57

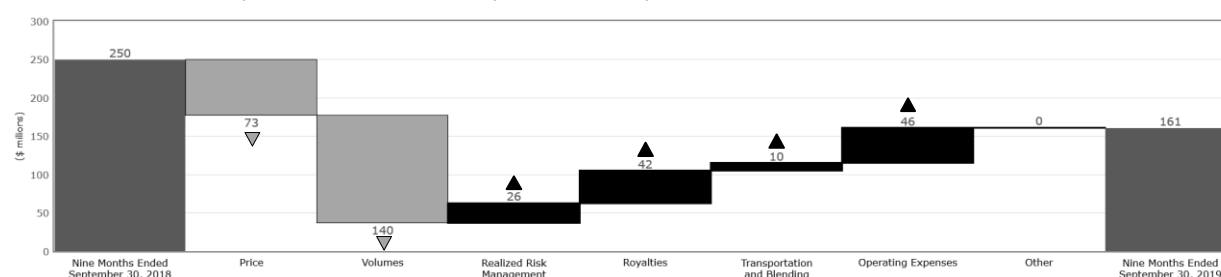
(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Operating Margin Variance

Three Months Ended September 30, 2019 Compared With September 30, 2018



*Nine Months Ended September 30, 2019 Compared With September 30, 2018*



## Revenues

### Price

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Light and Medium Oil (\$/bbl)	68.53	73.00	66.08	73.37
NGLs (\$/bbl)	22.16	41.40	26.08	40.44
Natural Gas (\$/mcf)	1.21	1.31	1.82	1.62
<b>Total Oil Equivalent (\$/BOE)</b>	<b>13.84</b>	<b>18.45</b>	<b>17.03</b>	<b>19.69</b>

For the three and nine months ended September 30, 2019, revenues included \$12 million and \$42 million, respectively, of processing fee revenue related to our interests in natural gas processing facilities (2018 – \$12 million and \$42 million, respectively). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks. Revenues decreased for the three and nine months ended September 30, 2019 compared with 2018 due to lower volumes and lower prices.

### Production Volumes

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
<b>Liquids</b>				
Crude Oil (barrels per day)	4,929	5,674	4,885	6,148
NGLs (barrels per day)	21,175	26,595	21,950	27,770
	26,104	32,269	26,835	33,918
<b>Natural Gas (MMcf per day)</b>	<b>407</b>	<b>520</b>	<b>432</b>	<b>546</b>
<b>Total Production (BOE/d)</b>	<b>93,901</b>	<b>118,920</b>	<b>98,807</b>	<b>124,984</b>
Natural Gas Production (percentage of total)	72	73	73	73
Liquids Production (percentage of total)	28	27	27	27

Production for the three and nine months ended September 30, 2019 declined from 2018 due to natural declines from the lower capital investment, the divestiture of CPP and temporary well shut-ins resulting from low gas prices. CPP was sold on September 6, 2018 and produced approximately 6,990 BOE per day and 8,720 BOE per day for the three and nine month periods ended September 30, 2018, respectively. The temporary shut-in of wells reduced production by approximately 4,990 BOE per day in the third quarter of 2019.

### Royalties

For the three months ended September 30, 2019, the effective royalty rates for liquids and natural gas were negative 3.3 percent and negative 3.8 percent, respectively (2018 – 9.5 percent and negative 4.7 percent, respectively) due to the natural gas liquids and gas cost allowance royalty credit being higher than the royalty expenses as a result of low prices and volumes. On a year-to-date basis, the effective royalty rates for liquids and natural gas were 8.6 percent and 0.7 percent, respectively (2018 – 14.2 percent and 1.9 percent, respectively) due to declines in price and production.

## Expenses

### Transportation

Per unit transportation costs increased compared with 2018 due to lower volumes and increased pipeline tariffs. 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 fees, property taxes, and electrical costs. Operating costs averaged \$8.21 per BOE and \$8.83 per BOE in the three and nine months ended September 30, 2019, respectively (2018 – \$8.89 per BOE and \$8.31 per BOE, respectively). The decrease in per-unit operating costs for the third quarter was driven by lower third-party processing fees resulting from lower throughput and leveraging our infrastructure to reduce fees, lower repairs and maintenance activity, workforce costs, and electrical costs, partially offset by lower sales volumes. The increase in per-unit operating costs on a year-to-date basis were driven by lower sales volumes, partially offset by lower repairs and maintenance activity, third-party processing fees due to lower throughput and from leveraging our infrastructure to reduce fees paid, and workforce costs.

## Netbacks

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$/BOE)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Sales Price	13.84	18.45	17.03	19.69
Royalties	(0.41)	0.95	0.76	1.80
Transportation and Blending	2.28	1.85	2.29	1.99
Operating Expenses	8.21	8.89	8.83	8.31
Production and Mineral Taxes	0.03	0.03	0.03	0.03
<b>Netback Excluding Realized Risk Management</b>	<b>3.73</b>	6.73	<b>5.12</b>	7.56
Realized Risk Management Gain (Loss)	-	(0.66)	(0.01)	(0.77)
<b>Netback Including Realized Risk Management</b>	<b>3.73</b>	6.07	<b>5.11</b>	6.79

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Risk Management

Risk management activities in the three and nine months ended September 30, 2019 were minimal (2018 – realized losses of \$7 million and \$26 million, respectively).

## Deep Basin – Capital Investment

We invested \$14 million and \$36 million, in the three and nine months ended September 30, 2019, respectively, compared with \$22 million and \$193 million in the same periods of 2018. Capital investment focused on pad and well equipping and tie-ins, as well as capital maintenance activities. In 2018, we focused on facilities and infrastructure to support production in our core development areas.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018	2019	2018
Drilling and Completions	1	9	2	113
Facilities	6	2	13	47
Other	7	11	21	33
<b>Capital Investment <sup>(1)</sup></b>	<b>14</b>	22	<b>36</b>	193

(1) Includes expenditures on PP&E and E&E assets.

## Drilling Activity

In the third quarter of 2019, there were no wells drilled and on a year-to-date basis, there was one well tied-in. In the three months ended September 30, 2018, there were four wells completed and two wells tied-in. In the nine months ended September 30, 2018 there were 13 operated and two non-operated net horizontal wells drilled, 21 wells completed, and 22 wells tied-in.

## Future Capital Investment

Upon further review of our capital program, we have updated our 2019 guidance. Our Deep Basin capital investment is forecast to be between \$50 million and \$60 million in 2019. Guidance dated October 1, 2019 is available on our website at [cenovus.com](http://cenovus.com).

We continue to take a disciplined approach to the development of our Deep Basin assets considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. Management is committed to developing this significant resource; however, at a pace of development that reflects the prevailing commodity price environment.

## 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 \$8.90 per BOE and \$9.10 per BOE for the three and nine months ended September 30, 2019, respectively (2018 – \$9.82 per BOE and \$10.18 per BOE, respectively).

For the three and nine months ended September 30, 2019, total Deep Basin DD&A was \$78 million and \$247 million, respectively (2018 – \$95 million and \$406 million, respectively). The decrease was due to the divestiture of CPP in the third quarter of 2018 and a lower depletion rate. On a year-to-date basis in 2018, DD&A included an impairment loss of \$100 million on the Clearwater cash-generating unit which was reversed at December 31, 2018.

## REFINING AND MARKETING

In the third quarter of 2019 we:

- Achieved crude oil runs averaging 465,000 barrels per day, a decrease compared with the third quarter of 2018;
- Generated Operating Margin of \$126 million, a decrease of \$310 million compared with 2018 due to lower crude advantage, market crack spreads, and crude oil runs and higher operating costs; and
- Attained a record monthly crude oil run rate in July at Wood River; and
- Increased rail volumes loaded at the Bruderheim crude-by-rail terminal, averaging 64,773 barrels per day compared with 43,018 barrels per day in the third quarter of 2018.

### Refinery Operations <sup>(1)</sup>

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
<b>Crude Oil Capacity</b> (Mbbbls/d)	<b>482</b>	460	<b>482</b>	460
<b>Crude Oil Runs</b> (Mbbbls/d)	<b>465</b>	492	<b>438</b>	436
Heavy Crude Oil	<b>185</b>	204	<b>174</b>	190
Light/Medium	<b>280</b>	288	<b>264</b>	246
<b>Refined Products</b> (Mbbbls/d)	<b>485</b>	518	<b>463</b>	459
Gasoline	<b>215</b>	251	<b>218</b>	225
Distillate	<b>169</b>	170	<b>162</b>	169
Other	<b>101</b>	97	<b>83</b>	65
<b>Crude Utilization</b> (percent)	<b>96</b>	107	<b>91</b>	95

(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 total processing capacity was re-rated on January 1, 2019 to 482,000 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 both WCS and WTS 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.

For the three months ended September 30, 2019, total crude oil runs and refined product output decreased compared with the third quarter of 2018 due to unplanned outages and the startup of planned turnaround activities at both Refineries in September 2019. This decrease was partially offset by Wood River achieving a record monthly crude oil run rate in July. On a year-to-date basis, crude oil runs and refined product output increased compared with the prior year, as planned turnarounds and unplanned outages at the Refineries in 2019, including a fire in a crude unit at Wood River in the first quarter of 2019, had less of an impact than major planned turnarounds completed at the Refineries in the first quarter of 2018.

### Crude-By-Rail Terminal

We continue to increase total rail volumes loaded at our Bruderheim crude-by-rail terminal. In the three months ended September 30, 2019, we loaded an average of 64,773 barrels per day at our Bruderheim crude-by-rail facility (45,154 barrels per day of our volumes) compared with an average of 43,018 barrels per day in the third quarter of 2018 (33,315 barrels per day of our volumes). On a year-to-date basis, we loaded an average of

57,092 barrels per day (34,400 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 27,092 barrels per day in 2018 (20,799 barrels per day of our volumes).

## Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Revenues	2,420	3,126	7,958	8,135
Purchased Product	2,042	2,483	6,646	6,664
<b>Gross Margin</b>	<b>378</b>	643	<b>1,312</b>	1,471
<b>Expenses</b>				
Operating	255	209	698	724
(Gain) Loss on Risk Management	(3)	(2)	(14)	2
<b>Operating Margin</b>	<b>126</b>	436	<b>628</b>	745
Capital Investment	87	59	214	147
<b>Operating Margin Net of Related Capital Investment</b>	<b>39</b>	377	<b>414</b>	598

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

### 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 months ended September 30, 2019, Refining and Marketing gross margin decreased \$265 million compared with the same period in 2018 due to lower crude advantage from narrowing heavy and medium sour crude oil differentials, lower market crack spreads associated with decreased global crude oil prices, and declines in crude oil runs due to unplanned outages and the startup of planned turnarounds at both Refineries. In the nine months ended September 30, 2019, Refining and Marketing gross margin decreased \$159 million. The decrease resulted from lower crude advantage from narrowing heavy and medium sour crude oil differentials, partially offset by higher margins on fixed priced products due to a lower benchmark WTI, and a reduction in the cost of RINs. Our gross margin was positively impacted by approximately \$4 million and \$39 million for the three and nine months ended September 30, 2019, respectively, due to the weakening of the Canadian dollar relative to the U.S. dollar.

In the three and nine months ended September 30, 2019, the cost of RINs was \$24 million and \$73 million, respectively (2018 – \$27 million and \$108 million, respectively). RIN costs declined, despite higher volume obligations in 2019, primarily due to the decrease in RINs benchmark prices as a result of small refiners being granted exemptions from volume obligations.

### Operating Expense

Primary drivers of operating expenses are maintenance, labour and utilities. Operating expenses increased in the third quarter of 2019 primarily due to higher maintenance costs associated with the startup of the planned turnarounds in September. Operating expenses decreased on a year-to-date basis primarily due to higher planned major turnaround costs in 2018.

### Refining and Marketing – Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
Wood River Refinery	41	33	96	91
Borger Refinery	25	26	82	54
Marketing	21	-	36	2
<b>Capital Investment</b>	<b>87</b>	59	<b>214</b>	147

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Capital expenditures in the three and nine months ended September 30, 2019 focused primarily on refined products yield enhancement projects, as well as strategic rail initiatives and infrastructure.

In 2019, we expect to invest between \$260 million and \$290 million and will continue to focus on capital maintenance, reliability work and yield improvement projects. Our guidance dated October 1, 2019 is available on our website at [cenovus.com](http://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 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. For the three and nine months ended September 30, 2019, Refining and Marketing DD&A was \$65 million and \$213 million, respectively (2018 – \$56 million and \$165 million, respectively). The increase is primarily attributable to depreciation of our ROU assets which commenced January 1, 2019 on the adoption of IFRS 16.

## CORPORATE AND ELIMINATIONS

In the three and nine months ended September 30, 2019, our risk management activities resulted in unrealized risk management losses of \$9 million (2018 – gains of \$247 million) and \$157 million (2018 – gains of \$508 million), respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2019	2018 <sup>(1)</sup>	2019	2018 <sup>(1)</sup>
General and Administrative	72	78	209	304
Onerous Contract Provisions	(1)	630	(8)	692
Finance Costs	138	183	376	489
Interest Income	(3)	(5)	(9)	(11)
Foreign Exchange (Gain) Loss, Net	88	(182)	(265)	307
Re-measurement of Contingent Payment	(17)	(83)	137	411
Research Costs	6	4	16	23
(Gain) Loss on Divestiture of Assets	3	795	7	794
Other (Income) Loss, Net	(11)	(11)	(4)	(11)
	<b>275</b>	<b>1,409</b>	<b>459</b>	<b>2,998</b>

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Expenses

### General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and office rent. General and administrative costs in the third quarter of 2019 are in line with the same period of 2018, driven by lower rent expense primarily due to the adoption of IFRS 16, partially offset by higher long-term employee incentive costs in 2019. On a year-to-date basis, general and administrative expenses decreased \$95 million due to lower rent expense of \$72 million primarily from the adoption of IFRS 16, lower headcount and minimal severance costs in 2019 compared with \$48 million of severance costs in 2018, partially offset by higher employee long-term incentive costs.

### Onerous Contract Provisions

In 2019, onerous contract provisions are composed of non-lease components of real estate contracts which consist of operating costs and unreserved parking. In 2018, onerous contract provisions included the lease components of base rent and reserved parking as well as the non-lease components.

In the three and nine months ended September 30, 2019, we recorded a non-cash recovery for onerous contracts of \$1 million and \$8 million, respectively, due to an update in the underlying assumptions associated with certain Calgary office space (2018 – expense of \$630 million and \$692 million, respectively).

### Finance Costs

Finance costs include interest expense on our short-term borrowings, long-term debt, and lease liabilities (commencing January 1, 2019), as well as the discount or premium on redemption of long-term debt and unwinding of the discount on decommissioning liabilities. Finance costs decreased by \$45 million in the three months ended September 30, 2019 compared with 2018 due to the significant reduction of total debt, partially offset by a \$20 million increase in interest related to lease liabilities from the adoption of IFRS 16. On a year-to-date basis, finance costs decreased by \$113 million compared with 2018 due to the significant reduction of total debt that resulted in decreased interest expense and a discount of \$64 million on the repurchase of unsecured notes in 2019, partially offset by an increase in interest of \$59 million related to lease liabilities from the adoption of IFRS 16.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2019 was 5.2 percent and 5.1 percent, respectively (2018 – 5.1 percent).

## Foreign Exchange

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Unrealized Foreign Exchange (Gain) Loss	<b>88</b>	(196)	<b>(560)</b>	299
Realized Foreign Exchange (Gain) Loss	-	14	<b>295</b>	8
	<b>88</b>	(182)	<b>(265)</b>	307

In the three and nine months ended September 30, 2019, unrealized foreign exchange losses of \$88 million and unrealized foreign exchange gains of \$560 million, respectively, were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at September 30, 2019 was weaker compared with June 30, 2019 and stronger compared with December 31, 2018. For the nine months ended September 30, 2019, realized foreign exchange losses of \$295 million were recorded primarily as a result of the recognition of foreign exchange losses from the repurchase of debt.

## Re-measurement of Contingent Payment

Related to our Oil Sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries ("ConocoPhillips") during the five years subsequent to the closing date of the acquisition of Deep Basin assets from ConocoPhillips in conjunction with their 50 percent interest in the FCCL Partnership on May 17, 2017 (the "Acquisition") for quarters in which the average WCS crude oil price exceeds \$52 per barrel during the quarter. The quarterly payment is \$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 \$130 million as at September 30, 2019 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 months ended September 30, 2019, a non-cash re-measurement gain of \$17 million was recorded and for the nine months ended September 30, 2019, we recorded a re-measurement loss of \$137 million.

Average WCS forward pricing for the remaining term of the contingent payment is \$42.75 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately \$38.30 per barrel and \$52.10 per barrel.

## Corporate – Capital Investment

Capital expenditures of \$107 million in the nine months ended September 30, 2019 focused primarily on the build-out of office space at Brookfield Place and information technology capital.

In 2019, we expect to invest between \$150 million and \$165 million, the majority of which is for the build-out of office space at Brookfield Place. Guidance dated October 1, 2019 is available on our website at cenovus.com.

## 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. ROU assets (real estate assets) are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in the third quarter of 2019 was \$24 million (2018 – \$14 million) and \$81 million on a year-to-date basis (2018 – \$43 million). The increase in DD&A compared with 2018 was due to additional depreciation expense on our ROU assets.

## Income Tax

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
Current Tax				
Canada	<b>10</b>	(15)	<b>22</b>	(108)
United States	<b>(4)</b>	5	<b>1</b>	9
<b>Current Tax Expense (Recovery)</b>	<b>6</b>	(10)	<b>23</b>	(99)
<b>Deferred Tax Expense (Recovery)</b>	<b>46</b>	(255)	<b>(790)</b>	(304)
<b>Total Tax Expense (Recovery) From Continuing Operations</b>	<b>52</b>	(265)	<b>(767)</b>	(403)

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.

A current tax expense of \$23 million was recorded for the nine months ended September 30, 2019 compared with a recovery in 2018 due to the carryback of losses to recover tax paid in previous years.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, we recorded a deferred income tax recovery of \$663 million for the nine months ended September 30, 2019. In addition, we have recorded a deferred income tax recovery of \$387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our refining assets.

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.

## DISCONTINUED OPERATIONS

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. After-tax earnings from discontinued operations for the nine months ended September 30, 2018 were \$28 million. An after-tax gain on discontinuance of \$225 million was recorded on the sale.

## LIQUIDITY AND CAPITAL RESOURCES

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
<b>Cash From (Used In)</b>				
Operating Activities – Continuing Operations	834	1,258	2,545	1,630
Operating Activities – Discontinued Operations	-	1	-	39
Total Operating Activities	834	1,259	2,545	1,669
Investing Activities – Continuing Operations	(343)	305	(966)	(649)
Investing Activities – Discontinued Operations	-	(5)	-	409
Total Investing Activities	(343)	300	(966)	(240)
<b>Net Cash Provided (Used) Before Financing Activities</b>	<b>491</b>	<b>1,559</b>	<b>1,579</b>	<b>1,429</b>
Financing Activities	(100)	(68)	(1,888)	(204)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	(18)	(2)	(35)	30
<b>Increase (Decrease) in Cash and Cash Equivalents</b>	<b>373</b>	<b>1,489</b>	<b>(344)</b>	<b>1,255</b>
As at				
<b>Cash and Cash Equivalents</b>			<b>September 30, 2019</b>	<b>December 31, 2018</b>
<b>Committed and Undrawn Credit Facility</b>			<b>4,500</b>	<b>4,500</b>

### Cash From (Used In) Operating Activities

In the three months ended September 30, 2019, cash generated by operating activities decreased mainly due to lower Operating Margin, as discussed in the Financial Results section of this MD&A and changes in non-cash working capital, as discussed in the Financial Results section of this MD&A. The decreases in cash from operating activities were partially offset by a decrease in finance costs, as discussed in the Corporate and Eliminations section of this MD&A.

In the nine months ended September 30, 2019, cash from operating activities increased mainly as a result of:

- Higher Operating Margin, as discussed in the Financial Results section of this MD&A;
- A decrease in general and administrative costs, due to a \$72 million decrease in rent expense primarily from the adoption of IFRS 16 and \$48 million of severance costs recognized in 2018; and
- A decrease in finance costs, as discussed in the Corporate and Eliminations section of this MD&A.

The increases in cash from operating activities for the nine months ended September 30, 2019 were partially offset by a current income tax expense in 2019 compared to a recovery in 2018 and changes in non-cash working capital, as discussed in the Financial Results section of this MD&A.

Excluding risk management assets and liabilities and the current portion of the contingent payment, our working capital was \$412 million at September 30, 2019 compared with \$450 million at December 31, 2018.

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

### **Cash From (Used In) Investing Activities**

In the third quarter of 2019, cash used in investing activities was higher compared with the third quarter of 2018 due to increased capital investment and changes in non-cash working capital. In 2018, we received proceeds of \$625 million on the divestiture of CPP.

On a year-to-date basis, cash used in investing activities was higher in 2019 compared with 2018 primarily due to proceeds from the divestiture of CPP and the Suffield assets in 2018 and changes in non-cash working capital.

### **Cash From (Used In) Financing Activities**

During the nine months ended September 30, 2019, we repaid US\$1.3 billion of unsecured notes for cash consideration of US\$1.2 billion (\$1.6 billion). Total debt as at September 30, 2019 was \$7,239 million (December 31, 2018 – \$9,164 million). Subsequent to September 30, 2019 we repaid in full the maturing 5.70 percent unsecured notes with a remaining principal amount of US\$500 million and repurchased a further US\$13 million of our 4.45 percent unsecured notes due September 15, 2042 for cash of US\$13 million.

As at September 30, 2019, we were in compliance with all of the terms of our debt agreements.

### **Dividends**

In the three and nine months ended September 30, 2019, we paid dividends of \$0.05 per common share or \$60 million and \$0.15 per common share or \$183 million, respectively (2018 – \$0.05 per common share or \$61 million and \$0.15 per common share or \$183 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. On October 2, 2019, we announced a 25 percent dividend increase to \$0.0625 per share for the fourth quarter of 2019, payable on December 31, 2019, to common shareholders of record as at December 13, 2019.

### **Available Sources of Liquidity**

We expect cash flows from our upstream and refining operations to fund all of our cash requirements in 2019. 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. Subsequent to September 30, 2019, Moody's Investors Service ("Moody's") changed their outlook on our Ba1 rating to positive from stable. In addition to making progress towards re-establishing an investment grade credit rating at Moody's 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 September 30, 2019:

(\$ millions)	Term	Amount
Cash and Cash Equivalents	<b>Not applicable</b>	<b>437</b>
Committed Credit Facility – Tranche A <sup>(1)</sup>	<b>November 2022</b>	<b>3,300</b>
Committed Credit Facility – Tranche B <sup>(2)</sup>	<b>November 2021</b>	<b>1,200</b>

(1) Extended to November 30, 2023, effective October 23, 2019.

(2) Extended to November 30, 2022, effective October 23, 2019.

### **Committed Credit Facility**

We have a committed credit facility in place that consists of a \$1.2 billion tranche and a \$3.3 billion tranche. Effective October 23, 2019, we amended the committed credit facility to extend the maturity date of the \$1.2 billion tranche to November 30, 2022 and the maturity date of the \$3.3 billion tranche to November 30, 2023. As of September 30, 2019, no amounts were drawn on our committed credit facility.

### **Base Shelf Prospectus**

On September 19, 2019, we filed a base shelf prospectus that allows us to offer, from time to time, up to US\$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere, where permitted by law. ConocoPhillips may also offer and sell, should they so choose from time to time, the common shares they acquired in connection with the Acquisition. The base shelf prospectus will expire in October 2021 and replaces our US\$7.5 billion base shelf prospectus, which would have expired in November 2019. 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, E&E Write-down, 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 twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at	September 30, 2019	December 31, 2018
Net Debt to Capitalization (percent)	26	32
Net Debt to Adjusted EBITDA <sup>(1)</sup>	1.9x	5.9x

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Over the long-term, Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. At different points within the economic cycle, we expect this ratio may periodically be above the target. 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. We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreement.

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.

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 September 30, 2019, there were approximately 1,229 million common shares outstanding (2018 – 1,229 million common shares).

Refer to Note 23 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 September 30, 2019	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares <sup>(1)</sup>	1,228,828	N/A
Stock Options	31,823	24,058
Other Stock-Based Compensation Plans	17,104	1,506

(1) ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Acquisition.

### Contractual Obligations and Commitments

Cenovus has obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, 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 interim Consolidated Financial Statements and December 31, 2018 Consolidated Financial Statements.

On January 1, 2019, the Company adopted IFRS 16, which resulted in the recognition of lease liabilities related to operating leases on the balance sheet. These liabilities were previously reported as commitments. For a reconciliation of our commitments as at December 31, 2018 to our lease liabilities as at January 1, 2019, see Note 3 to the interim Consolidated Financial Statements.

As at September 30, 2019, total commitments were \$23 billion, of which \$22 billion are for various transportation and storage commitments. Transportation commitments include \$13 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2018 – \$14 billion). Terms are up to 20 years subsequent to the date of commencement and should help align the Company's future transportation requirements with anticipated production growth. Transportation and storage commitments include future commitments of \$131 million relating to railcar leases and \$195 million for storage tank leases that have not yet commenced. The railcar leases are expected to commence in 2019 and 2020 with lease terms between five and ten years and the storage tank leases are expected to commence in 2019 and 2020 with lease terms of three and ten years.

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 September 30, 2019, there were outstanding letters of credit aggregating \$367 million issued as security for performance under certain contracts (December 31, 2018 – \$336 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 interim Consolidated Financial Statements.

## Contingent Payment

In connection with the Acquisition and related to our 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 September 30, 2019, the estimated fair value of the contingent payment was \$130 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 2018 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 24 and 25 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

(\$ millions)	Three Months Ended September 30,					
	2019			2018		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	(7)	9	2	330	(237)	93
Refining	(3)	-	(3)	(2)	5	3
Interest Rate	-	-	-	-	(15)	(15)
Foreign Exchange	1	-	1	(3)	-	(3)
<b>(Gain) Loss on Risk Management</b>	<b>(9)</b>	<b>9</b>	<b>-</b>	<b>325</b>	<b>(247)</b>	<b>78</b>
Income Tax Expense (Recovery)	2	(1)	1	(87)	65	(22)
<b>(Gain) Loss on Risk Management, After Tax</b>	<b>(7)</b>	<b>8</b>	<b>1</b>	<b>238</b>	<b>(182)</b>	<b>56</b>

(\$ millions)	Nine Months Ended September 30,					
	2019			2018		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	38	151	189	1,491	(457)	1,034
Refining	(14)	1	(13)	2	(1)	1
Interest Rate	1	7	8	-	(50)	(50)
Foreign Exchange	(1)	(2)	(3)	(2)	-	(2)
<b>(Gain) Loss on Risk Management</b>	<b>24</b>	<b>157</b>	<b>181</b>	<b>1,491</b>	<b>(508)</b>	<b>983</b>
Income Tax Expense (Recovery)	(7)	(38)	(45)	(404)	135	(269)
<b>(Gain) Loss on Risk Management, After Tax</b>	<b>17</b>	<b>119</b>	<b>136</b>	<b>1,087</b>	<b>(373)</b>	<b>714</b>

In the third quarter of 2019, we incurred realized gains on crude oil risk management activities as our contract prices exceeded settlement prices. On a year-to-date basis, we incurred realized losses on crude oil risk management activities as settlement prices exceeded our contract prices. Unrealized losses of \$9 million and \$151 million were recorded on our crude oil financial instruments in the three and nine months ended September 30, 2019, respectively, primarily due to the realization of settled positions and changes in market prices.

## 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.

### 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. Further to those areas discussed in the annual Consolidated Financial Statement for the year ended December 31, 2018 and the annual MD&A, determining the lease term under IFRS 16, requires critical judgments.

Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option on a lease. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

### 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 nine months ended September 30, 2019.

Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2018.

### Changes in Accounting Policies

#### Leases

Effective January 1, 2019, we adopted IFRS 16. We applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the consolidated balance sheet, consolidated statements of earnings, other comprehensive income, shareholders' equity and cash flows have not been restated.

On adoption, Management elected to use the following practical expedients permitted under the new standard:

- 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;

- Account for lease and non-lease components as a single lease component for lease liabilities related to storage tanks; and
- Use the Company's previous assessment under IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") for onerous contracts instead of reassessing the ROU asset for impairment on January 1, 2019.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "*Leases*" ("IAS 17"). Under the principles of the new standard these leases have been measured at the present value of the remaining lease payments, discounted using our incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 range from 4.0 percent to 5.7 percent. Leases with a remaining term of less than twelve months and low-value leases were excluded. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019 less any amount previously recognized under IAS 37 for onerous contracts with no impact on retained earnings.

The impact of the adoption of IFRS 16 as at January 1, 2019 is as follows:

- Recorded lease liabilities of \$1.5 billion, of which \$128 million was the current portion;
- Recorded ROU assets of \$893 million, equal to the lease liabilities less the previously recognized onerous contract provisions and a \$16 million net investment in finance leases;
- Decreased the onerous contract provisions by \$585 million, offsetting the ROU asset; and
- Recognized certain subleases as a net investment in finance leases (\$16 million) that were classified as operating leases under IAS 17.

The adoption of the new standard had the following impact to our year-to-date 2019 financial results compared with what would have occurred had we not adopted the new accounting policy:

- Decrease in purchased product of \$26 million;
- Decrease to transportation and blending costs of \$57 million;
- Decrease to operating costs of \$3 million;
- Decrease to general and administrative expenses of \$48 million;
- Increase to DD&A expense of \$112 million; and
- Increase in finance expenses of \$59 million.

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 3 to the interim Consolidated Financial Statements.

### ***Uncertain Tax Positions***

Effective January 1, 2019, we adopted International Financial Reporting Interpretation Committee ("IFRIC") 23, "*Uncertainty over Income Tax Treatments*" using the modified approach. The interpretation provides clarity on how to account for a tax position when there is uncertainty over income tax treatments. In determining the likely resolution of the uncertain tax positions, a position may be considered separately or as a group. In addition, an assessment is required to determine the probability that the tax authority will accept the tax position taken in income tax filings. If the uncertain income tax treatment is unlikely to be accepted, the accounting tax position must reflect an appropriate level of uncertainty. An uncertain tax position may be reassessed if new information changes the original assessment. The adoption of IFRIC 23 did not have a material impact on the interim Consolidated Financial Statements.

### **New Accounting Standards and Interpretations not yet Adopted**

There were no new or amended standards issued during the nine months ended September 30, 2019 that are applicable to Cenovus in future periods.

## **CONTROL ENVIRONMENT**

---

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended September 30, 2019 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 to experience continued commodity price volatility and market access constraints for heavy oil exiting Alberta for the remainder of 2019 and to the end of 2020. Transportation challenges are expected to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects, such as the Trans Mountain Pipeline Expansion ("TMX") Project, to progress quickly. While our production

levels have been impacted by the government mandated production curtailments, the resulting narrowing price differentials are anticipated to continue to have a positive impact on our cash flows. Curtailment restrictions are expected to remain in place over the remainder of 2019 and throughout 2020. Ramp up of Christina Lake phase G production will depend on production curtailments, crude-by-rail takeaway capacity ramping up and the reduction of pipeline congestion.

We continue to look for ways to increase our margins through strong operating performance and cost leadership, while focusing on safe and reliable operations. Proactively managing our market access commitments and opportunities assists with our goal of reaching a broader customer base to secure a higher sales price for our liquids production. We continue to take delivery of railcars to support our plan to increase crude-by-rail shipments to approximately 100,000 barrels per day by the end of 2019, as pipeline construction continues to be stalled.

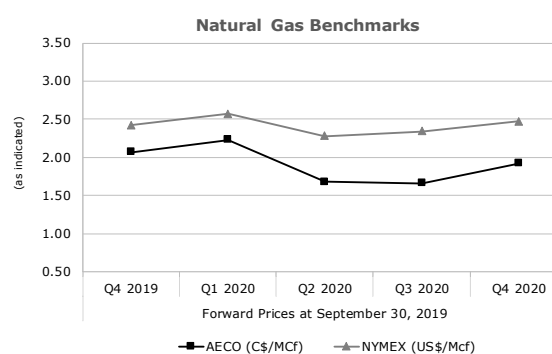
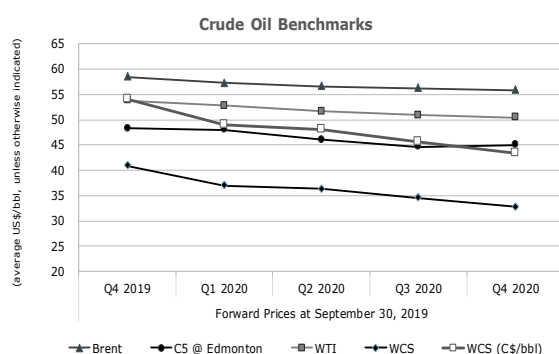
We have reduced the amount of capital needed to sustain our base business and expand our projects, through a continued focus on capital discipline and cost reduction, which we believe will further help support our financial resilience.

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

### Commodity Prices Underlying our Financial Results

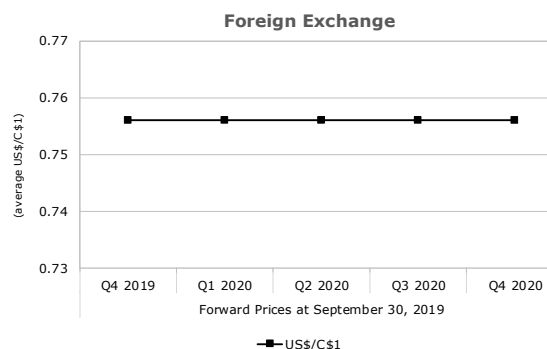
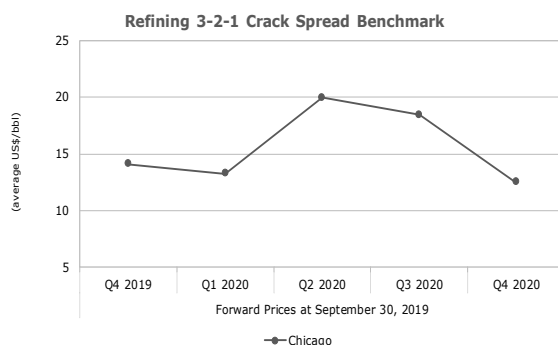
Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and global demand impacts amid the escalation of trade conflicts;
- Overall, crude oil price volatility is expected to increase due to increased Middle East geopolitical risks and as global inventories draw down to backfill lost production from Saudi Arabia;
- Continuing OPEC supply cuts, enforcement of Iranian sanctions, and Venezuelan production declines will be supportive of the narrowing of global light-heavy crude oil price differentials;
- We expect that the WTI-WCS differential will remain largely tied to the extent to which production curtailments in Alberta remain in place, the completion of the TMX Project, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, and the level of crude-by-rail activity;
- We anticipate that the pending International Maritime Organization ("IMO") regulations will cause light-heavy crude oil price differentials to widen, although the magnitude and duration of the widening remains uncertain; and
- We expect refining crack spreads will likely continue to fluctuate, adjusting for seasonal trends, and will narrow and widen in tandem with the Brent-WTI differentials. Refining margins will also be impacted by the IMO regulations.



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 lower than NYMEX, reflecting transportation costs.

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, and emerging macro-economic factors. The Bank of Canada raised its benchmark lending rate in October 2018, but the rate has remained unchanged since, marking a notable shift for Canada towards potentially easing future rate hikes.



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 light-heavy crude oil price differentials through the following:

- 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 and entering into agreements with third parties to move additional rail volumes to alleviate a portion of near-term takeaway capacity constraints;
- 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;
- 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;
- 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, mandated production curtailments and crude oil price differentials; and
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions related to our exposures.

### Key Priorities For 2019 and our Five-Year Business Plan

We recently updated our five-year business plan. Our corporate strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. The five-year business plan allows for disciplined production growth, subject to improved market access, and provides potential for significant Free Funds Flow generation through 2024 in a WTI price environment of US\$45.00 per barrel. In 2020, we expect to be well positioned to increase shareholder returns while we continue to focus on deleveraging, remaining disciplined with our capital investment, improving market access, maintaining cost leadership, and advancing focused technology and innovation to achieve margin improvement and environmental benefits.

### Deleveraging and Disciplined Capital Investment

Our commitment to balance sheet strength and capital discipline has allowed us to achieve our interim Net Debt target of \$7.0 billion. Deleveraging continues to be a top priority and we are targeting \$5 billion as our longer-term Net Debt target. Improving our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority.

On October 2, 2019, we updated our 2019 guidance. Capital investment is anticipated to be between \$1.1 billion and \$1.2 billion. Our oil sands production is expected to range between 345,000 and 361,000 barrels per day for 2019, dependent on the length of mandated production curtailments, as well as the continued ramp up of our crude-by-rail program to ship 100,000 barrels per day by the end of 2019. The majority of our 2019 capital budget is directed towards sustaining oil sands production. In response to the current commodity price environment and our continued focus on near-term debt reduction, we are taking a very disciplined approach in the Deep Basin, with the goal of reducing costs, improving efficiencies and maximizing value. With integration remaining an important part of our overall strategy, capital investment is also allocated for reliability work at the Refineries.

As at September 30, 2019, our Net Debt position was \$6.8 billion. Through a combination of cash on hand and available capacity on our committed credit facility, we have approximately \$4.9 billion of liquidity as at September 30, 2019. Subsequent to September 30, 2019 we repaid, at maturity, in full our 5.70 percent unsecured notes with a remaining principal of US\$500 million and repurchased a further US\$13 million of our 4.45 percent unsecured notes due September 15, 2042 for cash of US\$13 million.

Over the long-term, we continue to target 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.

We remain committed to increasing shareholder value through cost leadership, capital discipline and safe and reliable operations. These commitments, in combination with our high-quality upstream assets and joint ownership in strong refining assets, are expected to strengthen our ability to generate Free Funds Flow and continue to deleverage our balance sheet.

### ***Shareholder Returns***

While deleveraging remains a top priority for Cenovus, we believe we have built significant financial resilience into our business. Our updated five-year business plan is expected to provide the capacity to fund opportunistic share repurchases and sustainably grow our dividend.

On October 2, 2019, we announced a 25 percent dividend increase to \$0.0625 per share for the fourth quarter of 2019, payable on December 31, 2019, to shareholders of record on December 13, 2019. We believe we will have capacity for further dividend increases at a potential growth rate of between five percent and 10 percent annually, even in a WTI price environment of US\$45.00 per barrel.

### ***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.

### ***Cost Leadership***

Over the past four years, we have achieved significant improvements in our operating and sustaining capital costs. In the remainder of 2019, we will continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions. We expect to realize additional savings through 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.

We believe growth in cash flows and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target.

### ***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 activities with external collaboration in an effort to leverage our technology spend.

## **ADVISORY**

---

### **Oil and Gas Information**

The estimates of reserves were prepared effective December 31, 2018 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, 2019 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, 2018.

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”, “capacity”, “committed”, “commitment”, “could”, “drive”, “expect”, “estimate”, “focus”, “forecast”, “forward”, “future”, “guidance”, “may”, “on track”, “outlook”, “plan”, “position”, “potential”, “priority”, “should”, “strategy”, “target”, “will”, “would” or similar expressions and includes suggestions of future outcomes, including statements about: strategy and related milestones; schedules and plans; focus on maximizing shareholder value through cost leadership; desire to realize the best margins for our products; plans to maintain and demonstrate financial discipline while balancing growth and shareholder return; our targeted five to 10 percent dividend growth; our willingness to consider opportunistic share repurchases, including supporting a potential sale of ConocoPhillips’ ownership of our common shares; 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 2019 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; 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 2019 guidance estimates; expected future production, including the timing, stability or growth thereof; the impact of the Government of Alberta’s mandatory production curtailment; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that our capital investment and any cash dividends for 2019 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; 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 2019; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, 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 results; 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 our 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 2019 guidance, available at [cenovus.com](http://cenovus.com); bottom of the cycle commodity prices of about US\$45/bbl WTI and C\$44/bbl WCS; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; 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; opportunities to repurchase shares for cancellation at prices acceptable to us; future narrowing of crude oil differentials; realization of expected 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; the Government of Alberta’s mandatory production curtailment will continue to maintain a relatively narrow differential between WTI and WCS crude oil prices thereby positively impacting cash flows for Cenovus; the ability of our refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions and plans to ramp up crude-by-rail loading capacity to partially mitigate a portion of our WCS crude oil volumes against wider differentials; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; 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; including potential dividend increases; 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 within the timelines we expect; forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS 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.

2019 guidance, as updated October 1, 2019, assumes: Brent prices of US\$64.00/bbl, WTI prices of US\$57.20/bbl; WCS of US\$45.10/bbl; AECO natural gas prices of \$1.55/Mcf; Chicago 3-2-1 crack spread of US\$16.25/bbl; and an exchange rate of \$0.75 US\$/C\$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: our ability 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; our ability 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; failure of the Government of Alberta's mandatory production curtailment to cause the differential between the WTI and the WCS crude oil prices to narrow or to narrow sufficiently to positively impact our cash flows; unexpected consequences related to the Government of Alberta's mandatory production curtailment; the Government of Alberta may extend mandatory production curtailment beyond when takeaway capacity constraints have been sufficiently relieved; 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 regarding commodity prices, currency and interest rates; 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; our ability to maintain 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 judgments; 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 and our assumptions relating thereto; 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, shareholder proposals 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, 2018, available on SEDAR at [sedar.com](http://sedar.com), on EDGAR at [sec.gov](http://sec.gov), and on our website at [cenovus.com](http://cenovus.com).

## 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		
WTS	West Texas Sour		

## 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

Three Months Ended September 30, 2019 (\$ millions)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Continuing Operations	Condensate	Inventory	Internal Usage <sup>(2)</sup>	Other	Continuing Operations
Gross Sales	2,722	131	2,853	(924)	-	(27)	(14)	1,888
Royalties	336	(4)	332	-	-	-	-	332
Transportation and Blending	1,249	20	1,269	(924)	-	-	-	345
Operating	227	77	304	-	-	(27)	(8)	269
Production and Mineral Taxes	-	1	1	-	-	-	-	1
<b>Netback</b>	<b>910</b>	<b>37</b>	<b>947</b>	-	-	-	(6)	<b>941</b>
(Gain) Loss on Risk Management	(7)	-	(7)	-	-	-	-	(7)
<b>Operating Margin</b>	<b>917</b>	<b>37</b>	<b>954</b>	-	-	-	(6)	<b>948</b>

Three Months Ended September 30, 2018 (\$ millions) <sup>(3)</sup>	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Continuing Operations	Condensate	Inventory	Internal Usage <sup>(2)</sup>	Other	Continuing Operations
Gross Sales	2,992	214	3,206	(1,268)	-	(34)	(15)	1,889
Royalties	275	11	286	-	-	-	-	286
Transportation and Blending	1,482	20	1,502	(1,268)	-	-	-	234
Operating	230	103	333	-	-	(34)	(7)	292
Production and Mineral Taxes	-	-	-	-	-	-	-	-
<b>Netback</b>	<b>1,005</b>	<b>80</b>	<b>1,085</b>	-	-	-	(8)	<b>1,077</b>
(Gain) Loss on Risk Management	323	7	330	-	-	-	-	330
<b>Operating Margin</b>	<b>682</b>	<b>73</b>	<b>755</b>	-	-	-	(8)	<b>747</b>

Nine Months Ended September 30, 2019 (\$ millions)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Continuing Operations	Condensate	Inventory	Internal Usage <sup>(2)</sup>	Other	Continuing Operations
Gross Sales	8,179	501	8,680	(2,961)	-	(140)	(51)	5,528
Royalties	827	20	847	-	-	-	-	847
Transportation and Blending	3,736	62	3,798	(2,961)	-	-	-	837
Operating	771	257	1,028	-	-	(140)	(27)	861
Production and Mineral Taxes	-	1	1	-	-	-	-	1
<b>Netback</b>	<b>2,845</b>	<b>161</b>	<b>3,006</b>	-	-	-	(24)	<b>2,982</b>
(Gain) Loss on Risk Management	38	-	38	-	-	-	-	38
<b>Operating Margin</b>	<b>2,807</b>	<b>161</b>	<b>2,968</b>	-	-	-	(24)	<b>2,944</b>

Nine Months Ended September 30, 2018 (\$ millions) <sup>(3)</sup>	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Continuing Operations	Condensate	Inventory	Internal Usage <sup>(2)</sup>	Other	Continuing Operations
Gross Sales	8,646	714	9,360	(3,967)	-	(131)	(49)	5,213
Royalties	512	62	574	-	-	-	-	574
Transportation and Blending	4,616	72	4,688	(3,967)	-	-	(4)	717
Operating	789	303	1,092	-	-	(131)	(28)	933
Production and Mineral Taxes	-	1	1	-	-	-	-	1
<b>Netback</b>	<b>2,729</b>	<b>276</b>	<b>3,005</b>	-	-	-	(17)	<b>2,988</b>
(Gain) Loss on Risk Management	1,465	26	1,491	-	-	-	-	1,491
<b>Operating Margin</b>	<b>1,264</b>	<b>250</b>	<b>1,514</b>	-	-	-	(17)	<b>1,497</b>

(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.

(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

## Oil Sands

Three Months Ended September 30, 2019 (\$ millions)	Basis of Netback Calculation			Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	879	917	1,796	-	924	-	2	2,722
Royalties	147	189	336	-	-	-	-	336
Transportation and Blending	196	129	325	-	924	-	-	1,249
Operating	119	106	225	-	-	-	2	227
<b>Netback</b>	<b>417</b>	<b>493</b>	<b>910</b>	-	-	-	-	<b>910</b>
(Gain) Loss on Risk Management	(3)	(4)	(7)	-	-	-	-	(7)
<b>Operating Margin</b>	<b>420</b>	<b>497</b>	<b>917</b>	-	-	-	-	<b>917</b>

Three Months Ended September 30, 2018 (\$ millions) <sup>(2)</sup>	Basis of Netback Calculation			Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	845	876	1,721	-	1,268	-	3	2,992
Royalties	187	88	275	-	-	-	-	275
Transportation and Blending	106	108	214	-	1,268	-	-	1,482
Operating	118	112	230	(1)	-	-	1	230
<b>Netback</b>	<b>434</b>	<b>568</b>	<b>1,002</b>	<b>1</b>	-	-	2	<b>1,005</b>
(Gain) Loss on Risk Management	134	189	323	-	-	-	-	323
<b>Operating Margin</b>	<b>300</b>	<b>379</b>	<b>679</b>	<b>1</b>	-	-	2	<b>682</b>

Nine Months Ended September 30, 2019 (\$ millions)	Basis of Netback Calculation			Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	2,564	2,645	5,209	-	2,961	-	9	8,179
Royalties	356	471	827	-	-	-	-	827
Transportation and Blending	467	308	775	-	2,961	-	-	3,736
Operating	394	369	763	-	-	-	8	771
<b>Netback</b>	<b>1,347</b>	<b>1,497</b>	<b>2,844</b>	-	-	-	1	<b>2,845</b>
(Gain) Loss on Risk Management	15	23	38	-	-	-	-	38
<b>Operating Margin</b>	<b>1,332</b>	<b>1,474</b>	<b>2,806</b>	-	-	-	1	<b>2,807</b>

Nine Months Ended September 30, 2018 (\$ millions) <sup>(2)</sup>	Basis of Netback Calculation			Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	2,266	2,405	4,671	1	3,967	-	7	8,646
Royalties	376	136	512	-	-	-	-	512
Transportation and Blending	354	295	649	-	3,967	-	-	4,616
Operating	409	371	780	1	-	-	8	789
<b>Netback</b>	<b>1,127</b>	<b>1,603</b>	<b>2,730</b>	-	-	-	(1)	<b>2,729</b>
(Gain) Loss on Risk Management	638	827	1,465	-	-	-	-	1,465
<b>Operating Margin</b>	<b>489</b>	<b>776</b>	<b>1,265</b>	-	-	-	(1)	<b>1,264</b>

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A

## Deep Basin

	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total	Other <sup>(2)</sup>	Total Deep Basin
Three Months Ended			
September 30, 2019 (\$ millions)			
Gross Sales	119	12	131
Royalties	(4)	-	(4)
Transportation and Blending	20	-	20
Operating	71	6	77
Production and Mineral Taxes	1	-	1
<b>Netback</b>	<b>31</b>	<b>6</b>	<b>37</b>
(Gain) Loss on Risk Management	-	-	-
<b>Operating Margin</b>	<b>31</b>	<b>6</b>	<b>37</b>

	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total	Other <sup>(2)</sup>	Total Deep Basin
Three Months Ended			
September 30, 2018 (\$ millions) <sup>(3)</sup>			
Gross Sales	202	12	214
Royalties	11	-	11
Transportation and Blending	20	-	20
Operating	97	6	103
<b>Netback</b>	<b>74</b>	<b>6</b>	<b>80</b>
(Gain) Loss on Risk Management	7	-	7
<b>Operating Margin</b>	<b>67</b>	<b>6</b>	<b>73</b>

	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total	Other <sup>(2)</sup>	Total Deep Basin
Nine Months Ended			
September 30, 2019 (\$ millions)			
Gross Sales	459	42	501
Royalties	20	-	20
Transportation and Blending	62	-	62
Operating	238	19	257
Production and Mineral Taxes	1	-	1
<b>Netback</b>	<b>138</b>	<b>23</b>	<b>161</b>
(Gain) Loss on Risk Management	-	-	-
<b>Operating Margin</b>	<b>138</b>	<b>23</b>	<b>161</b>

	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total	Other <sup>(2)</sup>	Total Deep Basin
Nine Months Ended			
September 30, 2018 (\$ millions) <sup>(3)</sup>			
Gross Sales	672	42	714
Royalties	62	-	62
Transportation and Blending	68	4	72
Operating	283	20	303
Production and Mineral Taxes	1	-	1
<b>Netback</b>	<b>258</b>	<b>18</b>	<b>276</b>
(Gain) Loss on Risk Management	26	-	26
<b>Operating Margin</b>	<b>232</b>	<b>18</b>	<b>250</b>

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

(2) Reflects operating margin from processing facility.

(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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

**Sales Volumes**

(barrels per day, unless otherwise stated)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2019	2018	2019	2018
<b>Oil Sands</b>				
Foster Creek	162,199	171,936	159,108	169,006
Christina Lake	192,929	206,688	182,680	209,909
<b>Total Oil Sands Crude Oil</b>	<b>355,128</b>	378,624	<b>341,788</b>	378,915
<b>Natural Gas</b> (MMcf per day)	-	-	-	2
<b>Total Oil Sands</b> (BOE per day)	<b>355,128</b>	378,625	<b>341,788</b>	379,189
<b>Deep Basin</b>				
<b>Total Liquids</b>	<b>26,104</b>	32,269	<b>26,835</b>	33,918
<b>Natural Gas</b> (MMcf per day)	<b>407</b>	520	<b>432</b>	546
<b>Total Deep Basin</b> (BOE per day)	<b>93,901</b>	118,920	<b>98,807</b>	124,984
<b>Less: Internal Consumption</b> <sup>(1)</sup> (MMcf per day)	<b>(304)</b>	(293)	<b>(314)</b>	(305)
<b>Sales From Continuing Operations</b> <sup>(1)</sup> (BOE per day)	<b>398,304</b>	448,712	<b>388,237</b>	453,340

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