

# Third Quarter

2017

**cenovus**  
ENERGY

## Cenovus reports solid third quarter results Achieves strong adjusted funds flow accretion from acquisition

**Calgary, Alberta (November 2, 2017)** – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) delivered strong cash from operating activities and adjusted funds flow in the third quarter including three full months of solid contribution from the oil sands and Deep Basin assets acquired on May 17, 2017. To further optimize its portfolio and deleverage its balance sheet, the company has announced sale agreements for its Pelican Lake, Suffield and Palliser assets for combined gross cash proceeds of approximately \$2.8 billion. Cenovus continues to target \$4 billion to \$5 billion of cumulative announced sale agreements in 2017. Through a continued focus on capital discipline and strong operational performance, Cenovus generated \$544 million in free funds flow in the quarter.

### Key highlights

- Increased third quarter cash from operating activities and adjusted funds flow by 91% and 133% respectively, compared with the same period in 2016
- Recorded a net loss of \$69 million, a 73% improvement over Q3 2016
- Retired \$950 million of the company's \$3.6 billion asset-sale bridge facility
- Reduced planned 2017 capital spending guidance by \$100 million to \$1.6 billion at the midpoint with no expected impact to production in core areas. The reduced capital forecast reflects further cost and capital improvements achieved this year.

### Financial & production summary

(For the period ended September 30)	2017 Q3	2016 Q3	% change
Financial <sup>1</sup> (\$ millions, except per share amounts)			
Cash from operating activities	592	310	91
Adjusted funds flow <sup>2</sup>	982	422	133
Per share diluted	0.80	0.51	
Free funds flow <sup>2</sup>	544	214	154
Operating earnings/loss <sup>2</sup>	340	-236	
Per share diluted	0.28	-0.28	
Net loss <sup>3</sup>	-69	-251	
Per share diluted	-0.06	-0.30	
Capital investment	438	208	111
Production (before royalties)			
Oil sands (bbls/d)	362,494	153,591	136
Deep Basin liquids <sup>4</sup> (bbls/d)	32,864	n/a	n/a
Conventional oil <sup>4,5</sup> (bbls/d)	53,697	54,481	-1
<b>Total oil and liquids (bbls/d)</b>	<b>449,055</b>	<b>208,072</b>	<b>116</b>
Deep Basin natural gas (MMcf/d)	495	n/a	n/a
Conventional natural gas <sup>5</sup> (MMcf/d)	356	392	-9
<b>Total natural gas (MMcf/d)</b>	<b>851</b>	<b>392</b>	<b>117</b>
<b>Total production (BOE/d)</b>	<b>590,851</b>	<b>273,405</b>	<b>116</b>

<sup>1</sup> Financial information includes results from discontinued operations.

<sup>2</sup> Adjusted funds flow, free funds flow and operating earnings/loss are non-GAAP measures. See Advisory.

<sup>3</sup> Net loss includes a non-cash after-tax loss of approximately \$440 million related to the disposition of Cenovus's Pelican Lake assets.

<sup>4</sup> Includes natural gas liquids (NGLs).

<sup>5</sup> Majority of assets have been sold, have sale agreements in place or are being marketed and are presented as discontinued operations. Conventional natural gas includes 6 MMcf/d of Athabasca natural gas for Q3 2017.

## Overview

In the third quarter of 2017, Cenovus continued to realize the benefits of its May 17, 2017 asset acquisition, which included taking complete ownership of its best-in-class oil sands assets in northern Alberta and adding a new core production area in the Deep Basin in Alberta and British Columbia. With a full quarter contribution from the acquired assets, the company increased cash from operating activities and adjusted funds flow by 91% and 133% respectively, free funds flow by 154% and total production by 116% compared with the third quarter of 2016.

### Planned asset divestitures

As part of its strategy, the company is focused on its two core production areas - the oil sands and the Deep Basin. To further optimize its portfolio, Cenovus put its legacy conventional oil and natural gas assets up for sale in the first half of 2017. The company has successfully closed the sale of its Pelican Lake assets and used the net proceeds from the transaction to repay the first tranche and a portion of the second tranche of its \$3.6 billion asset-sale bridge facility. Sale agreements have also been announced for the Suffield and Palliser assets and, upon closing, Cenovus intends to apply the net proceeds from those transactions to further reduce the bridge facility. The company is also in the final stages of an analysis of its Deep Basin assets with a view to identifying non-core properties for potential sale.

"I'm very pleased with the progress we've made so far in streamlining our portfolio and reducing near-term leverage, which remains our top priority," said Brian Ferguson, Cenovus President & Chief Executive Officer. "I believe the sale agreements reached to date and the significant interest in our Weyburn operation showcase the quality of these assets and they give me confidence that we will deliver on our 2017 divestiture target."

### CEO succession plan

Mr. Ferguson is retiring as President & Chief Executive Officer and as a director of the company as of the end of today, November 2, 2017 and will continue in an advisory role reporting to the Board Chair until March 31, 2018 to facilitate the leadership transition. As announced on October 30, 2017, Cenovus is pleased to introduce Alex Pourbaix as President & Chief Executive Officer beginning on November 6, 2017.

### Financial performance

During the third quarter, Cenovus generated adjusted funds flow of \$982 million or \$0.80 per share compared with \$422 million or \$0.51 per share in the same period a year earlier. This was mostly due to higher liquids and natural gas sales volumes, higher realized liquids pricing as well as higher average benchmark crack spreads compared with 2016. The increase in adjusted funds flow was partially offset by realized foreign exchange losses on working capital, a rise in finance costs primarily associated with additional debt incurred to finance the acquisition and higher general and administrative (G&A) costs.

Third quarter cash from operating activities was \$592 million, compared with \$310 million in the same period in 2016. The company's combined upstream portfolio generated operating margin net of capital investment of \$626 million in the third quarter, including a full three months of contribution from the acquired assets. Cenovus had third quarter free funds flow of \$544 million compared with \$214 million in the same period of 2016. Year to date,

Cenovus has generated over \$1 billion of free funds flow, even with the benchmark price of West Texas Intermediate (WTI) crude oil averaging less than US\$50.00 per barrel.

Net loss was \$69 million during the third quarter, compared with a loss of \$251 million in the same period in 2016. The net loss includes a non-cash after-tax loss of approximately \$440 million related to the disposition of Cenovus's Pelican Lake assets. Operating earnings were \$340 million in the third quarter, compared with a loss of \$236 million in the same period in 2016.

### Hedging

Concurrent with its asset sale processes and to further support the company's financial resilience while the balance of the asset-sale bridge loan remains outstanding, Cenovus has accelerated its hedging program and has hedged a greater percentage of forecast liquids and natural gas volumes. As of October 25, 2017, the company had crude oil hedges in place on 249,000 barrels per day (bbls/d) for the remainder of this year at an average floor price of approximately US\$50.72/bbl. The company also had 325,000 bbls/d hedged for the first half of 2018 with an average floor price of approximately US\$50.09/bbl and 150,000 bbls/d with an average floor price of approximately US\$49.16/bbl for the second half of 2018. As of October 25, 2017 Cenovus had natural gas hedges in place at an average New York Mercantile Exchange (NYMEX) price of approximately US\$3.07 per million British thermal units per day (MMBtu/d) on 202,000 MMBtu/d for the remainder of 2017. Cenovus's 2018 hedging activity is weighted towards the first half of the year and focused on providing downside price protection. The company expects to get back to a more normalized level of hedging subsequent to the completion of its asset sale program.

### Current hedge positions for 2017

Hedges at October 25, 2017	Volume	Price
<b>Crude – Brent Fixed Price</b> October - December	144,000 bbls/d	US\$51.23/bbl
<b>Crude – WTI Collars</b> October - December	50,000 bbls/d	US\$44.84/bbl - US\$56.47/bbl
<b>Crude – Brent Put Contracts</b> October - December	55,000 bbls/d	US\$53.00/bbl
<b>Crude – Brent - WTI Spread</b> October - December	50,000 bbls/d	US\$(1.88)/bbl
<b>Natural Gas – NYMEX Fixed Price</b> October - December	~202,000 MMBtu/d	~US\$3.07/MMBtu

### Current hedge positions for 2018

Hedges at October 25, 2017	Volume	Price
<b>Crude – Brent Collars</b> January - June	80,000 bbls/d	US\$49.54/bbl - US\$59.86/bbl
<b>Crude – Brent Fixed Price</b> January - June	60,000 bbls/d	US\$53.34/bbl
<b>Crude – Brent Put Contracts</b> January - June	25,000 bbls/d	US\$53.00/bbl
<b>Crude – WTI Collars</b> January - June	10,000 bbls/d	US\$45.30/bbl - US\$62.77/bbl

## Current hedge positions for 2018

Hedges at October 25, 2017	Volume	Price
<b>Crude – WTI Fixed Price</b> January - June	150,000 bbls/d	US\$48.91/bbl
<b>Crude – WCS Differential</b> January - June	~25,200 bbls/d	~US\$(13.92)/bbl
<b>Crude – WTI Fixed Price</b> July - December	75,000 bbls/d	US\$49.32/bbl
<b>Crude – Brent Collars</b> July - December	75,000 bbls/d	US\$49.00/bbl - US\$59.69/bbl
<b>Crude – WCS Differential</b> July - December	~9,600 bbls/d	~US\$(14.48)/bbl

### Continued cost leadership & capital discipline

Since 2014, Cenovus has achieved significant cost reductions across its business, including reducing its per-barrel oil sands non-fuel operating costs by more than 30% and its per-barrel oil sands sustaining capital costs by 50%. As part of its continued focus on cost leadership, the company is committed to achieving an additional \$1 billion of cumulative capital, operating and G&A cost reductions over the next three years.

To reflect the expected ongoing cost savings and efficiency improvements in its base business as well as the company's continued focus on capital discipline, Cenovus has further updated its capital spending guidance for 2017. Compared with the company's July 26, 2017 guidance, total planned capital expenditures this year have been reduced by another \$100 million at the midpoint, with no expected impact to forecast production volumes for Cenovus's core areas in the oil sands and Deep Basin. The majority of the reduced capital spending forecast relates to continued improvements in drilling performance, development planning and optimized scheduling of well start-ups at Cenovus's oil sands operations. Updated guidance is available at [cenovus.com](http://cenovus.com) under Investors.

Cenovus plans to take a disciplined approach to capital investment for 2018, prioritizing near-term debt reduction and increased free funds flow over production growth. The company intends to provide its 2018 budget overview later this year.

## Operating highlights

### Oil sands

Production at Cenovus's Christina Lake and Foster Creek oil sands operations rose to 362,494 bbls/d in the third quarter of 2017, an increase of 136% from the same period a year ago. The increase was mainly due to the acquisition and to incremental volumes from Foster Creek phase G and Christina Lake phase F, both of which began producing in the second half of 2016. Production at Foster Creek was impacted by temporary treating issues during the month of August, which are routinely encountered with the start-up of new sustaining well pads. Volumes recovered through September and the project continues to be on track to meet full-year production guidance.

At Foster Creek, the steam to oil ratio (SOR), the amount of steam needed to produce one barrel of oil, was 2.5 in the third quarter of 2017, compared with 2.6 in the same period of 2016. At Christina Lake, the SOR was 1.8 in the third quarter of 2017, compared with 1.9 a year earlier.

Construction at Christina Lake phase G resumed in the first quarter of 2017, and activity has increased through the third quarter. The expansion, which is expected to be completed with go-forward capital investment of between \$16,000 and \$18,000 per flowing barrel, is anticipated to begin production in the second half of 2019.

### **Deep Basin**

Integration of the company's newly acquired Deep Basin assets has gone according to plan and the company is pleased with the execution of its capital program to date. Production from the Deep Basin averaged 115,301 barrels of oil equivalent per day (BOE/d), in line with the company's expectations. Cenovus continues to take a disciplined approach to development, with plans to peak at seven active rigs and drill 28 wells across the Deep Basin by year-end.

### **Downstream**

Operating margin from refining and marketing was \$211 million in the quarter, compared with \$68 million in the same period of 2016. The increase was largely the result of higher average market crack spreads, partially offset by narrower light-heavy oil differentials and the appreciating value of the Canadian dollar. The company's refining operating margin is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's operating margin from refining and marketing would have been \$9 million lower in the quarter. In the third quarter of 2016, operating margin would have been \$33 million higher on a LIFO reporting basis.

### **Other developments**

For the fourth quarter of 2017, the Board of Directors has declared a dividend of \$0.05 per share, payable on December 29, 2017 to common shareholders of record as of December 15, 2017. Based on the November 1, 2017 closing share price on the Toronto Stock Exchange of \$13.01, this represents an annualized yield of about 1.5%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", or "Cenovus", mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated November 1, 2017, should be read in conjunction with our September 30, 2017 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2016 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2016 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of November 1, 2017, 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. The information in this MD&A, as it relates to our operations for the three and nine months ended September 30, 2017, reflects the closing of the Acquisition (as defined in this MD&A) on May 17, 2017. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at [sedar.com](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, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

### Non-GAAP Measures and Additional Subtotals

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

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

## OVERVIEW OF CENOVUS

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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, 2017, we had an enterprise value of approximately \$27 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Western Canada. We also conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "liquids") production for the three months ended September 30, 2017 was 449,055 barrels per day, our average natural gas production was 851 MMcf per day, and our total reported production was 590,851 BOE per day. The refining operations processed an average of 462,000 gross barrels per day of crude oil feedstock into an average of 490,000 gross barrels per day of refined products.

### Our Strategy

On May 17, 2017, we closed an acquisition from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") where we acquired their 50 percent interest in FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional assets in Alberta and British Columbia ("the Acquisition"). In order to finance the Acquisition, we incurred additional debt. We are focused on deleveraging our balance sheet through the sale of our legacy Conventional crude oil and natural gas assets and generating increased Free Funds Flow.

We updated our strategy in the second quarter of 2017 to reflect the closing of the Acquisition and our increased focus on Free Funds Flow. Our strategy is to increase cash flows through disciplined production growth from our vast portfolio of oil sands and Deep Basin natural gas and liquids assets in Western Canada. We are focused on increasing our current share price and maximizing shareholder value through cost leadership and realizing the best margins for our products to help us maintain financial resilience and deliver sustainable dividend growth. We plan to achieve our strategy by drawing on the expertise of our people and leveraging our strategic differentiators: premium asset quality, executional excellence, value-added integration, focused innovation and trusted reputation.

We measure our performance through a balanced scorecard that reflects our financial, operational, safety, environmental and organizational health goals.

### Our Key Strategic Differentiators

#### Premium Asset Quality

Cenovus has a deep portfolio of premium-quality oil sands, conventional oil, and natural gas assets that we believe provide us with significant cost and environmental performance advantages. Our in-situ oil sands projects and Deep Basin assets in Western Canada offer long- and short-cycle opportunities that provide the capital investment flexibility to position us to deliver value growth at various points of the price cycle. In addition to our exploration and production assets, we have complementary interests in refineries and product transportation infrastructure.

## Executorial Excellence

Our team is committed to delivering on our business plan in a safe, disciplined and responsible manner and continuously improving our performance to help manage risk and optimize returns. We use a manufacturing approach to support consistent performance and enhance reliability. This involves applying standardized and repeatable designs and processes to the construction and operation of our facilities to reduce costs and improve efficiencies at all project stages. We strive to execute our work in an agile manner with a focus on using our resources effectively.

## Value-Added Integration

Our integrated business approach helps provide stability to our cash flows and maximize value for the oil and natural gas we produce. Having ownership in oil refineries positions us to capture the full value chain from production to high-quality end products like transportation fuels. In addition, our pipeline commitments, marine capability, crude-by-rail loading facility and product marketing activities position us to obtain global pricing for our oil. As a consumer of natural gas at our oil sands facilities and refineries, our natural gas production acts as an economic hedge to help manage price volatility. In addition, our cogeneration plants efficiently provide power for our oil sands facilities with the added value of excess electricity being sold to the grid.

## Focused Innovation

We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, aggressively 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 embrace the “fail fast” mentality as essential to encouraging behaviours that can transform how we operate. The application of digital innovation across our business is expected to be a key contributor to our competitive advantage. We aim to complement our internal technology development efforts with external collaboration that brings together smart people with diverse ideas that leverage our technology spend.

## Trusted Reputation

We are a responsible, progressive company that is committed to providing a safe and healthy workplace, building strong external relationships, minimizing our environmental footprint and being a part of a zero-emissions future. Our actions are intended to support our trusted reputation and enable us to attract and retain top-quality staff and to engage with and be respected by our stakeholders: investors, the communities in which we operate, environmental groups, governments, Aboriginal people, media, project partners and the general public.

## Our Operations

### Oil Sands

Our oil sands assets include steam-assisted gravity drainage (“SAGD”) oil sands projects in northern Alberta, including Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects, located in the Athabasca region of northeastern Alberta, are 100 percent owned by Cenovus following the Acquisition. Our 100 percent-owned emerging project at Telephone Lake is located within the Borealis region of northeastern Alberta. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

(\$ millions)	Nine Months Ended September 30, 2017	
	Crude Oil	Natural Gas
Operating Margin	1,612	3
Capital Investment	654	6
<b>Operating Margin Net of Related Capital Investment</b>	<b>958</b>	<b>(3)</b>

### Deep Basin

The Deep Basin includes approximately three million net acres of land rich in natural gas, condensate and other NGLs, and light and medium oil. The assets are located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas and include interests in numerous natural gas processing facilities (collectively, the “Deep Basin Assets”). The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development and provide an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations. The Deep Basin Assets were acquired on May 17, 2017.

(\$ millions)	May 17 – September 30, 2017
	Operating Margin
Capital Investment	77
<b>Operating Margin Net of Related Capital Investment</b>	<b>42</b>

### Conventional

Our Conventional segment has been classified as a discontinued operation. We are currently marketing for sale or have sales agreements in place for the remaining assets within our Conventional segment. In the third quarter, we sold our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project, for gross cash proceeds of \$975 million. We also announced the divestiture of our Suffield crude oil and natural gas assets for gross cash proceeds of \$512 million. The sale is expected to close in the fourth quarter of 2017, subject to customary closing conditions.

On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$1.3 billion. The sale of the Palliser assets is expected to close in the fourth quarter of 2017, subject to customary closing conditions.

Crude oil production from our Conventional business segment generates dependable near-term cash flows while the natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

(\$ millions)	Nine Months Ended September 30, 2017	
	Liquids	Natural Gas
Operating Margin	310	109
Capital Investment	173	7
<b>Operating Margin Net of Related Capital Investment</b>	<b>137</b>	<b>102</b>

### Refining and Marketing

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

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

(\$ millions)	Nine Months Ended September 30, 2017
	Operating Margin
Capital Investment	124
<b>Operating Margin Net of Related Capital Investment</b>	<b>160</b>

## FINANCING THE ACQUISITION

On May 17, 2017, we closed the Acquisition which provided us with control over our oil sands operations, doubled our oil sands production, and almost doubled our proved bitumen reserves. In addition, the Deep Basin Assets provide a second core operating area with more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia. The Deep Basin Assets are expected to provide complementary short-cycle development opportunities with high-return potential.

The safe and efficient integration of the Deep Basin Assets is on track and continues to be a top priority for Cenovus. We are committed to ensuring responsible operations as we establish ourselves as a new operator in the Deep Basin area.

To finance the Acquisition, we:

- Completed an offering for US\$2.9 billion of senior unsecured notes;
- Borrowed \$3.6 billion under a committed asset sale bridge credit facility ("Bridge Facility");
- Completed a Bought-Deal Common Share Offering for 187.5 million common shares, raising gross proceeds of \$3.0 billion;
- Issued 208 million common shares as part of the consideration paid to ConocoPhillips; and
- Funded the remainder of the purchase price with cash on hand and a draw on our existing committed credit facility.

The financing, which increased the leverage on our balance sheet, was executed according to plan and supported by three investment grade credit ratings. The increase in leverage is expected to be temporary as we are selling



our legacy Conventional crude oil and natural gas assets in order to deleverage our balance sheet. We have completed the first of a series of anticipated divestitures, namely our Pelican Lake assets and the adjacent Grand Rapids project, for gross cash proceeds of \$975 million. Net cash proceeds from the sale have been applied against the \$3.6 billion committed Bridge Facility.

On September 25, 2017, we announced the sale of our Suffield crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$512 million, plus a deferred purchase price adjustment ("DPPA"). The sale includes our crude oil and natural gas assets located on the Canadian Forces Base Suffield and the adjacent Alderson property (collectively, the "Suffield Divestiture"). The DPPA is a two-year agreement that begins on January 1, 2018, with maximum combined purchase price adjustments of \$36 million if average crude oil and natural gas prices rise over the next two years. We are entitled to receive cash for each month in which the average daily price of WTI is above US\$55 per barrel or the price of Henry Hub natural gas is above US\$3.50 per MMBtu. The Suffield Divestiture is expected to close in the fourth quarter, subject to customary closing conditions.

On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$1.3 billion. The sale includes our crude oil and natural gas assets in the areas near Drumheller, Brooks and Langevin (collectively, the "Palliser Divestiture"). The sale of the Palliser assets is expected to close in the fourth quarter of 2017, subject to closing conditions. The divestiture process for our remaining legacy Conventional assets, notably our CO<sub>2</sub> enhanced oil recovery project at Weyburn, in southern Saskatchewan, is proceeding well.

Additional information on the Acquisition is available in our June 30, 2017 MD&A and our news release dated March 29, 2017 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); in our material change report dated April 5, 2017 and in our Business Acquisition Report dated July 19, 2017, both available on SEDAR and EDGAR.

## QUARTERLY HIGHLIGHTS

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We have completed key steps in the plan to deleverage our balance sheet with the announcement of three divestitures, closing one of them. Gross proceeds from these divestitures will total approximately \$2.8 billion.

We generated Free Funds Flow of \$544 million in the quarter, a significant increase from \$214 million in the third quarter of 2016, primarily due to the Acquisition.

Production increased significantly in the quarter to 590,851 BOE per day in 2017 (2016 – 273,405 BOE per day) primarily related to the Acquisition. Incremental production from the Acquisition was 296,549 BOE per day for the three months ended September 30, 2017.

Crude oil prices continued to be volatile in the quarter. WTI ranged from a high of US\$52.22 per barrel to a low of US\$44.23 per barrel and averaged seven percent higher compared with 2016. In addition, AECO was very volatile, ranging from a high of \$2.71 per Mcf to a low of \$1.24 Mcf and averaging seven percent lower than the third quarter of 2016. Our average sales price rose 12 percent from 2016, contributing to a companywide Netback of \$18.40 per BOE in the third quarter, before realized hedging. We continue to focus on cost leadership and capital discipline to help maintain financial resilience, while delivering safe and reliable operations.

In the third quarter, we:

- More than doubled our total liquids production compared with the third quarter of 2016, primarily due to incremental production volumes from the Acquisition and our oil sands expansion phases;
- Generated combined upstream revenues, including the Conventional segment, of \$2,629 million compared with \$1,084 million in 2016, primarily related to a rise in sales volumes and higher liquids sales prices;
- Reported upstream operating costs, including the Conventional segment, of \$476 million, an increase of \$246 million compared with the third quarter of 2016 primarily due to the Acquisition;
- Achieved Cash From Operating Activities and Adjusted Funds Flow of \$592 million and \$982 million, respectively, increasing significantly from the third quarter of 2016;
- Recorded Net Earnings From Continuing Operations of \$288 million (2016 – Net Loss From Continuing Operations of \$55 million);
- Invested \$438 million in capital which allowed us to generate Free Funds Flow of \$544 million in the quarter;
- Sold our Pelican Lake assets and the adjacent Grand Rapids project on September 29, 2017 for gross cash proceeds of \$975 million and repaid the first tranche and a portion of the second tranche of our committed Bridge Facility; and
- Announced the Suffield Divestiture. The sale is expected to close in the fourth quarter, subject to customary closing conditions, generating gross cash proceeds of \$512 million, plus a DPPA.

In October, we announced the Palliser Divestiture. The sale is expected to close in the fourth quarter, subject to customary closing conditions, generating gross cash proceeds of \$1.3 billion.

## OPERATING RESULTS

Our upstream assets continued to perform well in the three and nine months ended September 30, 2017. Total production increased primarily due to the Acquisition.

### Production Volumes

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	Percent Change	2016	2017	Percent Change	2016
<b>Liquids</b> (barrels per day)						
<b>Oil Sands</b>						
Foster Creek	154,363	109%	73,798	114,632	73%	66,435
Christina Lake	208,131	161%	79,793	154,634	97%	78,321
	<b>362,494</b>	<b>136%</b>	153,591	<b>269,266</b>	<b>86%</b>	144,756
<b>Deep Basin</b>						
Light and Medium Oil	6,494	-%	-	3,208	-%	-
NGLs	26,370	-%	-	13,498	-%	-
	<b>32,864</b>	<b>-%</b>	-	<b>16,706</b>	<b>-%</b>	-
<b>Conventional (Discontinued Operations)</b>						
Heavy Oil	25,549	(9)%	28,096	26,466	(10)%	29,276
Light and Medium Oil	26,947	6%	25,311	26,430	1%	26,200
NGLs	1,201	12%	1,074	1,128	10%	1,027
	<b>53,697</b>	<b>(1)%</b>	54,481	<b>54,024</b>	<b>(4)%</b>	56,503
<b>Total Liquids Production</b> (barrels per day)	<b>449,055</b>	<b>116%</b>	208,072	<b>339,996</b>	<b>69%</b>	201,259
<b>Natural Gas</b> (MMcf per day)						
Oil Sands	6	(67)%	18	11	(35)%	17
Deep Basin	495	-%	-	251	-%	-
Conventional (Discontinued Operations)	350	(6)%	374	351	(8)%	382
<b>Total Natural Gas Production</b> (MMcf per day)	<b>851</b>	<b>117%</b>	392	<b>613</b>	<b>54%</b>	399
<b>Total Production</b> (BOE per day)	<b>590,851</b>	<b>116%</b>	273,405	<b>442,143</b>	<b>65%</b>	267,759

The increase in production at Foster Creek and Christina Lake from May 17, 2017, the closing date of the Acquisition, until September 30, 2017 was 76,127 barrels per day and 104,985 barrels per day, respectively.

Production at Foster Creek increased in the third quarter and on a year-to-date basis compared with 2016 due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues in the third quarter. On a year-to-date basis, production at Foster Creek was also impacted by approximately 3,690 barrels per day due to a planned turnaround completed in the second quarter of 2017. Production at Christina Lake increased in the three and nine months ended September 30, 2017 compared to the same periods in 2016 due to the Acquisition and incremental production volumes from the phase F expansion.

Total liquids production in the Deep Basin for the 137 day period following the Acquisition averaged 33,290 barrels per day.

Our Conventional liquids production decreased in the third quarter and on a year-to-date basis compared with 2016 primarily due to expected natural declines, partially offset by an increase in production associated with the tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

In the third quarter and on a year-to-date basis, our natural gas production rose compared with 2016 due to the Acquisition, partially offset by expected natural declines in our Conventional segment. Natural gas production from the Deep Basin for the 137 days of operations in 2017 was 500 MMcf per day.

### Netbacks

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. 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 write-downs 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.

(\$/BOE)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Sales Price	<b>33.71</b>	29.98	<b>34.89</b>	24.37
Royalties	<b>2.08</b>	1.55	<b>2.37</b>	1.29
Transportation and Blending	<b>4.56</b>	4.51	<b>4.56</b>	4.69
Operating Expenses	<b>8.59</b>	8.92	<b>9.18</b>	9.32
Production and Mineral Taxes	<b>0.08</b>	0.15	<b>0.12</b>	0.12
<b>Netback Excluding Realized Risk Management <sup>(1)</sup></b>	<b>18.40</b>	14.85	<b>18.66</b>	8.95
Realized Risk Management Gain (Loss)	<b>(0.24)</b>	1.63	<b>(0.77)</b>	3.05
<b>Netback Including Realized Risk Management <sup>(1)</sup></b>	<b>18.16</b>	16.48	<b>17.89</b>	12.00

<sup>(1)</sup> Includes results from our Conventional segment, which has been classified as a discontinued operation.

The rise in our average Netback was primarily due to higher liquids sales prices, partially offset by a rise in royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. In the third quarter of 2017, our average Netback rose despite a decline in natural gas prices. On a year-to-date basis, the strengthening of the Canadian dollar compared with 2016 had a negative impact on our sales price of approximately \$0.40 per BOE.

### Refining

In the third quarter, refined product output declined compared with 2016 primarily due to unplanned maintenance at both Refineries in 2017. In addition, lower heavy crude oil volumes were processed due to optimization of the total crude input slate to address narrowing heavy crude oil differentials.

On a year-to-date basis, crude oil runs and refined product output decreased due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2017 compared with 2016, in addition to unplanned maintenance at both Refineries in 2017.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	Percent Change	2016	2017	Percent Change	2016
Crude Oil Runs <sup>(1)</sup> (Mbbbls/d)	<b>462</b>	<b>-%</b>	463	<b>439</b>	<b>(3)%</b>	452
Heavy Crude Oil <sup>(1)</sup>	<b>213</b>	<b>(12)%</b>	241	<b>205</b>	<b>(14)%</b>	237
Refined Product <sup>(1)</sup> (Mbbbls/d)	<b>490</b>	<b>(1)%</b>	494	<b>467</b>	<b>(3)%</b>	479
Crude Utilization <sup>(1)</sup> (percent)	<b>100</b>	<b>(1)%</b>	101	<b>95</b>	<b>(3)%</b>	98

<sup>(1)</sup> Represents 100 percent of the Wood River and Borger refinery operations.

Operating Margin from Refining and Marketing in the three and nine months ended September 30, 2017 was \$211 million and \$284 million, respectively (2016 – \$68 million and \$238 million, respectively). The increases were primarily due to higher average market crack spreads, partially offset by narrowing heavy crude oil differentials.

Further information on the changes in our production volumes, items included in our Netbacks and refining results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management 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, 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,			Q3	Q2	Q3
(US\$/bbl, unless otherwise indicated)	2017	2016	Percent Change	2017	2017	2016
<b>Crude Oil Prices</b>						
<b>Brent</b>						
Average	<b>52.59</b>	43.01	<b>22%</b>	<b>52.18</b>	50.92	46.98
End of Period	<b>57.54</b>	49.06	<b>17%</b>	<b>57.54</b>	47.92	49.06
<b>WTI</b>						
Average	<b>49.47</b>	41.33	<b>20%</b>	<b>48.21</b>	48.29	44.94
End of Period	<b>51.67</b>	48.24	<b>7%</b>	<b>51.67</b>	46.04	48.24
Average Differential Brent-WTI	<b>3.12</b>	1.68	<b>86%</b>	<b>3.97</b>	2.63	2.04
<b>WCS</b>						
Average	<b>37.59</b>	27.65	<b>36%</b>	<b>38.27</b>	37.16	31.44
Average (C\$/bbl)	<b>49.07</b>	36.53	<b>34%</b>	<b>47.96</b>	49.95	41.04
End of Period	<b>40.71</b>	34.97	<b>16%</b>	<b>40.71</b>	36.36	34.97
Average Differential WTI-WCS	<b>11.88</b>	13.68	<b>(13)%</b>	<b>9.94</b>	11.13	13.50
<b>Condensate (C5 @ Edmonton)</b>						
Average <sup>(2)</sup>	<b>49.44</b>	40.51	<b>22%</b>	<b>47.61</b>	48.44	43.07
Average Differential WTI-Condensate (Premium)/Discount	<b>0.03</b>	0.82	<b>(96)%</b>	<b>0.60</b>	(0.15)	1.87
Average Differential WCS-Condensate (Premium)/Discount	<b>(11.85)</b>	(12.86)	<b>(8)%</b>	<b>(9.34)</b>	(11.28)	(11.63)
<b>Mixed Sweet Blend ("MSW" @ Edmonton)</b>						
Average <sup>(3)</sup>	<b>46.57</b>	38.09	<b>22%</b>	<b>45.32</b>	46.03	41.99
End of Period	<b>49.76</b>	45.92	<b>8%</b>	<b>49.76</b>	43.66	45.92
<b>Average Refined Product Prices</b>						
Chicago Regular Unleaded Gasoline ("RUL")	<b>64.48</b>	55.17	<b>17%</b>	<b>66.87</b>	63.44	59.27
Chicago Ultra-low Sulphur Diesel ("ULSD")	<b>65.26</b>	54.60	<b>20%</b>	<b>69.73</b>	62.18	59.86
<b>Refining Margin: Average 3-2-1 Crack Spreads <sup>(4)</sup></b>						
Chicago	<b>15.33</b>	13.77	<b>11%</b>	<b>19.66</b>	14.78	14.58
<b>Average Natural Gas Prices</b>						
AECO (C\$/Mcf)	<b>2.58</b>	1.85	<b>39%</b>	<b>2.04</b>	2.77	2.20
NYMEX (US\$/Mcf)	<b>3.17</b>	2.29	<b>38%</b>	<b>3.00</b>	3.18	2.81
Basis Differential NYMEX-AECO (US\$/Mcf)	<b>1.21</b>	0.89	<b>36%</b>	<b>1.39</b>	1.13	1.13
<b>Foreign Exchange Rate (US\$ per C\$1)</b>						
Average	<b>0.766</b>	0.757	<b>1%</b>	<b>0.798</b>	0.744	0.766

(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks table in the Operating Results section of this MD&A.

(2) The average Canadian dollar condensate benchmark price for the third quarter of 2017 was \$59.66 per barrel (2016 - \$56.23 per barrel) and for the nine months ended September 30, 2017 was \$64.54 per barrel (2016 - \$53.51 per barrel).

(3) The average Canadian dollar MSW benchmark price for the third quarter of 2017 was \$56.79 per barrel (2016 - \$54.82 per barrel) and for the nine months ended September 30, 2017 was \$60.80 per barrel (2016 - \$50.32 per barrel).

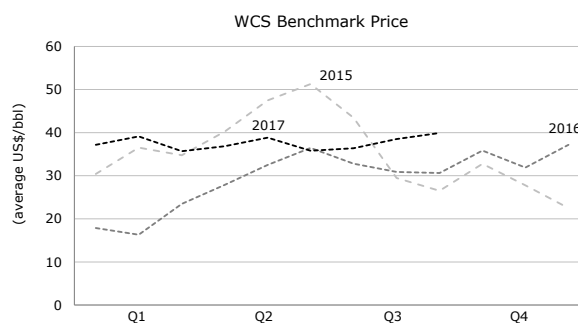
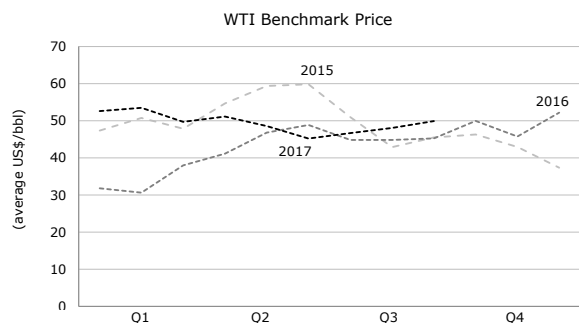
(4) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

### Crude Oil Benchmarks

The average Brent, WTI and Western Canadian Select ("WCS") benchmark prices improved in the nine months ended September 30, 2017 compared with 2016. Compliance with the production cuts outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries ("OPEC") led to wide-spread market expectations of an accelerated return to normal inventory levels. However, without supporting supply and demand drivers, prices continued to be volatile as growing supply from the U.S., unstable supply from Libya and Nigeria, severe weather related incidents, and strong global demand resulted in varying expectations on the pace of crude oil and refined product inventory draws.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI benchmark prices weakened relative to Brent compared with the third quarter of 2016 and on a year-to-date basis due to growing U.S. crude oil supply. In the third quarter of 2017, severe weather related incidents and strong global demand resulted in declines to crude oil and refined product inventory levels.

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 and on a year-to-date basis compared with 2016. WCS strengthened relative to WTI due to a decrease in supply of blended heavy oil as a result of temporary upgrading outages related to a processing facility fire in Alberta. In addition, WCS increased due to higher demand as a result of OPEC's compliance with production cuts and lower supply from Mexico and Colombia.



Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range from approximately 10 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 attributed to transporting the condensate to Edmonton.

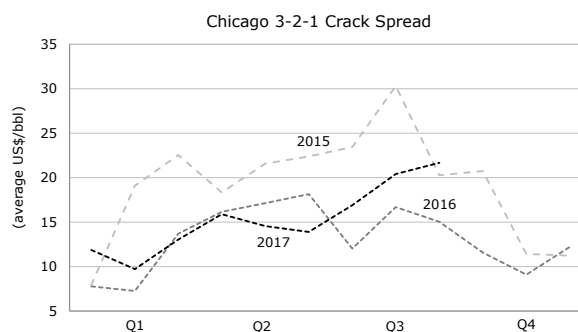
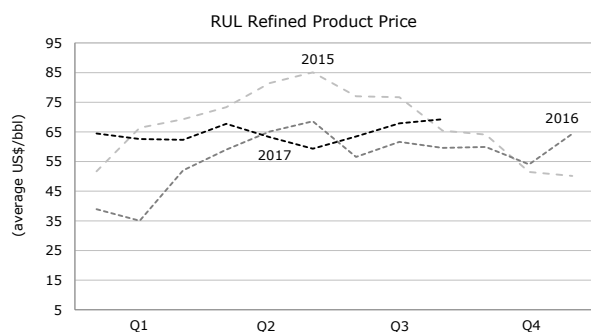
The average WTI-Condensate differential narrowed in the third quarter and on a year-to-date basis compared to 2016 as a result of lower spare capacity on pipelines which increased the cost of transporting condensate to Edmonton.

MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price declined in the third quarter of 2017 compared with the second quarter as a result of synthetic crude oil supply returning to the market after temporary upgrading outages related to a processing facility fire in the second quarter of 2017.

### Refining Benchmarks

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

Average Chicago refined product prices increased in the third quarter of 2017 and on a year-to-date basis primarily due to strong refined product demand and severe weather related events that impacted the refined product output of U.S. Gulf Coast refineries. Average Chicago 3-2-1 crack spreads rose in the three and nine months ended September 30, 2017 compared with 2016 due to the wider Brent-WTI differential, a decline in refined product supplied from the U.S. Gulf Coast, and strong refined product demand. 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 in the third quarter decreased compared with 2016 primarily due to higher natural gas supply in Alberta resulting from extensive pipeline and compressor station maintenance decreasing deliverability to storage facilities and reducing export capability. Average NYMEX natural gas prices increased in 2017 compared with the third quarter of 2016 due to lower levels of natural gas in storage.

On a year-to-date basis, average AECO and NYMEX natural gas prices rose significantly compared with 2016. Natural gas prices strengthened as North American inventory levels declined due to lower production and stronger demand. Production decreased as a result of reduced drilling programs while demand increased from additional capacity to export North American natural gas to foreign markets, partially offset by mild weather and less natural gas used for domestic electricity generation. In addition, natural gas prices in 2016 were negatively impacted by an exceptionally warm winter that resulted in poor heating demand and record-high seasonal North American natural gas storage levels.

### Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, 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, our reported results are higher. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In the third quarter and on a year-to-date basis, the Canadian dollar strengthened relative to the U.S. dollar due to strengthening of the Canadian economy, increases in the Bank of Canada benchmark lending rate and higher commodity prices. The strengthening of the Canadian dollar in the nine months ended September 30, 2017, compared with 2016, had a negative impact of approximately \$155 million on our revenues, including our Conventional segment. As at September 30, 2017, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2016, which resulted in \$715 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

In the three and nine months ended September 30, 2017, the Acquisition and improvements in commodity prices 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		2017			2016				2015	
	September 30, 2017	2016	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
<b>Revenues <sup>(1)</sup></b>	<b>11,964</b>	7,682	<b>4,386</b>	4,037	3,541	3,324	2,945	2,746	1,991	2,601	2,905
<b>Operating Margin <sup>(2)</sup></b>											
Total Operating Margin	<b>2,444</b>	1,172	<b>1,216</b>	778	450	595	487	541	144	357	602
From Continuing Operations	<b>2,023</b>	781	<b>1,099</b>	619	305	442	335	424	22	153	360
<b>Cash From Operating Activities</b>											
Total Cash From Operating Activities	<b>2,159</b>	697	<b>592</b>	1,239	328	164	310	205	182	322	542
From Continuing Operations	<b>1,778</b>	404	<b>481</b>	1,102	195	22	189	121	94	123	366
<b>Adjusted Funds Flow <sup>(3)</sup></b>											
Total Adjusted Funds Flow	<b>2,097</b>	888	<b>982</b>	792	323	535	422	440	26	275	444
From Continuing Operations	<b>1,700</b>	583	<b>867</b>	650	183	382	296	352	(65)	71	266
<b>Operating Earnings (Loss) <sup>(3)</sup></b>											
Total Operating Earnings (Loss)	<b>699</b>	(698)	<b>340</b>	398	(39)	321	(236)	(39)	(423)	(438)	(28)
Per Share – Diluted (\$)	<b>0.66</b>	(0.84)	<b>0.28</b>	0.36	(0.05)	0.39	(0.28)	(0.05)	(0.51)	(0.53)	(0.03)
From Continuing Operations	<b>558</b>	(312)	<b>253</b>	344	(39)	21	(40)	(3)	(269)	(245)	(23)
Per Share – Diluted (\$)	<b>0.53</b>	(0.37)	<b>0.21</b>	0.31	(0.05)	0.03	(0.05)	-	(0.32)	(0.29)	(0.03)
<b>Net Earnings (Loss) From Continuing Operations</b>	<b>3,080</b>	(250)	<b>288</b>	2,581	211	(209)	(55)	(231)	36	(448)	1,806
Per Share – Basic and Diluted (\$)	<b>2.91</b>	(0.30)	<b>0.23</b>	2.32	0.25	(0.25)	(0.07)	(0.28)	0.04	(0.54)	2.17
<b>Net Earnings (Loss)</b>	<b>2,782</b>	(636)	<b>(69)</b>	2,640	211	91	(251)	(267)	(118)	(641)	1,801
Per Share – Basic and Diluted (\$)	<b>2.62</b>	(0.76)	<b>(0.06)</b>	2.37	0.25	0.11	(0.30)	(0.32)	(0.14)	(0.77)	2.16
<b>Capital Investment <sup>(4)</sup></b>	<b>1,078</b>	767	<b>438</b>	327	313	259	208	236	323	428	400
<b>Free Funds Flow <sup>(3)</sup></b>	<b>1,019</b>	121	<b>544</b>	465	10	276	214	204	(297)	(153)	44
<b>Dividends</b>											
Cash Dividends	<b>164</b>	124	<b>62</b>	61	41	42	41	42	41	132	133
Per Share (\$)	<b>0.15</b>	0.15	<b>0.05</b>	0.05	0.05	0.05	0.05	0.05	0.05	0.16	0.16

(1) Excludes revenues from discontinued operations. For the three and nine months ended September 30, 2017, revenues related to discontinued operations were \$286 million and \$946 million, respectively (2016 – \$295 million and \$810 million, respectively).

(2) Additional subtotal found in Note 1 and Note 8 of the interim Consolidated Financial Statements and defined in this MD&A.

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

(4) Includes expenditures on Property, Plant and Equipment ("PP&E"), Exploration and Evaluation ("E&E") assets, and assets held for sale.

## Revenues

(\$ millions)	Three Months Ended	Nine Months Ended
<b>Revenues for the Periods Ended September 30, 2016</b>	<b>2,945</b>	<b>7,682</b>
Increase (Decrease) due to:		
Oil Sands	1,367	2,856
Deep Basin	187	303
Refining and Marketing	(84)	1,200
Corporate and Eliminations	(29)	(77)
<b>Revenues for the Periods Ended September 30, 2017</b>	<b>4,386</b>	<b>11,964</b>

Combined upstream revenues, excluding revenues from our Conventional segment, rose significantly in the third quarter and on a year-to-date basis, compared with 2016. The increase was primarily related to a rise in sales volumes due to the Acquisition and the incremental volumes from the oil sands expansion phases and higher crude oil commodity prices. These increases were partially offset by higher royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. Conventional revenues have been reported in net earnings from discontinued operations and are discussed below.

Revenues from our Refining and Marketing segment in the third quarter of 2017 decreased by four percent. Refining revenues rose compared with 2016 primarily due to an increase in refined product pricing, partially offset by a decline in refined product output and the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group decreased significantly in the three months ended September 30, 2017 compared with 2016 primarily due to a decrease in purchased products and lower crude oil and natural gas sales prices.

On a year-to-date basis, Refining and Marketing revenues increased 20 percent. Refining revenues rose due to higher refined product pricing, consistent with the rise in average Chicago refined product benchmark prices, partially offset by decreased refined product output and the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group increased in the nine months ended September 30, 2017 compared with 2016 due to higher crude oil and natural gas sales prices and an increase in purchased crude oil and condensate volumes, partially offset by a decline in natural gas volumes.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

In the second quarter of 2017, our Conventional segment was classified as a discontinued operation as we intend to divest all of our legacy Conventional assets. For the three and nine months ended September 30, 2017, Conventional revenues were \$286 million and \$946 million, respectively (2016 - \$295 million and \$810 million, respectively). Revenues declined slightly in the third quarter of 2017 due to lower natural gas prices, a rise in royalties, and the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by higher crude oil prices. On a year-to-date basis, the increase in revenues compared with 2016 was primarily due to higher commodity prices, partially offset by a rise in royalties and a decline in sales volumes.

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

### Total Operating Margin

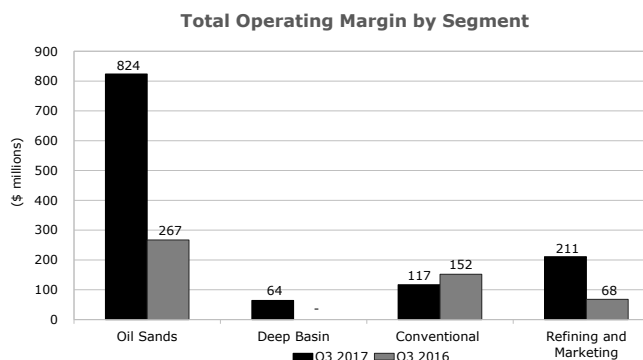
(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Revenues</b>	<b>4,790</b>	3,329	<b>13,232</b>	8,737
(Add) Deduct:				
Purchased Product	1,782	2,004	6,295	5,144
Transportation and Blending	1,132	473	2,692	1,364
Operating Expenses	644	402	1,692	1,247
Production and Mineral Taxes	4	4	14	9
Realized (Gain) Loss on Risk Management Activities	12	(41)	95	(199)
<b>Total Operating Margin <sup>(1)</sup></b>	<b>1,216</b>	487	<b>2,444</b>	1,172

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

### Three Months Ended September 30, 2017 Compared With September 30, 2016

Total Operating Margin more than doubled in the third quarter of 2017 compared with 2016 primarily due to:

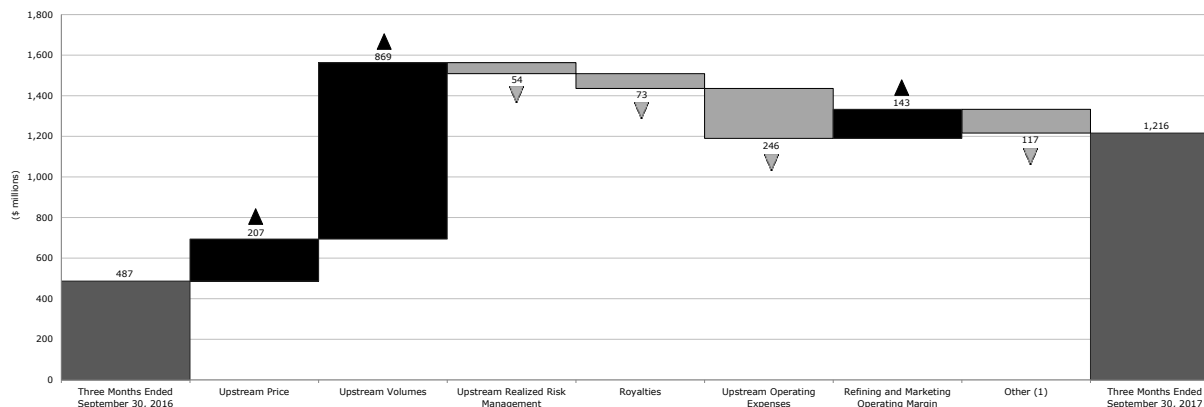
- A significant increase in our liquids and natural gas sales volumes primarily related to the Acquisition and our oil sands expansion phases;
- A rise in our average liquids sales price due to improved benchmark prices; and
- A higher Operating Margin from Refining and Marketing primarily due to an increase in average market crack spreads and a rise in margins on the sale of our secondary products, partially offset by narrowing heavy crude oil differentials, and a strengthening of the Canadian dollar relative to the U.S. dollar.



These increases in Operating Margin were partially offset by:

- A rise in transportation and blending expenses primarily due to higher blending costs related to an increase in condensate volumes required for blending our increased oil sands production along with higher condensate prices;
- An increase in operating expenses primarily due to the Acquisition;
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), an increase in sales volumes due to the Acquisition, and a rise in our liquids sales price;
- Realized risk management losses of \$12 million, associated with our upstream assets, compared with gains of \$42 million in the third quarter of 2016; and
- A decline in our natural gas sales price from 2016.

#### Total Operating Margin Variance



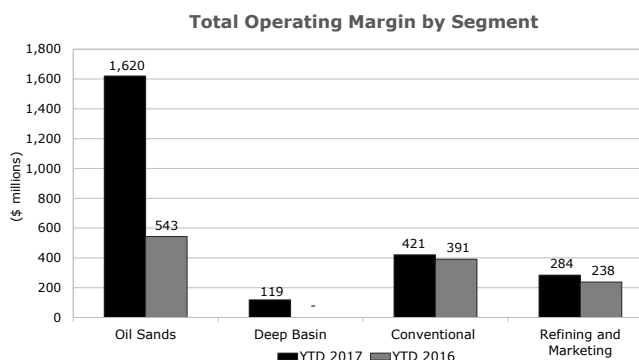
(1) Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.



## Nine Months Ended September 30, 2017 Compared With September 30, 2016

Operating Margin more than doubled in the nine months ended September 30, 2017 compared with 2016 primarily due to:

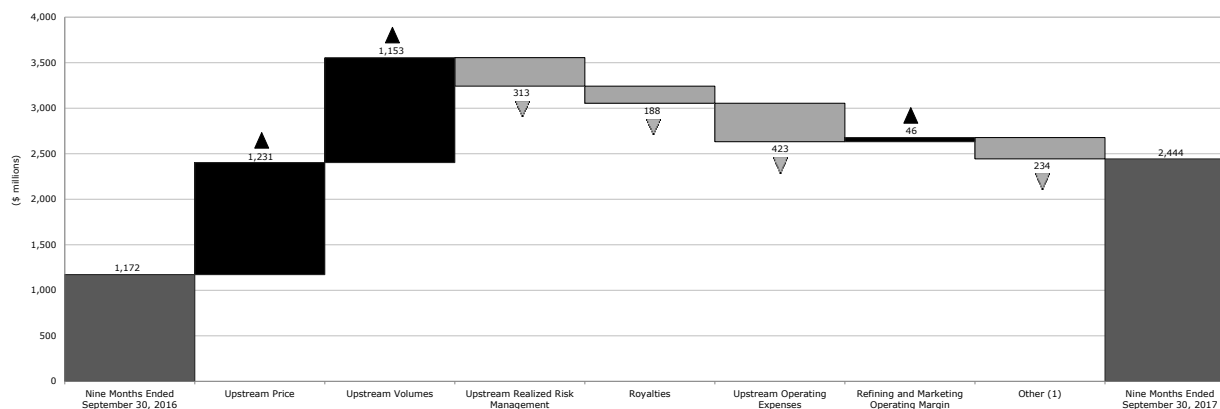
- A rise in our average liquids and natural gas sales prices due to improved benchmark prices;
- An increase in our liquids sales volumes primarily related to the Acquisition and our 2016 oil sand expansion phases, and a rise in our natural gas sales volumes primarily due to the acquired Deep Basin Assets; and
- A higher Operating Margin from Refining and Marketing due to an increase in average market crack spreads, a rise in margins on the sale of our secondary products, and lower realized risk management losses, partially offset by narrowing heavy crude oil differentials, lower crude utilization rates, and an increase in operating costs.



These increases to Operating Margin were partially offset by:

- A rise in transportation and blending expenses primarily due to higher blending costs, related to an increase in condensate volumes required for blending our increased oil sands production along with higher condensate prices;
- An increase in operating expenses primarily due to the Acquisition and higher fuel costs related to the increase in natural gas pricing;
- Realized risk management losses of \$91 million, associated with our upstream assets, compared with gains of \$222 million in 2016; and
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), a rise in our liquids sales price, and an increase in sales volumes due to the Acquisition.

### Total Operating Margin 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 can be found in the Reportable Segments section of this MD&A.

### Operating Margin From Continuing Operations

Operating Margin From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Revenues</b>	<b>4,504</b>	3,034	<b>12,286</b>	7,927
(Add) Deduct:				
Purchased Product	<b>1,782</b>	2,004	<b>6,295</b>	5,144
Transportation and Blending	<b>1,088</b>	429	<b>2,543</b>	1,228
Operating Expenses	<b>526</b>	300	<b>1,349</b>	916
Realized (Gain) Loss on Risk Management Activities	<b>9</b>	(34)	<b>76</b>	(142)
<b>Operating Margin From Continuing Operations</b>	<b>1,099</b>	335	<b>2,023</b>	781

### Cash From Operating Activities and Adjusted Funds Flow

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

### Total Cash From Operating Activities and Adjusted Funds Flow

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Cash From Operating Activities <sup>(1)</sup></b>	<b>592</b>	310	<b>2,159</b>	697
(Add) Deduct:				
Net Change in Other Assets and Liabilities	<b>(19)</b>	(13)	<b>(75)</b>	(59)
Net Change in Non-Cash Working Capital	<b>(371)</b>	(99)	<b>137</b>	(132)
<b>Adjusted Funds Flow <sup>(1)</sup></b>	<b>982</b>	422	<b>2,097</b>	888

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

In the third quarter of 2017, Cash From Operating Activities and Adjusted Funds Flow increased primarily as a result of a higher Operating Margin, as discussed above, partially offset by realized foreign exchange losses on working capital compared with realized foreign exchange gains in 2016, a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition, and higher general and administrative expenses.

On a year-to-date basis, Cash From Operating Activities and Adjusted Funds Flow increased compared with 2016 due to a higher Operating Margin, as discussed above, a larger current tax recovery, and a realized risk management gain on foreign exchange contracts due to hedging activity undertaken to support the Acquisition, partially offset by a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition and an increase in realized foreign exchange losses on working capital items.

The change in non-cash working capital for the three months ended September 30, 2017 was due to a decline in accounts payable, a decrease in income tax payable and an increase in accounts receivable. For the three months ended September 30, 2016, the change in non-cash working capital was due to a decline in accounts payable, a decrease in income tax payable, and a reduction in accounts receivable.

The change in non-cash working capital for the nine months ended September 30, 2017 was primarily due to a decline in accounts receivable and a reduction in inventory, partially offset by a decrease in accounts payable and an increase in income tax receivable. For the nine months ended September 30, 2016, the change in non-cash working capital was primarily due to a rise in inventory and an increase in accounts receivable, partially offset by an increase in accounts payable.

### **Cash From Operating Activities From Continuing Operations and Adjusted Funds Flow From Continuing Operations**

Cash From Operating Activities From Continuing Operations and Adjusted Funds Flow From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

(\$ millions)	Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017	
		2016		2016
<b>Cash From Operating Activities From Continuing Operations</b>	<b>481</b>	189	<b>1,778</b>	404
(Add) Deduct:				
Net Change in Other Assets and Liabilities	(15)	(8)	(59)	(47)
Net Change in Non-Cash Working Capital	(371)	(99)	137	(132)
<b>Adjusted Funds Flow From Continuing Operations</b>	<b>867</b>	296	<b>1,700</b>	583

### **Operating Earnings (Loss)**

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

### **Total Operating Earnings**

(\$ millions)	Three Months Ended September 30, 2017		Nine Months Ended September 30, 2017	
		2016		2016
<b>Earnings (Loss), Before Income Tax <sup>(1)</sup></b>	<b>(311)</b>	(406)	<b>3,291</b>	(1,089)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss <sup>(2)</sup>	486	7	75	440
Non-Operating Unrealized Foreign Exchange (Gain) Loss <sup>(3)</sup>	(367)	52	(702)	(343)
Revaluation (Gain)	-	-	(2,524)	-
(Gain) Loss on Divestiture of Assets	(1)	5	-	6
Loss on Discontinuance	603	-	603	-
<b>Operating Earnings (Loss), Before Income Tax</b>	<b>410</b>	(342)	<b>743</b>	(986)
Income Tax Expense (Recovery)	70	(106)	44	(288)
<b>Operating Earnings (Loss)</b>	<b>340</b>	(236)	<b>699</b>	(698)

(1) Includes discontinued operations.

(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 increased in the three months ended September 30, 2017 compared with 2016 primarily due to higher Cash from Operating Activities and Adjusted Funds Flow, as discussed above, a decrease in depreciation, depletion and amortization ("DD&A"), higher unrealized foreign exchange gains on operating items, and the re-measurement of the contingent payment.

Operating Earnings increased in the nine months ended September 30, 2017 compared with 2016 primarily due to higher Cash from Operating Activities and Adjusted Funds Flow, as discussed above, a decrease in DD&A, unrealized foreign exchange gains on operating items compared with unrealized foreign exchange losses in 2016 and the re-measurement of the contingent payment.

### Operating Earnings From Continuing Operations

Operating Earnings From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Earnings (Loss) From Continuing Operations, Before Income Tax</b>	<b>178</b>	(121)	<b>3,701</b>	(527)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss <sup>(1)</sup>	<b>486</b>	7	<b>75</b>	440
Non-Operating Unrealized Foreign Exchange (Gain) Loss <sup>(2)</sup>	<b>(367)</b>	52	<b>(702)</b>	(343)
Revaluation (Gain)	-	-	<b>(2,524)</b>	-
(Gain) Loss on Divestiture of Assets	<b>(1)</b>	5	-	6
<b>Operating Earnings (Loss) From Continuing Operations, Before Income Tax</b>	<b>296</b>	(57)	<b>550</b>	(424)
Income Tax Expense (Recovery)	<b>43</b>	(17)	<b>(8)</b>	(112)
<b>Operating Earnings (Loss) From Continuing Operations</b>	<b>253</b>	(40)	<b>558</b>	(312)

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

(2) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

### Net Earnings

(\$ millions)	Three Months Ended	Nine Months Ended
<b>Net Earnings (Loss) for the Periods Ended September 30, 2016</b>	<b>(251)</b>	<b>(636)</b>
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	<b>764</b>	<b>1,242</b>
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	<b>(479)</b>	<b>365</b>
Unrealized Foreign Exchange Gain (Loss)	<b>490</b>	<b>567</b>
Revaluation Gain	-	<b>2,524</b>
Re-measurement of Contingent Payment	<b>43</b>	<b>109</b>
Gain (Loss) on Divestiture of Assets	<b>6</b>	<b>6</b>
Expenses <sup>(1)</sup>	<b>(220)</b>	<b>(97)</b>
DD&A	<b>(305)</b>	<b>(489)</b>
Exploration Expense	-	<b>1</b>
Income Tax Recovery (Expense)	<b>44</b>	<b>(898)</b>
Net Earnings (Loss) From Discontinued Operations	<b>(161)</b>	<b>88</b>
<b>Net Earnings (Loss) for the Periods Ended September 30, 2017</b>	<b>(69)</b>	<b>2,782</b>

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

Net loss for the three and nine months ended September 30, 2017 includes a \$440 million after-tax loss on the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project. Net loss in the third quarter decreased compared with 2016 primarily due to:

- Higher Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of \$367 million primarily related to the translation of our U.S. dollar denominated debt compared with unrealized losses of \$52 million in 2016; and
- A deferred income tax recovery compared with an expense in 2016.

These decreases to our net loss were partially offset by unrealized risk management losses of \$486 million compared with \$7 million in the third quarter of 2016.

Net earnings improved significantly for the nine months ended September 30, 2017 primarily due to:

- The revaluation gain of \$2,524 million related to the deemed disposition of our pre-existing interest in FCCL;
- Higher Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of \$702 million compared with \$343 million in 2016; and
- Unrealized risk management losses of \$75 million compared with \$440 million in 2016.

These increases were partially offset by a deferred income tax expense primarily due to the gain on the revaluation of our pre-existing interest in FCCL compared with a recovery in 2016.

## Net Capital Investment

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Oil Sands	273	110	660	476
Deep Basin	64	-	77	-
Conventional	42	41	180	114
Refining and Marketing	38	51	124	156
Corporate and Eliminations	21	6	37	21
<b>Capital Investment</b>	<b>438</b>	208	<b>1,078</b>	767
Acquisitions <sup>(1)</sup>	70	-	18,301	11
Divestitures <sup>(1)</sup>	(943)	(8)	(943)	(8)
<b>Net Capital Investment <sup>(2)</sup></b>	<b>(435)</b>	200	<b>18,436</b>	770

(1) In connection with the Acquisition that was completed in the second quarter of 2017, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3 "Business Combinations" ("IFRS 3"), which is not reflected in the table above. The carrying value of the pre-existing interest was \$9,081 million and the estimated fair value was \$11,605 million as at May 17, 2017.

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

Capital investment in the three and nine months ended September 30, 2017 increased \$230 million and \$311 million, respectively, compared with 2016. On a year-to-date basis in 2017, Oil Sands capital investment focused on sustaining capital related to existing production; Christina Lake expansion phase G; and stratigraphic test wells to determine pad placement for sustaining wells, near-term expansion phases, and progression of certain emerging assets. Deep Basin capital investment for the 137 days of ownership related to asset development planning and the commencement of our horizontal drilling program, targeting liquids rich gas within the Deep Basin corridor. In 2017, Conventional capital investment focused on sustaining capital and the tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of our Conventional assets. Capital investment in the Refining and Marketing segment related to capital maintenance and reliability work.

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

## Capital Investment Decisions

In the short-term, we are acutely focused on completing the divestiture of our legacy Conventional assets in order to deleverage our balance sheet. To date, we have announced divestitures totaling approximately \$2.8 billion in gross proceeds. We closed the first divestiture, Pelican Lake and the adjacent Grand Rapids project, in the third quarter of 2017 and have used the net proceeds to pay down the committed Bridge Facility. In addition to our commitment to reduce our debt, we are actively identifying cost savings opportunities.

With balance sheet leverage more in line with our strategy, our long-term disciplined approach to capital allocation includes prioritizing our uses of cash in the following manner:

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

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

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Adjusted Funds Flow <sup>(1)</sup>	982	422	2,097	888
Capital Investment (Sustaining and Growth)	438	208	1,078	767
Free Funds Flow <sup>(1) (2)</sup>	544	214	1,019	121
Cash Dividends	62	41	164	124
	<b>482</b>	173	<b>855</b>	(3)

(1) Includes discontinued operations.

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

For the nine months ended September 30, 2016, capital investment and cash dividends in excess of Adjusted Funds Flow was funded through our cash balance on hand.

We updated our 2017 guidance estimates upon further review of our capital program to reflect ongoing cost savings, efficiency improvements, divestiture activities, and our continued focus on capital discipline. Capital spend for 2017 is now expected to be between approximately \$1.55 billion and \$1.65 billion, a reduction of six percent from July 26, 2017.

## REPORTABLE SEGMENTS

Our reportable segments are as follows:

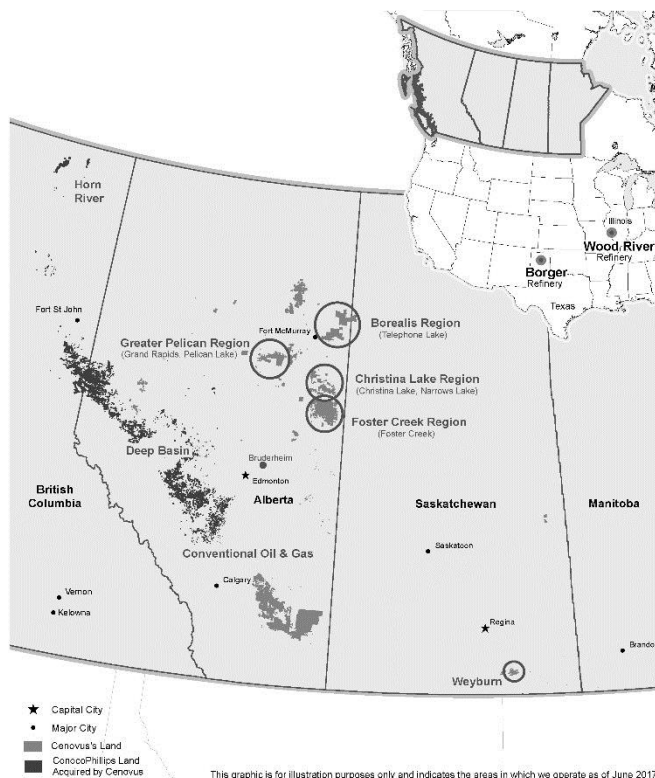
**Oil Sands**, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Telephone Lake. Our interest in certain of our operated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

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

**Conventional**, which has been classified as a discontinued operation as we commenced marketing for sale our Conventional assets. This segment includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the CO<sub>2</sub> enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

**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 relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.



### Revenues by Reportable Segment <sup>(1)</sup>

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Oil Sands <sup>(2)</sup>	2,156	789	4,821	1,965
Deep Basin <sup>(3)</sup>	187	-	303	-
Refining and Marketing	2,161	2,245	7,162	5,962
Corporate and Eliminations	(118)	(89)	(322)	(245)
	<b>4,386</b>	<b>2,945</b>	<b>11,964</b>	<b>7,682</b>

(1) In the second quarter of 2017, we announced our intention to divest the Conventional segment assets. As a result, the Conventional segment was classified as a discontinued operation. For the three and nine months ended September 30, 2017, revenues related to discontinued operations were \$286 million and \$946 million, respectively (2016 - \$295 million and \$810 million, respectively).

(2) Our 2017 results include 137 days of FCCI operations at 100 percent. See the Oil Sands segment section of this MD&A for more details.

(3) Our 2017 results include 137 days of operations from the Deep Basin Assets. See the Deep Basin segment section of this MD&A for more details.

## OIL SANDS

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

Significant developments in our Oil Sands segment in the third quarter of 2017 compared with 2016 include:

- More than doubling our crude oil production primarily due to the Acquisition and incremental production volumes from Christina Lake phase F and Foster Creek phase G, both of which started-up in the second half of 2016;
- Crude oil netbacks, excluding realized risk management activities, of \$24.73 per barrel, a 55 percent increase from the third quarter of 2016; and
- Generating Operating Margin net of capital investment of \$551 million, an increase of \$394 million.

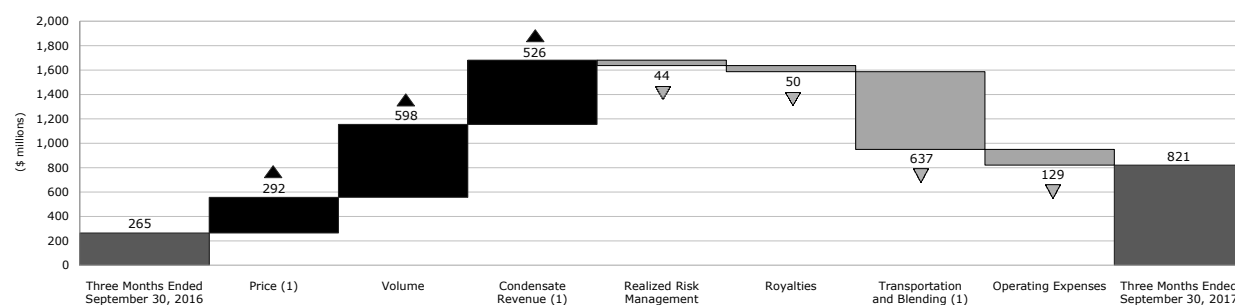
### Oil Sands – Crude Oil

#### Three Months Ended September 30, 2017 Compared With September 30, 2016

##### Financial Results

(\$ millions)	Three Months Ended September 30, 2017	2016
<b>Gross Sales</b>	<b>2,204</b>	788
Less: Royalties	54	4
<b>Revenues</b>	<b>2,150</b>	784
<b>Expenses</b>		
Transportation and Blending	1,066	429
Operating	254	125
(Gain) Loss on Risk Management	9	(35)
<b>Operating Margin</b>	<b>821</b>	265
Capital Investment	270	107
<b>Operating Margin Net of Related Capital Investment</b>	<b>551</b>	158

##### 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 2017, our average crude oil sales price increased to \$40.02 per barrel (2016 – \$31.30 per barrel). The rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend (“CDB”) benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US\$1.47 per barrel (2016 – discount of US\$2.05 per barrel).

Our crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate increases relative to the price of blended crude oil, our bitumen sales price decreases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark

price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

#### *Production Volumes*

(barrels per day)	Three Months Ended September 30,		
	2017	Percent Change	2016
Foster Creek	154,363	109%	73,798
Christina Lake	208,131	161%	79,793
	<b>362,494</b>	<b>136%</b>	153,591

Production at Foster Creek was higher compared with 2016 primarily due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues which were resolved by the end of the quarter.

Production from Christina Lake increased in the three months ended September 30, 2017 compared with 2016 primarily due to the Acquisition and incremental production volumes from the phase F expansion.

#### *Condensate*

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential during the third quarter of 2017, the proportion of the cost of condensate recovered increased. The amount of condensate used increased as a result of the Acquisition.

#### *Royalties*

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

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. In 2017, our royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2016.

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

#### *Effective Royalty Rates*

(percent)	Three Months Ended September 30,	
	2017	2016
Foster Creek	9.1	0.8
Christina Lake	1.6	1.6

Royalties increased \$50 million in the third quarter compared with 2016, primarily due to a higher WTI benchmark price (which determines the royalty rate), rise in sales volumes, and an increase in crude oil sales prices. As noted above, the Foster Creek royalty calculation was based on net profits as compared with a calculation based on gross revenues for 2016, resulting in a significant increase in the royalty rate.

## **Expenses**

#### *Transportation and Blending*

Transportation and blending costs increased \$637 million. Blending costs increased due to a rise in condensate volumes required for our increased production and higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price in the third quarter of 2017, 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 higher sales volumes as a result of the Acquisition and incremental production volumes from the expansion phases. To help ensure adequate capacity for our expected production growth, we have capacity commitments in excess of our current production. Production growth is expected to reduce our per-barrel transportation costs.

In addition, rail costs rose as a result of moving higher volumes by rail and transporting more volumes longer distances to U.S. markets. We transported an average of 9,958 barrels per day of crude oil by rail (2016 – 7,573 barrels per day).

#### Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs rose due to an increase in rail costs related to higher volumes shipped to the U.S. by unit trains, partially offset by an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs.

At Christina Lake, transportation costs decreased primarily due to a revision to prior period toll charges and an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs.

#### Operating

Primary drivers of our operating expenses for the third quarter of 2017 were workforce costs, fuel, chemical costs, workovers and repairs and maintenance. Total operating expenses increased \$129 million primarily due to the Acquisition, partially offset by a decline in fuel costs associated with a decrease in the natural gas price.

#### Per-unit Operating Expenses

(\$/bbl)	Three Months Ended September 30,		
	2017	Percent Change	2016
<b>Foster Creek</b>			
Fuel	2.10	(14)%	2.44
Non-fuel	7.43	3%	7.19
Total	9.53	(1)%	9.63
<b>Christina Lake</b>			
Fuel	1.78	(17)%	2.14
Non-fuel	4.30	(23)%	5.58
Total	6.08	(21)%	7.72
<b>Total</b>	<b>7.58</b>	<b>(12)%</b>	8.65

At Foster Creek, per-barrel fuel costs decreased compared with 2016 primarily due to lower natural gas prices. Per-barrel non-fuel operating expenses increased primarily due to increased workover activities due to pump changes, partially offset by an increase in production.

At Christina Lake, fuel costs decreased on a per-barrel basis in 2017 primarily due to lower fuel consumption. Non-fuel per-barrel operating expenses declined primarily due to higher production, partially offset by higher workforce and chemicals costs associated with the phase F expansion, increased workover activities due to pump changes, and increased repairs and maintenance activities.

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

(\$/bbl)	Foster Creek		Christina Lake	
	Three Months Ended September 30,			
	2017	2016	2017	2016
Sales Price	41.57	33.61	38.84	29.11
Royalties	2.98	0.19	0.55	0.41
Transportation and Blending	8.68	8.38	4.14	4.49
Operating Expenses	9.53	9.63	6.08	7.72
<b>Netback Excluding Realized Risk Management</b>	<b>20.38</b>	15.41	<b>28.07</b>	16.49
Realized Risk Management Gain (Loss)	(0.13)	2.37	(0.40)	2.38
<b>Netback Including Realized Risk Management</b>	<b>20.25</b>	17.78	<b>27.67</b>	18.87

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

#### Risk Management

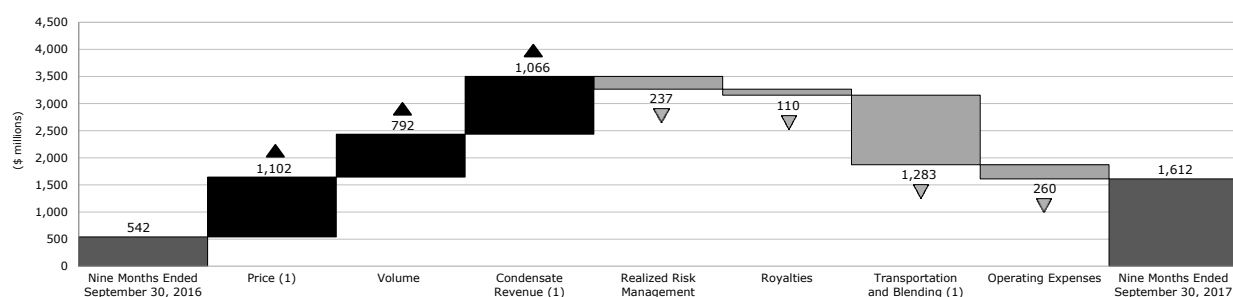
Risk management activities in the third quarter of 2017 resulted in realized losses of \$9 million (2016 – realized gains of \$35 million), consistent with average benchmark prices exceeding our contract prices.

## Nine Months Ended September 30, 2017 Compared With September 30, 2016

### Financial Results

(\$ millions)	Nine Months Ended September 30,	
	2017	2016
<b>Gross Sales</b>	<b>4,920</b>	1,960
Less: Royalties	<b>117</b>	7
<b>Revenues</b>	<b>4,803</b>	1,953
<b>Expenses</b>		
Transportation and Blending	<b>2,511</b>	1,228
Operating	<b>608</b>	348
(Gain) Loss on Risk Management	<b>72</b>	(165)
<b>Operating Margin</b>	<b>1,612</b>	542
Capital Investment	<b>654</b>	472
<b>Operating Margin Net of Related Capital Investment</b>	<b>958</b>	70

### 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, 2017, our average crude oil sales price increased significantly to \$39.52 per barrel (2016 – \$24.28 per barrel). The significant rise in our crude oil price was consistent with the increase in the WCS and CDB benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US\$1.60 per barrel (2016 – discount of US\$2.22 per barrel).

#### Production Volumes

(barrels per day)	Nine Months Ended September 30,	
	2017	Percent Change
Foster Creek	<b>114,632</b>	<b>73%</b>
Christina Lake	<b>154,634</b>	<b>97%</b>
	<b>269,266</b>	<b>86%</b>
		144,756

Production at Foster Creek was higher compared with 2016 due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues and a 20-day planned turnaround which reduced average production by 3,690 barrels per day. The planned turnaround was the largest scale turnaround executed to date at Foster Creek.

Production from Christina Lake increased in the nine months ended September 30, 2017 primarily due to the Acquisition and incremental production volumes from the phase F expansion.

The year-to-date increase in production volumes at Foster Creek and Christina Lake due to the Acquisition was 38,203 barrels per day and 52,685 barrels per day, respectively.

## Royalties

### Effective Royalty Rates

(percent)	Nine Months Ended September 30,	
	2017	2016
Foster Creek	8.4	0.5
Christina Lake	2.1	1.4

Royalties increased \$110 million. Royalties at Foster Creek increased primarily due to a higher WTI benchmark price (which determines the royalty rate). The royalty calculation was based on net profits as compared with a calculation based on gross revenues for 2016, resulting in a significant increase in the royalty rate. In 2016, the low royalty rate was primarily due to low crude oil sales prices and a true-up of the 2015 royalty calculation.

Christina Lake royalties increased in 2017 primarily as a result of a rise in the WTI benchmark price (which determines the royalty rate), higher sales prices and an increase in sales volumes.

## Expenses

### Transportation and Blending

Transportation and blending costs increased \$1,283 million. Blending costs increased due to a rise in condensate volumes required for our increased production along with higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price in the nine months ended September 30, 2017, 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 higher sales volumes related to the incremental production volumes from the Acquisition and expansion phases.

In addition, rail costs rose as a result of moving higher volumes by rail over longer distances to U.S. markets. We transported an average of 7,842 barrels per day of crude oil by rail (2016 – 5,106 barrels per day).

### Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs declined primarily due to an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs, partially offset by an increase in rail costs related to an increase in volumes shipped to the U.S. by unit trains.

At Christina Lake, transportation costs decreased primarily due to an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs, and a revision to prior period toll charges.

### Operating

Primary drivers of our operating expenses in the nine months ended September 30, 2017 were workforce costs, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses increased \$260 million primarily due to the Acquisition, higher fuel costs with the rise in natural gas prices, additional repairs and maintenance, and fluid, waste handling and trucking costs related to the turnaround at Foster Creek and increased workforce and chemical costs associated with the phase F expansion at Christina Lake.

### Per-unit Operating Expenses

(\$/bbl)	Nine Months Ended September 30,		
	2017	Percent Change	2016
<b>Foster Creek</b>			
Fuel	2.53	15%	2.20
Non-fuel	7.96	(4)%	8.32
Total	10.49	-%	10.52
<b>Christina Lake</b>			
Fuel	2.14	16%	1.85
Non-fuel	4.66	(14)%	5.39
Total	6.80	(6)%	7.24
<b>Total</b>	<b>8.40</b>	<b>(4)%</b>	<b>8.74</b>

At Foster Creek, per-barrel fuel costs increased primarily due to the rise in natural gas prices. Per-barrel non-fuel operating expenses declined primarily due to higher production, partially offset by higher repairs and maintenance, and fluid, waste handling and trucking costs related to turnaround activities, and an increase in workover costs due to pump changes.

At Christina Lake, fuel costs rose on a per-barrel basis due to a rise in natural gas prices, partially offset by a decrease in fuel consumption. Per-barrel non-fuel operating expenses decreased primarily due to higher production, partially offset by increased workforce and chemical costs associated with the phase F expansion, and higher repairs and maintenance activities.

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

(\$/bbl)	Foster Creek		Christina Lake	
	Nine Months Ended September 30,			
	2017	2016	2017	2016
Sales Price	42.22	26.97	37.47	22.01
Royalties	2.80	0.10	0.71	0.25
Transportation and Blending	9.01	9.43	4.12	4.89
Operating Expenses	10.49	10.52	6.80	7.24
<b>Netback Excluding Realized Risk Management</b>	<b>19.92</b>	6.92	<b>25.84</b>	9.63
Realized Risk Management Gain (Loss)	(1.05)	4.37	(0.96)	3.95
<b>Netback Including Realized Risk Management</b>	<b>18.87</b>	11.29	<b>24.88</b>	13.58

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

### Risk Management

Risk management activities on a year-to-date basis in 2017 resulted in realized losses of \$72 million (2016 – realized gains of \$165 million), consistent with average benchmark prices exceeding our contract prices.

### Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the three and nine months ended September 30, 2017, net of internal usage, was 6 MMcf per day and 11 MMcf per day, respectively (2016 – 18 MMcf per day and 17 MMcf per day, respectively).

Operating Margin from our Oil Sands natural gas production was \$nil in the third quarter of 2017, a decrease of \$3 million compared with 2016, due to lower natural gas sales prices and a decline in natural gas volumes. On a year-to-date basis, the Operating Margin was \$3 million, a decrease of \$1 million compared with 2016, due to lower natural gas volumes, partially offset by higher natural gas sales prices.

### Oil Sands – Capital Investment

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Foster Creek	122	54	312	211
Christina Lake	132	47	272	222
	254	101	584	433
Narrows Lake	3	1	11	6
Telephone Lake	3	3	32	13
Grand Rapids	-	-	1	5
Other <sup>(1)</sup>	13	5	32	19
<b>Capital Investment <sup>(2)</sup></b>	<b>273</b>	110	<b>660</b>	476

(1) Includes new resource plays and Athabasca natural gas.

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

### Existing Projects

Capital investment reflects our 100 percent ownership of FCCL from May 17, 2017 forward. Capital investment at Foster Creek in 2017 focused on sustaining capital related to existing production and stratigraphic test wells. In 2016, capital investment was low due to spending reductions in response to the low commodity price environment. Capital was also invested in 2016 to complete Foster Creek phase G.

In 2017, Christina Lake capital investment related to sustaining capital related to existing production, the phase G expansion and stratigraphic test wells. In 2016, capital was focused on sustaining capital related to existing production, the completion of expansion phase F and stratigraphic test wells.

Capital investment at Narrows Lake on a year-to-date basis in 2017 related to drilling of stratigraphic test wells to further progress the project.

### Emerging Projects

In 2017, Telephone Lake capital investment concentrated on the drilling of stratigraphic test wells to further assess the project. In 2016, spending was reduced in response to the low commodity price environment and focused on front-end engineering work for the central processing facility.

## Drilling Activity

Nine Months Ended September 30,	Gross Stratigraphic Test Wells		Gross Production Wells <sup>(1)</sup>	
	2017	2016	2017	2016
Foster Creek	93	95	25	18
Christina Lake	105	97	8	24
	198	192	33	42
Narrows Lake	2	-	-	-
Telephone Lake	13	-	-	-
Other	1	5	-	-
	214	197	33	42

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

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

### Future Capital Investment

We updated our 2017 guidance estimates upon further review of our capital program. Our revised full-year 2017 Oil Sands capital investment is forecast to be between \$945 million and \$1,015 million. Guidance has decreased from July 26, 2017 by approximately eight percent to reflect ongoing cost savings, efficiency improvements and our continued focus on capital discipline.

Foster Creek is currently producing from phases A through G. Capital investment for 2017 is forecast to be between \$450 million and \$475 million. We plan to continue focusing on sustaining capital related to existing production and to progress phase H, a potential 40,000 barrels per day phase, towards being sanction ready.

Christina Lake is producing from phases A through F. Capital investment for 2017 is forecast to be between \$425 million and \$450 million, focused on sustaining capital and construction of the phase G expansion. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, is progressing well and remains on track. Phase G is expected to start producing in the second half of 2019.

Capital investment at our Narrows Lake and new resource plays in 2017 is forecast to be between \$70 million and \$90 million, focusing on stratigraphic test well programs at Telephone Lake and engineering and equipment preservation related to the suspension of construction at Narrows Lake.

### DD&A and Exploration Expense

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 following calculation illustrates how the implied depletion rate for our total upstream assets could be determined using the reported consolidated data and includes our Conventional segment, which has been classified as held for sale. Once classified as held for sale depletion stops.

(\$ millions, unless otherwise indicated)	As at December 31, 2016
Upstream Property, Plant and Equipment Carrying Value	11,878
Estimated Future Development Capital	18,378
Total Estimated Upstream Cost Base	30,256
Total Proved Reserves (MMBOE)	2,667
<b>Implied Depletion Rate</b> (\$/BOE)	<b>11.34</b>

While this illustrates the calculation of the implied depletion rate, our depletion rates result in a total average rate ranging between \$9.55 to \$10.00 per BOE. Amounts related to assets under construction and discontinued operations which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the December 31, 2016 Consolidated Financial Statements.

In the three and nine months ended September 30, 2017, Oil Sands DD&A increased \$212 million and \$351 million, respectively, from 2016. The increase was due to higher sales volumes primarily due to the Acquisition. The average depletion rate on a year-to-date basis in 2017 was approximately \$11.24 per barrel compared with \$11.55 per barrel in 2016. Our DD&A rate decreased due to proved reserves additions and lower

future development costs. The decrease in DD&A rates was partially offset by an increase in the carrying value of our assets due to the re-measurement of our pre-existing interest in FCCL and the acquisition of the additional 50 percent interest.

Future development costs declined due to cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs and increased well pair spacing. This decline was partially offset by an increase in costs related to the expansion of the development area and inclusion of phase G costs at Christina Lake.

For the three and nine months ended September 30, 2017, we recorded exploration expense of \$1 million (2016 – \$1 million and \$2 million, respectively).

#### Assets and Liabilities Held for Sale

On September 29, 2017, we closed the sale of our Pelican Lake assets, including the adjacent Grand Rapids project.

#### DEEP BASIN

On May 17, 2017, we acquired the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets including undeveloped land, exploration and production assets, and related infrastructure in Alberta and British Columbia. Our Deep Basin Assets include approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, with an average 70 percent working interest. In addition, the Deep Basin Assets include interests in numerous natural gas processing plants with an estimated net processing capacity of 1.4 Bcf per day. The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. Deep Basin production is expected to provide an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations, as well as NGLs that could be used as inputs for future solvent aided oil sands projects.

The safe and efficient integration of the Deep Basin Assets continues to be a top priority for Cenovus. We are committed to ensuring strong stakeholder and community relations as we establish ourselves as a new operator in the Deep Basin area.

Significant developments that impacted our Deep Basin segment in the third quarter of 2017 included:

- Total capital investment of \$64 million related to the drilling of 10 horizontal production wells targeting liquids rich gas, the completion of four wells, and the tie-in of three wells;
- Netbacks of \$5.34 per BOE;
- Total production averaging 115,301 BOE per day;
- Revenues of \$187 million; and
- Total operating costs of \$101 million or \$9.00 per BOE.

#### Financial Results

(\$ millions)	Three Months Ended September 30, 2017	May 17 – September 30, 2017
<b>Gross Sales</b>	200	324
Less: Royalties	13	21
<b>Revenues</b>	187	303
<b>Expenses</b>		
Transportation and Blending	22	32
Operating	101	152
<b>Operating Margin</b>	64	119
Capital Investment	64	77
<b>Operating Margin Net of Related Capital Investment</b>	-	42

#### Revenues

Price

	Three Months Ended September 30, 2017	May 17 – September 30, 2017
NGLs (\$/bbl)	30.78	29.57
Light and Medium Oil (\$/bbl)	52.54	55.64
Natural Gas (\$/mcf)	1.77	2.15
<b>Total Oil Equivalent (\$/BOE)</b>	17.61	19.07

Our Deep Basin Assets produce a variety of products from natural gas, condensate, other NGLs (including ethane, propane, butane and pentane) and light and medium oil.

For the three and nine months ended September 30, 2017, revenues include \$13 million and \$19 million, respectively, of processing fee revenue related to our interests in natural gas processing facilities. We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

#### Production Volumes

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
<b>Liquids</b>		
NGLs (barrels per day)	26,370	13,498
Light and Medium Oil (barrels per day)	6,494	3,208
	<b>32,864</b>	<b>16,706</b>
<b>Natural Gas</b> (MMcf per day)	495	251
<b>Total Production</b> (BOE/per day)	<b>115,301</b>	<b>58,516</b>
Natural Gas Production (percentage of total)	71%	71%
Liquids Production (percentage of total)	29%	29%

Total production from the date of Acquisition to September 30, 2017 was 116,605 BOE per day, equivalent to 58,516 BOE per day for the nine months ended September 30, 2017.

#### Royalties

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

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

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

For the three and nine months ended September 30, 2017, the effective liquids royalty rate was 11.4 percent. In the third quarter and on a year-to-date basis in 2017, the effective natural gas royalty rate was 3.5 percent and 3.7 percent, respectively.

#### Expenses

##### Transportation

For the three and nine months ended September 30, 2017, transportation costs were \$1.96 per BOE. Transportation expenses include charges for the transportation of crude oil, natural gas and NGLs to the sales point.

##### Operating

Primary drivers of our operating expenses for the third quarter and on a year-to-date basis related to repairs and maintenance, workforce costs, processing fee expense, and property tax and lease costs. In the third quarter and on a year-to-date basis, operating costs were \$9.00 per BOE and \$8.95 per BOE, respectively.

#### Netbacks

(\$/BOE)	Three Months Ended September 30, 2017	May 17 - September 30, 2017
Sales Price	17.61	19.07
Royalties	1.28	1.34
Transportation and Blending	1.96	1.96
Operating Expenses	9.00	8.95
Production and Mineral Taxes	0.03	0.03
<b>Netback</b>	<b>5.34</b>	<b>6.79</b>

## Deep Basin – Capital Investment

In the Deep Basin, we are taking a disciplined approach to development activities. In 2017, capital investment is focused on the drilling and completion of horizontal production wells targeting liquids rich gas within the Deep Basin corridor.

(\$ millions)	May 17 – September 30, 2017
Drilling and Completions	47
Facilities	11
Other	19
<b>Capital Investment <sup>(1)</sup></b>	<b>77</b>

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

## Drilling Activity

(net wells, unless otherwise stated)	May 17 – September 30, 2017
Drilled	10
Completed	4
Tied-in	3

## Future Capital Investment

Our 2017 Deep Basin capital investment is forecast to be between \$160 million and \$180 million.

We are taking a disciplined development approach on the Deep Basin Assets through 2017 and anticipate ramping up our activity levels through 2020. We plan to focus capital investment on a number of drilling opportunities that have the potential to generate strong returns and start to use facilities that are currently underutilized.

## 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. Deep Basin DD&A for the three and nine months ended September 30, 2017 was \$91 million and \$136 million, respectively.

## CONVENTIONAL (DISCONTINUED OPERATIONS)

Our divestiture plans for our legacy Conventional assets are well underway. On September 29, 2017, we closed the sale of our Pelican Lake assets, including the adjacent Grand Rapids project, for gross cash proceeds of \$975 million. On September 25, 2017, we announced the sale of our Suffield crude oil and natural gas assets in southern Alberta for gross cash proceeds of \$512 million, plus a DPPA. As at September 30, 2017, the fair value of the DPPA was estimated to be between \$5 million and \$10 million. On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$1.3 billion. Both sales are expected to close in the fourth quarter, subject to customary closing conditions. The sales process for our CO<sub>2</sub> enhanced oil recovery project at Weyburn is progressing as planned and we expect to make a further divestiture announcement in the fourth quarter. The established assets in this segment have long life reserves, stable operations and produce a diversity of crude oil.

Significant developments that impacted our Conventional segment in the third quarter of 2017 compared with 2016 include:

- Recording a loss of \$603 million on the sale of our Pelican Lake assets and the adjacent Grand Rapids project;
- Our average liquids sales price increasing 13 percent to \$49.79 per barrel;
- Liquids and natural gas Netbacks, excluding realized risk management activities, of \$20.37 per barrel (2016 – \$20.63 per barrel) and \$0.53 per Mcf (2016 – \$1.25 per Mcf), respectively;
- Liquids production averaging 53,697 barrels per day, declining slightly from 2016 primarily due to expected natural declines, partially offset by an increase in production associated with the tight oil drilling program in southern Alberta; and
- Generating Operating Margin net of capital investment of \$75 million, a decrease of 32 percent.



The third quarter Conventional results include our Suffield and Pelican Lake assets.

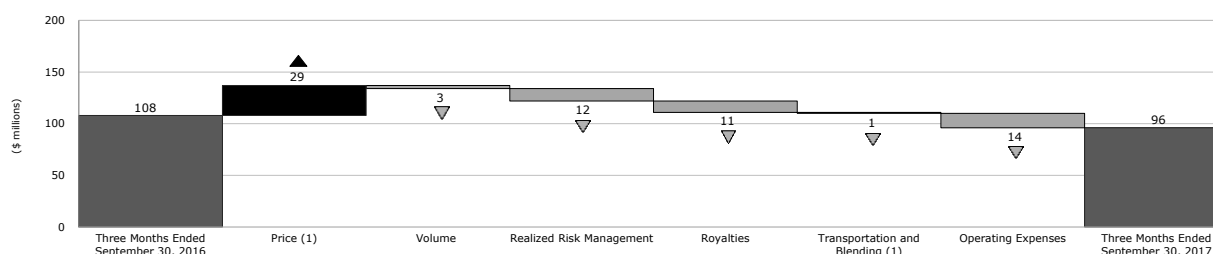
## Conventional – Liquids

### Three Months Ended September 30, 2017 Compared With September 30, 2016

#### Financial Results

(\$ millions)	Three Months Ended September 30,	
	2017	2016
<b>Gross Sales</b>	<b>268</b>	242
Less: Royalties	<b>43</b>	32
<b>Revenues</b>	<b>225</b>	210
<b>Expenses</b>		
Transportation and Blending	<b>41</b>	40
Operating	<b>79</b>	65
Production and Mineral Taxes	<b>4</b>	4
(Gain) Loss on Risk Management	<b>5</b>	(7)
<b>Operating Margin</b>	<b>96</b>	108
Capital Investment	<b>41</b>	39
<b>Operating Margin Net of Related Capital Investment</b>	<b>55</b>	69

#### 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

Our Conventional assets produce a variety of crude oils, ranging from heavy oil, which realizes a price based on the WCS benchmark, to light oil, which realizes a price closer to the WTI benchmark.

Our liquids sales price averaged \$49.79 per barrel in the third quarter of 2017, a 13 percent increase from 2016, due to higher crude oil benchmark prices, adjusted for applicable differentials, and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. As the cost of condensate decreases relative to the price of blended crude oil, our heavy oil sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our heavy oil sales price as we are using condensate purchased at a lower price earlier in the year.

##### Production Volumes

(barrels per day)	Three Months Ended September 30,		
	2017	Percent Change	2016
Heavy Oil	<b>25,549</b>	<b>(9)%</b>	28,096
Light and Medium Oil	<b>26,947</b>	<b>6%</b>	25,311
NGLs	<b>1,201</b>	<b>12%</b>	1,074
	<b>53,697</b>	<b>(1)%</b>	54,481

Total production declined slightly in 2017 compared with 2016 primarily as a result of expected natural declines, partially offset by an increase in light and medium oil associated with our tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

### Condensate

The heavy oil currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our blending ratios for Conventional heavy oil range between 10 percent and 16 percent. Revenues represent the total value of blended crude oil sold and includes the value of condensate. Consistent with the narrowing of the WCS-Condensate differential in the third quarter of 2017, the proportion of the cost of condensate recovered increased.

### Royalties

Conventional liquids royalties increased primarily due to higher royalty rates and an increase in our sales prices, partially offset by a decline in sales volumes. In the third quarter of 2017, the effective liquids royalty rate for our Conventional properties was 19.0 percent (2016 – 15.8 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The Pelican Lake crown royalty calculation was based on net profits in 2017 and 2016.

### Expenses

#### Transportation and Blending

Transportation and blending costs increased slightly in the third quarter of 2017. Transportation charges were higher due to increased costs associated with optimizing our sales, partially offset by a decline in sales volumes. Blending costs were relatively consistent as higher condensate prices were mostly offset by a decrease in condensate volumes.

#### Operating

Primary drivers of our operating expenses in the third quarter of 2017 were workover activities, workforce costs, electricity, property taxes and lease costs, and repairs and maintenance. Operating costs increased 24 percent to \$16.02 per barrel primarily due to:

- A rise in workover costs, repairs and maintenance, and fluid, waste handling and trucking costs as a result of increased activity; and
- An increase in electricity costs.

In the third quarter of 2017, production and mineral taxes were consistent with 2016.

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

(\$/bbl)	Heavy Oil		Light and Medium Oil	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2017	2016	2017	2016
Sales Price	48.01	40.50	51.91	48.97
Royalties	7.04	3.97	10.22	8.91
Transportation and Blending	5.45	4.86	2.85	2.71
Operating Expenses	15.50	12.43	17.19	13.94
Production and Mineral Taxes	0.01	0.01	1.54	1.48
<b>Netback Excluding Realized Risk Management</b>	<b>20.01</b>	19.23	<b>20.11</b>	21.93
Realized Risk Management Gain (Loss)	<b>(0.89)</b>	1.50	<b>(1.17)</b>	1.47
<b>Netback Including Realized Risk Management</b>	<b>19.12</b>	20.73	<b>18.94</b>	23.40

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

### Risk Management

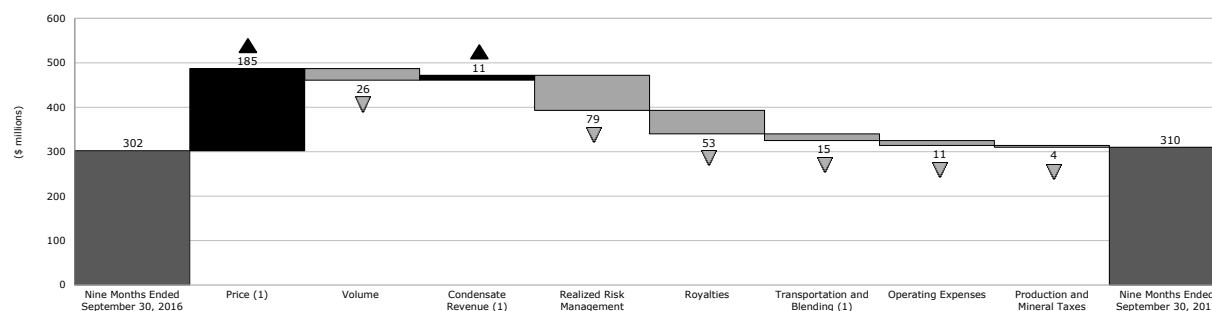
Risk management activities for the third quarter of 2017 resulted in realized losses of \$5 million (2016 – realized gains of \$7 million), consistent with average benchmark prices exceeding our contract prices.

## Nine Months Ended September 30, 2017 Compared With September 30, 2016

### Financial Results

(\$ millions)	Nine Months Ended September 30, 2017	2016
<b>Gross Sales</b>	<b>840</b>	670
Less: Royalties	<b>133</b>	80
<b>Revenues</b>	<b>707</b>	590
<b>Expenses</b>		
Transportation and Blending	<b>139</b>	124
Operating	<b>224</b>	213
Production and Mineral Taxes	<b>13</b>	9
(Gain) Loss on Risk Management	<b>21</b>	(58)
<b>Operating Margin</b>	<b>310</b>	302
Capital Investment	<b>173</b>	108
<b>Operating Margin Net of Related Capital Investment</b>	<b>137</b>	194

### 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

Our average liquids sales price increased 33 percent to \$51.03 per barrel consistent with the improvement in crude oil benchmark prices, net of applicable differentials.

#### Production Volumes

(barrels per day)	Nine Months Ended September 30,		
	2017	Percent Change	2016
Heavy Oil	<b>26,466</b>	<b>(10)%</b>	29,276
Light and Medium Oil	<b>26,430</b>	<b>1%</b>	26,200
NGLs	<b>1,128</b>	<b>10%</b>	1,027
	<b>54,024</b>	<b>(4)%</b>	56,503

Total production decreased primarily as a result of expected natural declines, partially offset by an increase in production associated with our tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

#### Royalties

Royalties increased \$53 million primarily due to an increase in our sales prices, higher royalty rates, and lower allowable costs for royalty purposes at Weyburn and Pelican Lake, partially offset by a reduction in sales volumes. For the nine months ended September 30, 2017, the effective liquids royalty rate for our Conventional properties was 19.2 percent (2016 – 14.9 percent).

## Expenses

### Transportation and Blending

Transportation and blending costs increased \$15 million, primarily due to a rise in blending costs as a result of higher condensate prices, partially offset by a decrease in condensate volumes, consistent with lower production. Transportation charges were lower largely due to a decline in sales volumes.

### Operating

Primary drivers of our operating expenses on a year-to-date basis in 2017 were workforce costs, workover activities, electricity, property taxes and lease costs and repairs and maintenance. Operating expenses increased \$1.26 per barrel, to \$15.17 per barrel.

The per unit increase was primarily due to lower production volumes, an increase in workover and repairs and maintenance activities, and higher energy costs. This increase was partially offset by a decrease in chemical costs associated with reduced polymer consumption.

Production and mineral taxes increased on a year-to-date basis due to the rise in crude oil prices.

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

(\$/bbl)	Heavy Oil		Light and Medium Oil	
	Nine Months Ended September 30,			
	2017	2016	2017	2016
Sales Price	47.46	34.18	54.97	43.66
Royalties	6.72	3.06	11.47	7.50
Transportation and Blending	4.44	4.50	2.79	2.74
Operating Expenses	14.30	12.94	16.68	15.52
Production and Mineral Taxes	0.01	-	1.77	1.15
<b>Netback Excluding Realized Risk Management</b>	<b>21.99</b>	13.68	<b>22.26</b>	16.75
Realized Risk Management Gain (Loss)	(1.47)	3.98	(1.46)	3.88
<b>Netback Including Realized Risk Management</b>	<b>20.52</b>	17.66	<b>20.80</b>	20.63

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

### Risk Management

Risk management activities for the nine months ended September 30, 2016 resulted in realized losses of \$21 million (2016 – realized gains of \$58 million), consistent with average benchmark prices exceeding our contract prices.

## Conventional – Natural Gas

### Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Gross Sales</b>	<b>62</b>	86	<b>247</b>	221
Less: Royalties	2	3	12	8
<b>Revenues</b>	<b>60</b>	83	<b>235</b>	213
<b>Expenses</b>				
Transportation and Blending	3	4	10	12
Operating	39	35	117	113
Production and Mineral Taxes	-	-	1	-
(Gain) Loss on Risk Management	(2)	-	(2)	1
<b>Operating Margin</b>	<b>20</b>	44	<b>109</b>	87
Capital Investment	1	2	7	6
<b>Operating Margin Net of Related Capital Investment</b>	<b>19</b>	42	<b>102</b>	81

The Operating Margin from natural gas continued to help fund growth opportunities in our Oil Sands and Deep Basin segments.

### Three and Nine Months Ended September 30, 2017 Compared With September 30, 2016

#### Revenues

##### Price

In the three months ended September 30, 2017, our average natural gas sales price decreased 22 percent to \$1.94 per Mcf, consistent with the decline in the AECO benchmark price. On a year-to-date basis, our average natural gas sales price increased 22 percent to \$2.58 per Mcf, consistent with the rise in the AECO benchmark price.

##### Production

Production decreased six percent to 350 MMcf per day in the third quarter of 2017. On a year-to-date basis, production declined eight percent to 351 MMcf per day due to expected natural declines.

##### Royalties

Royalties decreased slightly in the third quarter due to lower sales prices and production declines. On a year-to-date basis, royalties increased as a result of higher sales prices, partially offset by production declines. The average royalty rate in the third quarter and on a year-to-date basis was 5.1 percent (2016 – 4.5 percent and 4.4 percent, respectively).

#### Expenses

##### Transportation

In the three and nine months ended September 30, 2017, transportation costs declined slightly compared with 2016 primarily due to a decrease in sales volumes.

##### Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2017 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses increased in the three and nine months ended September 30, 2017 primarily due to an increase in repairs and maintenance.

##### Risk Management

Risk management activities resulted in realized gains of \$2 million in the third quarter and on a year-to-date basis (2016 – \$nil in the third quarter and realized losses of \$1 million on a year-to-date basis), consistent with our contract prices exceeding average benchmark prices.

#### Conventional – Capital Investment

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Heavy Oil	14	11	30	34
Light and Medium Oil	27	28	143	74
Natural Gas	1	2	7	6
<b>Capital Investment</b> <sup>(1)</sup>	<b>42</b>	<b>41</b>	<b>180</b>	<b>114</b>

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

Capital investment for the three and nine months ended September 30, 2017 was primarily related to sustaining capital and the purchase of CO<sub>2</sub> at Weyburn. On a year-to-date basis, capital investment also focused on our tight oil drilling opportunities in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets. Capital investment increased compared with 2016 as a result of limited crude oil capital investment activities in 2016 in response to the low commodity price environment.

#### Drilling Activity

(net wells, unless otherwise stated)	Nine Months Ended September 30,	
	2017	2016
Crude Oil	24	1
Recompletions	-	84
Gross Stratigraphic Test Wells	26	27

Drilling activity on a year-to-date basis in 2017 focused on drilling stratigraphic test wells and horizontal production wells for tight oil in southern Alberta.

## Future Capital Investment

We updated our 2017 guidance estimates to reflect our recently completed and anticipated divestiture activities. Our revised full-year 2017 Conventional capital investment guidance is forecast to be between \$210 million and \$225 million, mainly related to sustaining capital, a decrease of approximately 13 percent from July 26, 2017.

## DD&A and Exploration Expense

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.

No DD&A was recorded in the third quarter of 2017 due to the classification of the Conventional segment as held for sale as required by IFRS. DD&A in 2016 included impairment losses of \$210 million and \$65 million associated with our Northern Alberta cash-generating unit ("CGU") and Suffield CGU, respectively.

DD&A decreased \$687 million on a year-to-date basis primarily due to impairment losses of \$445 million recorded in 2016, the decision to divest our conventional assets, and a decline in sales volumes.

## REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. and operated by our partner, Phillips 66. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In the three and nine months ended September 30, 2017, we loaded an average of 10,542 and 11,166 gross barrels per day, respectively (2016 – 15,186 and 12,487 gross barrels per day, respectively).

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Crude Oil Capacity</b> (Mbbls/d)	<b>460</b>	460	<b>460</b>	460
<b>Crude Oil Runs</b> (Mbbls/d)	<b>462</b>	463	<b>439</b>	452
Heavy Crude Oil	<b>213</b>	241	<b>205</b>	237
Light/Medium	<b>249</b>	222	<b>234</b>	215
<b>Refined Products</b> (Mbbls/d)	<b>490</b>	494	<b>467</b>	479
Gasoline	<b>239</b>	235	<b>230</b>	235
Distillate	<b>156</b>	152	<b>147</b>	148
Other	<b>95</b>	107	<b>90</b>	96
<b>Crude Utilization</b> (percent)	<b>100</b>	101	<b>95</b>	98

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

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

In the third quarter, refined product output declined compared with 2016 primarily due to unplanned maintenance at both Refineries in 2017. Lower heavy crude oil volumes were processed due to optimization of the total crude input slate as a result of narrowing heavy crude oil differentials.

On a year-to-date basis, crude oil runs and refined product output decreased compared with 2016 primarily due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2017 compared with 2016, in addition to unplanned maintenance at both Refineries in 2017. Lower heavy crude oil volumes were processed due to the planned turnarounds in the first quarter of 2017 and optimization of the total crude input slate.

## Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues	2,161	2,245	7,162	5,962
Purchased Product	1,782	2,004	6,295	5,144
<b>Gross Margin</b>	<b>379</b>	241	<b>867</b>	818
<b>Expenses</b>				
Operating	168	172	579	557
(Gain) Loss on Risk Management	-	1	4	23
<b>Operating Margin</b>	<b>211</b>	68	<b>284</b>	238
Capital Investment	38	51	124	156
<b>Operating Margin Net of Related Capital Investment</b>	<b>173</b>	17	<b>160</b>	82

### 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, 2017, our gross margin increased primarily due to higher average market crack spreads and a rise in margins on the sale of our secondary products, such as NGLs, coke, and asphalt, due to higher realized prices. These increases in gross margin were partially offset by:

- Narrowing heavy crude oil differentials; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately \$15 million on our gross margin.

In the nine months ended September 30, 2017, our gross margin rose primarily due to higher average market crack spreads, and a rise in margins on the sale of our secondary products. These increases in gross margin were partially offset by:

- Narrowing heavy crude oil differentials;
- Lower crude utilization rates; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately \$9 million on our gross margin.

In the three and nine months ended September 30, 2017, the costs associated with Renewable Identification Numbers ("RINs") were \$81 million and \$208 million, respectively (2016 – \$80 million and \$209 million, respectively). The costs of RINs remained relatively consistent as the decrease in RINs benchmark prices was offset by an increase in the required RINs volume obligation.

### Operating Expense

Primary drivers of operating expenses in the third quarter and on a year-to-date basis of 2017 were labour, maintenance, utilities and supplies. Reported operating expenses were lower in the third quarter compared with 2016 primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by an increase in labour costs. On a year-to-date basis, operating expenses increased due to higher utility costs resulting from higher natural gas prices, and an increase in maintenance costs associated with the plant turnarounds in the first quarter of 2017.

### Refining and Marketing – Capital Investment

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Wood River Refinery	24	33	80	108
Borger Refinery	11	16	40	42
Marketing	3	2	4	6
	<b>38</b>	51	<b>124</b>	156

Capital expenditures in 2017 focused on capital maintenance and reliability work. Capital investment declined in the third quarter and on a year-to-date basis compared with 2016 primarily due to the completion of work on the debottlenecking project at the Wood River refinery in the third quarter of 2016.

We updated our 2017 guidance estimates upon further review of our capital program. Our revised full-year 2017 Refining and Marketing capital investment is forecast to be between \$180 million and \$200 million, mainly related to capital maintenance and reliability work. Guidance has decreased from July 26, 2017 by approximately five percent to reflect our continued focus on capital discipline.

## DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by \$1 million in the third quarter and \$5 million on a year-to-date basis, primarily due to the change in the U.S./Canadian dollar exchange rate.

## CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains on interest rate swaps and foreign exchange contracts. In the third quarter of 2017, our risk management activities resulted in \$486 million of unrealized losses (2016 – \$7 million of unrealized losses). On a year-to-date basis, we incurred \$75 million of unrealized risk management losses (2016 – \$440 million of unrealized losses). As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. On a year-to-date basis, we realized a \$142 million risk management gain on foreign exchange contracts primarily due to hedging activity undertaken to support the Acquisition.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, finance costs, interest income, foreign exchange (gain) loss, revaluation (gain), transaction costs, re-measurement of the contingent payment, research costs, (gain) loss on divestiture of assets, and other (income) loss.

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
General and Administrative	116	71	217	225
Finance Costs	191	97	458	292
Interest Income	(32)	(27)	(59)	(45)
Foreign Exchange (Gain) Loss, Net	(350)	45	(836)	(338)
Revaluation (Gain)	-	-	(2,524)	-
Transaction Costs	1	-	56	-
Re-measurement of the Contingent Payment	(43)	-	(109)	-
Research Costs	6	5	15	30
(Gain) Loss on Divestiture of Assets	(1)	5	-	6
Other (Income) Loss, Net	(2)	5	(4)	7
	<b>(114)</b>	201	<b>(2,786)</b>	177

## Expenses

### General and Administrative

Primary drivers of our general and administrative expenses in the third quarter of 2017 were workforce costs, long-term incentives and office rent. General and administrative expenses increased by \$45 million in the third quarter of 2017 compared with 2016 primarily due to \$18 million of costs related to the transitional services provided by ConocoPhillips, a \$12 million increase in long-term employee incentives costs related to an increase in our share price, and a \$10 million increase in workforce costs primarily due to the Acquisition.

On a year-to-date basis, primary drivers of our general and administrative expenses were workforce costs and office rent. In 2017, general and administrative expenses decreased by \$8 million compared with 2016 due to:

- Lower long-term employee incentive costs related to a drop in our share price;
- A non-cash expense of \$7 million for certain Calgary office space in excess of Cenovus's current and near-term requirements, compared with \$31 million in 2016; and
- Lower information technology costs due to process improvements.

These decreases were partially offset by approximately \$28 million of transitional services provided by ConocoPhillips. Under the purchase and sales agreement, Cenovus and ConocoPhillips agreed to certain transitional services where ConocoPhillips will provide certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions are in the normal course of operations and are measured at the exchange amounts.

### Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. In the third quarter and on a year-to-date basis, finance costs increased by \$94 million and \$166 million, respectively, primarily due to costs associated with additional debt incurred to finance the Acquisition, including US\$2.9 billion of senior unsecured notes, \$3.6 billion borrowed under a committed Bridge Facility and borrowings through our existing committed credit facility. The first tranche and a



portion of the second tranche of the committed Bridge Facility were repaid on September 29, 2017 with proceeds from the sale of our Pelican Lake assets and the adjacent Grand Rapids project. As at September 30, 2017, \$2.65 billion remains outstanding on the committed Bridge Facility. As at September 30, 2017, no amounts were drawn on the existing committed credit facility.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2017 was 4.7 percent and 4.9 percent, respectively (2016 – 5.3 percent).

### Foreign Exchange

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Unrealized Foreign Exchange (Gain) Loss	(440)	50	(908)	(341)
Realized Foreign Exchange (Gain) Loss	90	(5)	72	3
	(350)	45	(836)	(338)

In the third quarter and on a year-to-date basis in 2017, unrealized foreign exchange gains resulted primarily from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar at September 30, 2017, strengthened by four percent and eight percent respectively, in comparison to June 30, 2017 and December 31, 2016. On a year-to-date basis, unrealized foreign exchange gains also resulted from the translation of U.S. cash that was accumulated leading up to the Acquisition.

In the third quarter and on a year-to-date basis in 2017, realized foreign exchange losses primarily resulted from an increase in the number of sales contracts denominated in U.S. dollars.

### Revaluation Gain

Prior to the Acquisition, our 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, “*Joint Arrangements*” and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, we control FCCL, as defined under IFRS 10, “*Consolidated Financial Statements*” and accordingly, FCCL has been consolidated. As required by IFRS 3 when control is achieved in stages, the previously held interest in FCCL was re-measured to its fair value of \$12.3 billion and a non-cash revaluation gain of \$2.5 billion (\$1.8 billion, after-tax) was recorded in net earnings in the second quarter of 2017.

### Transaction Costs

On a year-to-date basis in 2017, we expensed \$56 million of transaction costs related to the Acquisition.

### Re-measurement of Contingent Payment

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

The contingent payment is accounted for as a financial option. The fair value of \$361 million on May 17, 2017 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is subsequently re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. At September 30, 2017, the contingent payment was valued at \$252 million. In the three and nine months ended September 30, 2017, there was a re-measurement gain of \$43 million and \$109 million, respectively. WCS in the third quarter of 2017 averaged less than \$52 per barrel, therefore no amount was payable.

Average WCS forward pricing for the remaining term of the contingent payment is US\$35.51 or C\$44.28 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C\$42.50 per barrel and C\$48.60 per barrel.

### DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in the third quarter was \$15 million (2016 – \$14 million) and \$47 million on a year-to-date basis (2016 – \$50 million).

## Income Tax

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Current Tax				
Canada	(23)	(71)	(232)	(187)
United States	(39)	-	(40)	1
<b>Total Current Tax Expense (Recovery)</b>	<b>(62)</b>	<b>(71)</b>	<b>(272)</b>	<b>(186)</b>
<b>Deferred Tax Expense (Recovery)</b>	<b>(48)</b>	<b>5</b>	<b>893</b>	<b>(91)</b>
<b>Tax Expense (Recovery) From Continuing Operations</b>	<b>(110)</b>	<b>(66)</b>	<b>621</b>	<b>(277)</b>

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

(\$ millions)	Nine Months Ended September 30,	
	2017	2016
<b>Earnings (Loss) From Continuing Operations Before Income Tax</b>	<b>3,701</b>	<b>(527)</b>
Canadian Statutory Rate	<b>27.0%</b>	<b>27.0%</b>
<b>Expected Income Tax (Recovery)</b>	<b>999</b>	<b>(142)</b>
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	<b>(31)</b>	<b>(38)</b>
Non-Taxable Capital (Gains) Losses	<b>(148)</b>	<b>(46)</b>
Non-Recognition of Capital (Gains) Losses	<b>(121)</b>	<b>(46)</b>
Adjustments Arising From Prior Year Tax Filings	<b>(36)</b>	<b>(48)</b>
Recognition of Previously Unrecognized Capital Losses	<b>(65)</b>	<b>-</b>
Non-Deductible Expenses	<b>3</b>	<b>6</b>
Other	<b>20</b>	<b>37</b>
<b>Total Expense (Recovery) From Continuing Operations</b>	<b>621</b>	<b>(277)</b>
<b>Effective Tax Rate</b>	<b>16.8%</b>	<b>52.6%</b>

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

In the three and nine months ended September 30, 2017, a current tax recovery was recorded on continuing operations due to the carry back of current and prior year losses and an adjustment related to prior years. In the third quarter, we recorded a deferred tax recovery as compared to an expense in 2016 on continuing operations. On a year-to-date basis, a deferred tax expense was recorded in 2017 compared with a recovery in 2016 on continuing operations due to the revaluation gain of our pre-existing interest in connection with the Acquisition.

In the three and nine months ended September 30, 2017, we recorded an income tax expense of \$31 million and \$51 million, respectively, related to discontinued operations (2016 - \$89 million and \$176 million income tax recovery, respectively). The loss on discontinuance includes a \$163 million deferred tax recovery.

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 higher U.S. tax rates, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences. Our effective tax rate differs from the statutory tax rate due to \$715 million of unrealized non-taxable foreign exchange gains.

## LIQUIDITY AND CAPITAL RESOURCES

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
<b>Cash From (Used In)</b>				
Operating Activities	592	310	2,159	697
Investing Activities	512	(196)	(14,653)	(835)
<b>Net Cash Provided (Used) Before Financing Activities</b>	<b>1,104</b>	114	<b>(12,494)</b>	(138)
Financing Activities	(1,009)	(41)	9,227	(125)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	48	(3)	179	8
<b>Increase (Decrease) in Cash and Cash Equivalents</b>	<b>143</b>	70	<b>(3,088)</b>	(255)
			<b>September 30,</b>	December 31,
			<b>2017</b>	2016
<b>Cash and Cash Equivalents</b>			<b>632</b>	3,720
<b>Committed and Undrawn Credit Facilities</b>			<b>4,500</b>	4,000

### Cash From (Used In) Operating Activities

Cash from operating activities increased for the three and nine months ended September 30, 2017 mainly due to higher Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, assets and liabilities held for sale and the current portion of the contingent payment we had working capital of \$1,302 million at September 30, 2017 compared with \$4,423 million at December 31, 2016. The decrease in working capital was primarily due to the Acquisition.

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 2017, cash from investing activities was primarily due to cash proceeds from the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project, partially offset by an increase in capital investment. In 2016, capital investment was limited due to spending reductions in response to the low commodity price environment.

On a year-to-date basis, the increase in cash used in investing activities was primarily due to the Acquisition and a rise in capital investment, partially offset by proceeds on the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project. In 2016, capital investment was limited due to spending reductions in response to the low commodity price environment.

### Cash From (Used In) Financing Activities

Cash used in financing activities increased in the third quarter of 2017 primarily related to the repayment of the first tranche and a portion of the second tranche of the committed Bridge Facility. On a year-to-date basis, the increase in cash from financing activities was primarily due to the issuance of debt and common shares to help finance the Acquisition, partially offset by the repayment of a portion of the committed Bridge Facility.

Total debt as at September 30, 2017 was \$12,094 million (December 31, 2016 – \$6,332 million), which includes \$9,547 million of U.S. denominated senior unsecured notes with no principal payments due until October 15, 2019 (US\$1.3 billion) and \$2.65 billion under a committed Bridge Facility, both amounts are partially offset by debt discount and transaction costs. The \$5,762 million increase in total debt is primarily due to Acquisition financing.

As at September 30, 2017, we were in compliance with all of the terms of our debt agreements.

### Senior Unsecured Notes

In connection with the Acquisition, on April 7, 2017, we completed an offering in the U.S. for US\$2.9 billion of senior unsecured notes issued in three tranches, US\$1.2 billion 4.25 percent senior unsecured notes due April 2027, US\$700 million 5.25 percent senior unsecured notes due June 2037, and US\$1.0 billion 5.40 percent senior unsecured notes due June 2047 (collectively, the "2017 Notes"). In connection with the offering of the 2017 Notes, we agreed to make an exchange offer (the "Exchange Offering") for the 2017 Notes whereby the holders will be entitled to exchange the 2017 Notes for new notes with the same terms and provisions, except that the new notes will not be subject to transfer restrictions.

### **Base Shelf Prospectus**

On October 10, 2017, we filed a base shelf prospectus that allows us to offer, from time to time, up to US\$7.5 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. The base shelf prospectus also allows us to conduct the Exchange Offering and ConocoPhillips to offer, 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 November 2019 and replaces our US\$5.0 billion base shelf prospectus, which would have expired in March 2018. Offerings under the base shelf prospectus are subject to market conditions.

### **Committed Bridge Facility**

On May 17, 2017, concurrent with the close of the Acquisition, we borrowed \$3.6 billion under a committed Bridge Facility. The Bridge Facility consisted of a \$0.9 billion tranche maturing on May 17, 2018, a \$1.8 billion tranche maturing on November 17, 2018, and a \$0.9 billion tranche maturing on May 17, 2019. On September 29, 2017, the first tranche and a portion of the second tranche were repaid resulting in \$2.65 billion outstanding as at September 30, 2017. We expect to repay the remainder of the committed Bridge Facility with proceeds from the announced divestitures and further planned divestitures.

### **Common Shares**

In connection with the Acquisition, on April 6, 2017, Cenovus closed a Bought-Deal Common Share Offering for 187.5 million common shares for gross proceeds of \$3.0 billion.

### **Dividends**

In the three and nine months ended September 30, 2017, we paid dividends of \$0.05 per share or \$62 million and \$0.15 per share or \$164 million, respectively (2016 – \$0.05 per share or \$41 million and \$0.15 per share or \$124 million, respectively). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

### **Available Sources of Liquidity**

We expect cash flows from our liquids, natural gas and refining operations to fund a portion of our cash requirements. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, DBRS Limited, and Fitch Ratings.

The following sources of liquidity are available at September 30, 2017:

(\$ millions)	Term	Amount
Cash and Cash Equivalents	Not applicable	632
Committed Credit Facility – Tranche A	November 2021	3,300
Committed Credit Facility – Tranche B	November 2020	1,200

### **Committed Credit Facility**

On April 28, 2017, we amended our existing committed credit facility to increase the capacity of the facility by \$0.5 billion to \$4.5 billion and to extend the maturity dates. The committed credit facility consists of a \$1.2 billion tranche maturing on November 30, 2020 and \$3.3 billion tranche maturing on November 30, 2021. As of September 30, 2017, we had \$4.5 billion available under our committed credit facility.

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

See below for the Debt to Capitalization ratio used by Cenovus to monitor our capital structure.

### **Financial Metrics**

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

Over the long-term, we target a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

As at	<b>September 30, 2017</b>	December 31, 2016
Net Debt to Capitalization <sup>(1) (2)</sup>	<b>37%</b>	18%
Debt to Capitalization	<b>38%</b>	35%
Net Debt to Adjusted EBITDA <sup>(1)</sup>	<b>4.1x</b>	1.9x
Debt to Adjusted EBITDA	<b>4.3x</b>	4.5x

(1) Net Debt is defined as Debt net of cash and cash equivalents.

(2) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

Debt to Capitalization increased as a result of the higher long-term debt balance, related to the Acquisition, partially offset by the increase in Shareholders' Equity and the strengthening of the Canadian dollar relative to the U.S. dollar. Debt to Adjusted EBITDA decreased as a result of a higher Adjusted EBITDA from an increase in commodity prices and the rise in sales volumes as a result of the Acquisition, partially offset by a higher long-term debt balance. We are intently focused on completing divestitures of our legacy Conventional assets in order to deleverage our balance sheet.

As at September 30, 2017, Cenovus's Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA are 4.3x and 4.1x, respectively. These ratios are well outside our target range. However, it is important to note that Adjusted EBITDA is calculated on a rolling twelve month basis and as such, only includes the financial results from the Deep Basin Assets and the additional 50 percent of FCCL for the period May 17, 2017 to September 30, 2017. Debt and Net Debt are as at September 30, 2017; therefore, the ratios are fully burdened by the debt issued to finance the Acquisition. If Adjusted EBITDA reflected a full twelve months of earnings from the acquired assets, Cenovus's Debt and Net Debt to Adjusted EBITDA ratios would be substantially lower.

Additional information regarding our financial measures and capital structure can be found in the notes to the December 31, 2016 Consolidated Financial Statements and the interim Consolidated Financial Statements.

### Share Capital and Stock-Based Compensation Plans

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as a Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Certain directors, officers or employees chose prior to December 31, 2016 to convert a portion of their remuneration, paid in the first quarter of 2017, into DSUs. The election for any particular year is irrevocable. DSUs may not be redeemed until departure. Directors also received an annual grant of DSUs.

Refer to Note 21 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at September 30, 2017	<b>Units Outstanding (thousands)</b>	<b>Units Exercisable (thousands)</b>
Common Shares	<b>1,228,790</b>	<b>N/A</b>
Stock Options	<b>42,864</b>	<b>36,326</b>
Other Stock-Based Compensation Plans	<b>15,537</b>	<b>1,633</b>

In connection with the Acquisition, Cenovus closed a Bought-Deal Common Share financing on April 6, 2017 for 187.5 million common shares, raising gross proceeds of \$3.0 billion (\$2.9 billion net of \$101 million of share issuance costs).

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

### Contractual Obligations and Commitments

Cenovus has obligations for goods and services that were entered into in the normal course of business. Obligations are primarily related to demand charges on firm transportation agreements, operating leases on buildings, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the December 31, 2016 Consolidated Financial Statements.

As at September 30, 2017, total commitments were \$20.7 billion, of which \$17.2 billion were for various transportation commitments. During the nine months ended September 30, 2017, our transportation commitments decreased by \$9.1 billion, primarily due to our withdrawal from certain transportation initiatives, including the cancellation of the Energy East Pipeline, and use of contracts, partially offset by new firm transportation agreements. In relation to the Acquisition, we assumed \$3.7 billion primarily consisting of transportation commitments on various pipelines. Transportation commitments include \$7.5 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2016 – \$19.2 billion). Terms are up to 20 years subsequent to the date of commencement and should help align our future transportation requirements with our anticipated production growth.

As at September 30, 2017, there were outstanding letters of credit aggregating \$257 million issued as security for performance under certain contracts (December 31, 2016 – \$258 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 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, 2017, the estimated fair value of the contingent payment was \$252 million. WCS in the third quarter of 2017 averaged less than \$52 per barrel; therefore, no amount was payable. 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. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

See the Corporate and Eliminations section of this MD&A for more details.

## **RISK MANAGEMENT**

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For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2016 annual MD&A and the first and second quarter 2017 MD&A. In addition, a description of the risk factors and uncertainties can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2016.

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. Actively managing these risks improves our ability to effectively execute our business strategy. We continue to be exposed to the risks identified in our 2016 annual MD&A, the first and second quarter 2017 MD&A and our AIF.

The following provides an update on our risks related to commodity prices, risks related to the Acquisition, and risks related to asset divestitures.

### **Commodity Price Risk**

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 23 and 24 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 minimized 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,			2016		
	2017	2017	2017	2016	2016	2016
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	9	483	492	(32)	(5)	(37)
Refining	-	2	2	1	-	1
Power	-	-	-	(3)	-	(3)
Interest Rate	-	1	1	-	12	12
Foreign Exchange	1	-	1	-	-	-
<b>(Gain) Loss on Risk Management <sup>(1)</sup></b>	<b>10</b>	<b>486</b>	<b>496</b>	<b>(34)</b>	<b>7</b>	<b>(27)</b>
Income Tax Expense (Recovery)	(18)	(132)	(150)	9	(2)	7
<b>(Gain) Loss on Risk Management, After Tax</b>	<b>(8)</b>	<b>354</b>	<b>346</b>	<b>(25)</b>	<b>5</b>	<b>(20)</b>

(1) Excludes \$3 million of realized risk management losses on contracts from our Conventional segment (2016 – \$7 million realized risk management gains), which has been classified as a discontinued operation.

(\$ millions)	Nine Months Ended September 30,			2016		
	2017	2017	2017	2016	2016	2016
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	72	66	138	(138)	359	221
Refining	4	(1)	3	(4)	4	-
Power	-	-	-	-	(14)	(14)
Interest Rate	-	10	10	-	91	91
Foreign Exchange	(142)	-	(142)	-	-	-
<b>(Gain) Loss on Risk Management <sup>(2)</sup></b>	<b>(66)</b>	<b>75</b>	<b>9</b>	<b>(142)</b>	<b>440</b>	<b>298</b>
Income Tax Expense (Recovery)	-	(20)	(20)	37	(120)	(83)
<b>(Gain) Loss on Risk Management, After Tax</b>	<b>(66)</b>	<b>55</b>	<b>(11)</b>	<b>(105)</b>	<b>320</b>	<b>215</b>

(2) Excludes \$19 million of realized risk management losses on contracts from our Conventional segment (2016 – \$57 million realized risk management gains), which has been classified as a discontinued operation.

In the third quarter of 2017 and on a year-to-date basis, we incurred realized losses on crude oil risk management activities, consistent with average benchmark prices exceeding our contract prices. On a year-to-date basis, we incurred realized gains on foreign exchange contracts undertaken to support the Acquisition. Unrealized losses were recorded on our crude oil financial instruments in the three and nine months ended September 30, 2017 primarily due to the realization of settled positions and changes in benchmark prices.

## Risks Related to the Acquisition and Asset Divestitures

### Unexpected Costs or Liabilities Related to the Acquisition

Acquisitions of crude oil and natural gas properties are based largely on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of crude oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of crude oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Although we conducted title and environmental reviews in respect of the Deep Basin Assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat our title to certain assets or that environmental defects or deficiencies do not exist.

In connection with the Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence conducted prior to the execution of the Acquisition Agreement and we may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities could have a material adverse effect on our business, financial condition or future prospects. In addition, the Acquisition Agreement limits the amount for which we are indemnified, such that liabilities in respect of the Acquisition may be greater than the amounts for which we are indemnified under the Acquisition Agreement.

### Realization of Acquisition Benefits

We believe that the Acquisition will provide a number of benefits to Cenovus. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, may cost more to achieve or may not occur within the time periods that we anticipate. The realization of such benefits may be affected by a number of factors, many of which are beyond our control.

### ***Amount of Contingent Payments***

In connection with the Acquisition, we have agreed to make contingent payments under certain circumstances. The amount of contingent payments will vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Acquisition, and such payments may be significant. In addition, in the event that such payments are made, this could have an adverse impact on our reported results and other metrics.

### ***Significant Transaction and Related Costs***

We expect to incur a number of costs associated with completing the Acquisition, integrating the Deep Basin Assets and completing the targeted asset sales. The majority of such costs will consist of acquisition, facilities and systems consolidation and employment-related costs. Additional unanticipated costs may be incurred in the integration of the assets to be acquired under the Acquisition (collectively, the "Acquired Assets") into our business and completing the targeted asset sales.

### ***Operational and Reserves and Resources Risks Relating to the Acquired Assets***

The risk factors set forth in our AIF relating to the crude oil and natural gas business, environmental matters and the operations and reserves and resources of Cenovus apply equally in respect of the Acquired Assets. In particular, the reserves, resources and recovery information contained in the reserves and resources reports in respect of the Acquired Assets is only an estimate and the actual production from and ultimate reserves of those properties may be greater or less than the estimates contained in such reports.

### ***Risk of Default in the Repayment of Borrowings under the Credit Facilities***

We have incurred material indebtedness under our committed Bridge Facility. We intend to repay borrowings under the committed Bridge Facility through the sale of certain of our assets. We may not be able to sell such assets in the time period we estimate, or for prices we expect to realize from such sales. If we are unable to sell such assets on the terms that we expect to receive, or at all, our ability to repay borrowings under the committed Bridge Facility as anticipated could be adversely affected. In the event we are unable to refinance borrowings we incur under our committed Bridge Facility in the manner intended, we may be required to utilize other sources of liquidity including cash on hand, cash from operating activities or borrowings under our existing committed credit facility to the extent of any availability thereunder. We may also be required to seek extensions to or modifications of the terms of our existing committed credit facility or committed Bridge Facility in order to defer the maturity dates of borrowings incurred thereunder. In recent years, depressed prices for crude oil and natural gas have materially affected the operating and financial performance of borrowers in the energy sector which has at times resulted in the curtailment of the availability of credit from lenders, and an unwillingness to provide borrowers with desired extensions to, or other modifications of, repayment terms. As a result, depending on crude oil and natural gas and credit market conditions at the time when borrowings under our existing committed credit facility or committed Bridge Facility are due for repayment, and our own financial performance at that time, we may be unable to obtain extensions or modifications of the terms of our existing committed credit facility or committed Bridge Facility on terms satisfactory to us, or at all, which could result in us defaulting on our repayment obligations under our existing committed credit facility or committed Bridge Facility and being subject to various remedies available to the lenders thereunder including remedies available under applicable bankruptcy and insolvency legislation.

### ***Increased Indebtedness***

In order to finance the Acquisition, we borrowed \$3.6 billion on a committed Bridge Facility and issued US\$2.9 billion in senior unsecured notes. Such borrowings represent a significant increase in Cenovus's consolidated indebtedness. Such additional indebtedness increased Cenovus's interest expense and debt service obligations and may have a negative effect on Cenovus's results of operations. On September 29, 2017, we completed the sale of our Pelican Lake assets and the adjacent Grand Rapids project, the first of a series of anticipated divestitures, for gross cash proceeds of \$975 million. Net cash proceeds from the sale were applied against the \$3.6 billion committed Bridge Facility. As at September 30, 2017, we had \$2.65 billion outstanding on the committed Bridge Facility. On September 25, 2017, we announced the sale of our Suffield assets for gross cash proceeds of \$512 million, plus a DPPA. In addition, on October 19, 2017, we announced the sale of our Palliser assets for gross cash proceeds of \$1.3 billion. Both transactions are expected to close in the fourth quarter of 2017, subject to customary closing conditions. Net proceeds from the divestitures will be applied against the committed Bridge Facility.

Cenovus's ability to service its increased debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions, interest rate fluctuations and financial, business, regulatory and other factors, some of which are beyond Cenovus's control. If Cenovus's operating results are not sufficient to service its current or future indebtedness, Cenovus may be forced to take actions such as reducing dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing its debt, or seeking additional equity capital.

Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. The increased indebtedness of Cenovus arising from the Acquisition could be a factor considered by the ratings agencies in downgrading Cenovus's credit rating. If a rating agency were to downgrade Cenovus's credit



rating, Cenovus's borrowing costs could increase and its funding sources could decrease. In addition, a failure by Cenovus to maintain its current credit ratings could affect its business relationships with suppliers and operating partners. A credit downgrade could also adversely affect the availability and cost of capital needed to fund the growth investments that are a central element to Cenovus's long-term business strategy.

#### ***Suffield and Palliser Divestitures***

We have announced the divestiture of our Suffield and Palliser assets, which are expected to close in the fourth quarter. Both divestitures are subject to required regulatory approvals and the satisfaction of certain closing conditions. There is no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. If they are not satisfied or waived, the divestitures will not be completed. In addition, a substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms or conditions in the approvals could have a material adverse effect on our ability to complete the divestitures and on our business, financial condition, results of operations or cash flows following the divestitures. If the divestitures are not completed as contemplated, we could suffer adverse consequences, including the loss of investor confidence.

#### ***British Columbia Exposure***

Pursuant to the Acquisition, we acquired approximately 0.9 million gross acres (0.7 million net acres) of land holdings in British Columbia, which exposes us to the following additional risks.

#### *Aboriginal Claims*

Aboriginal groups have claimed aboriginal title and rights to portions of Western Canada, including British Columbia, and such claims, if successful, could have a material negative impact on Cenovus. The Governments of Canada and British Columbia have a duty to consult with Aboriginal people in relation to actions and decisions which may impact those rights and claims and, in certain cases, have a duty to accommodate their concerns. These duties have the potential to adversely affect Cenovus's ability to obtain and renew permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. The scope of the duty to consult by the federal Government of Canada and the Government of British Columbia is subject to ongoing litigation which may result in uncertainty with respect to the process to obtain permits, leases, licenses and other approvals. Opposition by Aboriginal groups may also negatively impact Cenovus in terms of public perception, diversion of Management's time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in Cenovus's operations, or court-ordered relief impacting Cenovus's operations. Challenges by Aboriginal groups could adversely impact Cenovus's progress and ability to explore and develop its properties.

#### *Climate Change Regulation*

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80 percent reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia has committed to implementing a formal policy to regulate carbon capture and storage projects.

Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45 percent reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that will involve a new offset protocol and a Clean Infrastructure Royalty Credit Program, and finally a Future phase that will include the development and implementation of new methane emissions reduction standards.

#### *Environmental Regulation*

In British Columbia, the Oil and Gas Activities Act (the "OGAA") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The Environmental Protection and Management Regulation establishes the government's environmental objectives for Crown lands for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not exclusively an environmental statute, the Petroleum and Natural Gas Act, in conjunction with the OGAA, requires companies to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

### *Royalty Regime*

Producers of crude oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of crude oil and natural gas produced. The amount payable as a royalty in respect of crude oil depends on the type and vintage of the crude oil, the quantity of crude oil produced in a month and the value of that crude oil. Generally, crude oil is classified as either light or heavy and the vintage of crude oil is classified as either: "old oil" that is produced from a pool with a completed well that first recovered crude oil before October 31, 1975; "new oil" that is produced from a pool with a completed well that first recovered oil between October 31, 1975 and June 1, 1998; or "third-tier oil" that is produced from a pool with a completed well that first recovered crude oil after June 1, 1998 or through an enhanced oil recovery scheme. The royalty calculation takes into account the production of crude oil on a well-by-well basis, the specified royalty rate for a given vintage of crude oil, the average unit-selling price of the crude oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with crude oil), the royalty rate depends on the date of acquisition of the crude oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on NGLs are levied at a flat rate of 20 percent of sales volume.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, and is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25 percent. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to \$4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale between \$1.25 – \$4.94 per hectare, depending on the total number of hectares owned by the entity.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50 percent of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased crude oil and natural gas exploration and production in under-developed areas and to extend the drilling season.

Any future changes by the Government of British Columbia to the royalty programs or regimes could have a significant impact on Cenovus's financial condition, results of operations and future capital expenditures.

## **CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES**

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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 annual December 31, 2016 Consolidated Financial Statements and the interim Consolidated Financial Statements for the period ended September 30, 2017.

### **Critical Judgments in Applying Accounting Policies**

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies during the nine months ended September 30, 2017. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2016.

### **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. Further to those areas discussed in the annual Consolidated Financial Statements for the year ended December 31, 2016 and the annual MD&A, the estimation of fair values of the assets acquired and liabilities assumed in a business combination, including the contingent payment and goodwill, is a key area involving significant estimates or judgments.

### **Recent Accounting Pronouncements**

There were no new or amended accounting standards or interpretations adopted during the nine months ended September 30, 2017.

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

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning after January 1, 2017 and have not been applied in preparing the interim Consolidated Financial Statements. The following provides an update to the disclosure in the annual Consolidated Financial Statements for the year ended December 31, 2016.

#### **Revenue Recognition**

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The standard may be applied retrospectively or using the retrospective with cumulative effect approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plan to adopt the standard for the year ended December 31, 2018.

#### **Leases**

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively.

We plan to apply IFRS 16 on January 1, 2019. A transition team is assessing the impacts of adopting IFRS 16 and will oversee changes to accounting systems, processes and internal controls. The estimated time and effort necessary to develop and implement required changes (including the impact to information technology systems) extends into 2018. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Consolidated Balance Sheets.

## **CONTROL ENVIRONMENT**

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Except for changes relating to the continuing integration of the Deep Basin Assets, as discussed below, there have been no changes to internal control over financial reporting ("ICFR") or disclosure controls and procedures ("DC&P") during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, ICFR or DC&P.

As permitted by and in accordance with, National Instrument 52-109, "Certification of Disclosure in Issuers' Annual and Interim Filings", Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures of the Deep Basin Assets that were acquired on May 17, 2017 (see the Financing the Acquisition section of this MD&A for more details). Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to the Deep Basin Assets in a manner consistent with our other operations. Summary financial information related to the Deep Basin Assets included in the interim Consolidated Financial Statements is as follows:

(\$ millions)	<b>Three Months Ended September 30, 2017</b>
Revenues	<b>187</b>
Operating Margin <sup>(1)</sup>	<b>64</b>
Net Earnings (Loss)	<b>(27)</b>
<hr/>	
As at	<b>September 30, 2017</b>
Current Assets	<b>130</b>
Non-Current Assets <sup>(1)</sup>	<b>6,570</b>
Current Liabilities	<b>115</b>
Non-Current Liabilities <sup>(1)</sup>	<b>621</b>

<sup>(1)</sup> Summary financial information included within net earnings (loss), non-current assets, and non-current liabilities includes both information obtained from predecessor accounting systems prior to full conversion to Cenovus systems, as well as financial information that is included in our accounting systems, such as, property, plant and equipment, exploration and evaluation assets, decommissioning liabilities, and long-term incentive costs.

In addition, we acquired approximately \$500 million of Deep Basin commitments primarily consisting of transportation commitments on various pipelines.

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 2017 to be a transformational year for Cenovus. The close of the Acquisition in the second quarter of 2017 increased our interest in FCCL to 100 percent and provided us with a second core operating area in the Deep Basin. As part of our ongoing efforts to optimize our asset portfolio and focus on deleveraging our balance sheet, we announced our intention to sell our legacy Conventional crude oil and natural gas assets in the first half of 2017. In the third quarter, we successfully completed the sale of our Pelican Lake assets and the adjacent Grand Rapids project, and announced the sale of our Suffield assets. Furthermore, on October 19, 2017, we announced the divestiture of our Palliser assets. Both transactions are expected to close in the fourth quarter of 2017. The divestiture process for our remaining legacy Conventional assets, notably our CO<sub>2</sub> enhanced oil recovery project at Weyburn, in southern Saskatchewan, is proceeding well.

We believe we are well-positioned for continued market and commodity price volatility. We will continue to look for ways to increase our margins through strong operating performance and cost leadership, while delivering safe and reliable operations. Proactively managing our market access commitments and opportunities should assist with our goal of reaching a broader customer base to secure a higher sales price for our liquids production.

We have reduced the amount of capital needed to sustain our base business and expand our projects, which we expect will allow us to reactivate growth in a disciplined manner. We believe these efforts will help to ensure our financial resilience.

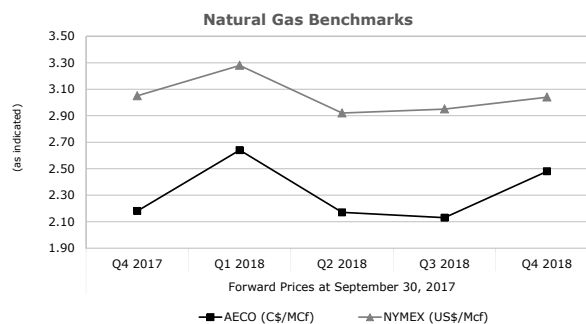
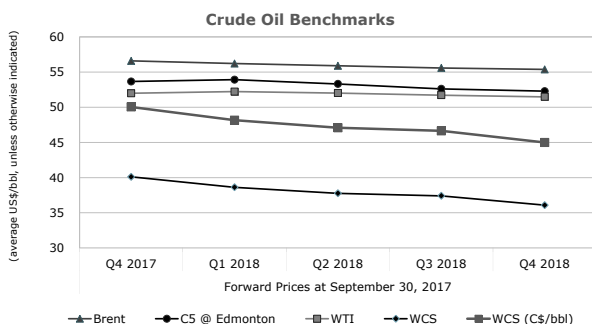
The following outlook commentary is focused on the next twelve to fifteen months.

### **Commodity Prices Underlying our Financial Results**

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility to continue and a modest price improvement in the next fifteen months. OPEC's ability to adhere to its current production cuts and the possibility of future production cuts, combined with annual increases in demand growth should support prices, constrained by the need to draw down surplus crude oil inventories and U.S. production growth;
- We anticipate the Brent-WTI differential will narrow after the impacts of severe weather related incidents dissipate and as a result of the U.S. exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and

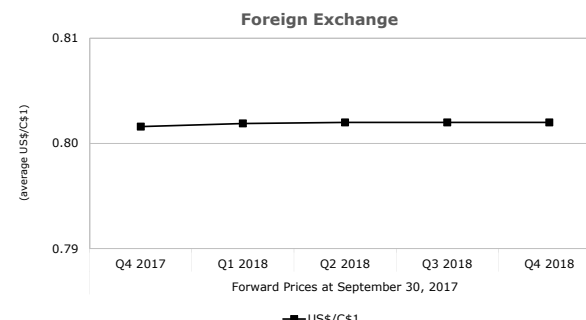
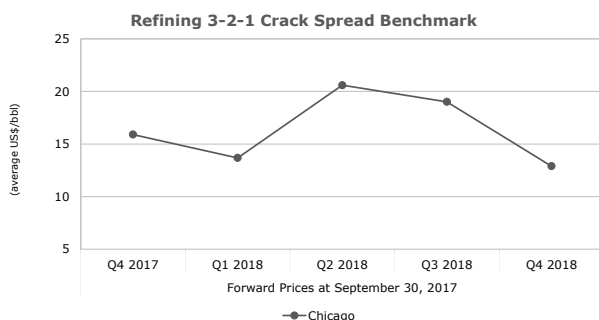
- We expect that the WTI-WCS differential will widen due to Canadian supply increasing due to the resolution of production outages, oil sands supply growth and potential transportation constraints, partially offset by the possibility of OPEC extending production cuts.



Natural gas prices are anticipated to improve in the fourth quarter of 2017 and first quarter of 2018 with a normal winter heating season and increased U.S. natural gas exports, partially offset by expected North American natural gas supply growth. In addition, recent pipeline and compressor station maintenance within Alberta will increase exports out of western Canada, helping to improve AECO prices.

U.S. refining crack spreads are expected to weaken in the fourth quarter of 2017 as refinery capacity returns after severe weather events and due to seasonal demand weakness. Seasonal demand changes will result in fluctuations of refining cracks spreads throughout the remainder of 2018. The impact of weaker refining crack spreads on refinery margins will be partially offset by the widening of the WTI-WCS differential, which increases the refinery feedstock cost advantage.

We expect the Canadian dollar to continue to be tied to a modest improvement in crude oil prices and the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise benchmark lending rates. The Bank of Canada has raised its benchmark lending rate twice this year marking a notable shift for Canada towards a tighter monetary policy.



Our exposure to the light/heavy 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 our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Additional natural gas and NGLs production associated with the Acquisition will provide improved upstream integration for the fuel, solvent and blending requirements at our oil sands operations.

## **Key Priorities for the Remainder of 2017**

### ***Maintain Financial Resilience and Executional Excellence***

We remain focused on maintaining our financial resilience and flexibility while continuing to deliver safe operations, which remains a top priority. Reducing our debt position is our number one priority. Our plans to divest our legacy Conventional assets are progressing and are on track. We are targeting between \$4.0 billion and \$5.0 billion, gross, in announced asset sale agreements by the end of 2017, the proceeds of which will be used to retire the committed Bridge Facility and deleverage our balance sheet.

At September 30, 2017, through a combination of cash and our committed credit facility, we have approximately \$5.1 billion of liquidity. We believe our liquidity position and the downside protection from our commodity hedging program should provide us the financial flexibility and resilience to maximize the value we realize on our asset sales and execute on our near-term deleveraging plan.

### ***Disciplined and Value-Added Growth***

In 2017, we anticipate capital investment to be between approximately \$1.55 billion and \$1.65 billion, a decline of six percent from our guidance dated July 26, 2017, as a result of ongoing cost savings, efficiency improvements, divestiture activities, and our continued focus on capital discipline.

We intend to focus on optimizing our capital investment and development plans in the oil sands and Deep Basin for a variety of commodity price environments. We will remain disciplined with a moderate pace of growth in the oil sands that continues to focus on controlling costs and capital efficiencies. We also anticipate a disciplined development approach to the Deep Basin Assets in 2017 and anticipate ramping up our activity levels through 2020. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

### ***Cost and Margin Leadership***

We remain committed to cost and margin leadership. We plan to continue to focus on reducing costs by leveraging our increased size and scale as well as through the advancement of technologies and enhancing our base business. We believe there is an opportunity for operating cost reductions in the Deep Basin as we fully integrate these assets. Our ability to drive structural and sustainable cost and margin improvements will further support our business plan and financial resilience.

### ***Market Access***

Market access constraints for Canadian crude oil 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.

# CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) (unaudited)

For the periods ended September 30,  
(\$ millions, except per share amounts)

	Notes	Three Months Ended		Nine Months Ended	
		2017	2016 (Restated) <sup>(1)</sup>	2017	2016 (Restated) <sup>(1)</sup>
<b>Revenues</b>	1				
Gross Sales		4,453	2,949	12,102	7,689
Less: Royalties		67	4	138	7
		<b>4,386</b>	2,945	<b>11,964</b>	7,682
<b>Expenses</b>	1				
Purchased Product		1,667	1,917	5,981	4,903
Transportation and Blending		1,083	428	2,534	1,224
Operating		523	299	1,343	913
(Gain) Loss on Risk Management	23	496	(27)	9	298
Depreciation, Depletion and Amortization	7,13	552	247	1,181	692
Exploration Expense	7,12	1	1	1	2
General and Administrative		116	71	217	225
Finance Costs	5	191	97	458	292
Interest Income		(32)	(27)	(59)	(45)
Foreign Exchange (Gain) Loss, Net	6	(350)	45	(836)	(338)
Revaluation (Gain)	4	-	-	(2,524)	-
Transaction Costs	4	1	-	56	-
Re-measurement of Contingent Payment	4,15	(43)	-	(109)	-
Research Costs		6	5	15	30
(Gain) Loss on Divestiture of Assets		(1)	5	-	6
Other (Income) Loss, Net		(2)	5	(4)	7
<b>Earnings (Loss) From Continuing Operations Before Income Tax</b>		<b>178</b>	(121)	<b>3,701</b>	(527)
Income Tax Expense (Recovery)	9	(110)	(66)	621	(277)
<b>Net Earnings (Loss) From Continuing Operations</b>		<b>288</b>	(55)	<b>3,080</b>	(250)
<b>Net Earnings (Loss) From Discontinued Operations</b>	8	<b>(357)</b>	(196)	<b>(298)</b>	(386)
<b>Net Earnings (Loss)</b>		<b>(69)</b>	(251)	<b>2,782</b>	(636)
<b>Basic and Diluted Earnings (Loss) Per Share (\$)</b>	10				
Continuing Operations		0.23	(0.07)	2.91	(0.30)
Discontinued Operations		(0.29)	(0.23)	(0.29)	(0.46)
<b>Net Earnings (Loss) Per Share</b>		<b>(0.06)</b>	(0.30)	<b>2.62</b>	(0.76)

(1) The comparative periods have been restated to reflect discontinued operations as discussed in Note 8.

See accompanying Notes to Consolidated Financial Statements (unaudited).

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

For the periods ended September 30,  
(\$ millions)

	Notes	Three Months Ended		Nine Months Ended	
		2017	2016	2017	2016
<b>Net Earnings (Loss)</b>		<b>(69)</b>	(251)	<b>2,782</b>	(636)
<b>Other Comprehensive Income (Loss), Net of Tax</b>	20				
<i>Items That Will Not be Reclassified to Profit or Loss:</i>					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		<b>10</b>	3	<b>1</b>	(9)
<i>Items That May be Reclassified to Profit or Loss:</i>					
Available for Sale Financial Assets – Change in Fair Value		<b>(1)</b>	2	<b>(1)</b>	(2)
Available for Sale Financial Assets – Reclassified to Profit or Loss		-	1	-	1
Foreign Currency Translation Adjustment		<b>(148)</b>	35	<b>(290)</b>	(205)
<b>Total Other Comprehensive Income (Loss), Net of Tax</b>		<b>(139)</b>	41	<b>(290)</b>	(215)
<b>Comprehensive Income (Loss)</b>		<b>(208)</b>	(210)	<b>2,492</b>	(851)

See accompanying Notes to Consolidated Financial Statements (unaudited).



## CONSOLIDATED BALANCE SHEETS (unaudited)

As at  
(\$ millions)

	Notes	September 30, 2017	December 31, 2016
<b>Assets</b>			
<b>Current Assets</b>			
Cash and Cash Equivalents		632	3,720
Accounts Receivable and Accrued Revenues		1,609	1,838
Income Tax Receivable		6	6
Inventories	11	1,122	1,237
Risk Management	23,24	35	21
Assets Held for Sale	8	1,805	-
<b>Total Current Assets</b>		<b>5,209</b>	6,822
Exploration and Evaluation Assets	1,12	5,517	1,585
Property, Plant and Equipment, Net	1,13	29,135	16,426
Income Tax Receivable		309	124
Risk Management	23,24	2	3
Other Assets		61	56
Goodwill	14	2,339	242
<b>Total Assets</b>		<b>42,572</b>	25,258
<b>Liabilities and Shareholders' Equity</b>			
<b>Current Liabilities</b>			
Accounts Payable and Accrued Liabilities		2,009	2,266
Income Tax Payable		58	112
Risk Management	23,24	321	293
Liabilities Related to Assets Held for Sale	8	1,318	-
<b>Total Current Liabilities</b>		<b>3,706</b>	2,671
Long-Term Debt	16	12,094	6,332
Contingent Payment	15	252	-
Risk Management	23,24	29	22
Decommissioning Liabilities	17	1,109	1,847
Other Liabilities	18	184	211
Deferred Income Taxes		5,765	2,585
<b>Total Liabilities</b>		<b>23,139</b>	13,668
Shareholders' Equity		19,433	11,590
<b>Total Liabilities and Shareholders' Equity</b>		<b>42,572</b>	25,258

See accompanying Notes to Consolidated Financial Statements (unaudited).

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

(\$ millions)

	Share Capital (Note 19)	Paid in Surplus	Retained Earnings	AOCI <sup>(1)</sup> (Note 20)	Total
As at December 31, 2015	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(636)	-	(636)
Other Comprehensive Income (Loss)	-	-	-	(215)	(215)
Total Comprehensive Income (Loss)	-	-	(636)	(215)	(851)
Stock-Based Compensation Expense	-	15	-	-	15
Dividends on Common Shares	-	-	(124)	-	(124)
As at September 30, 2016	<u>5,534</u>	<u>4,345</u>	<u>747</u>	<u>805</u>	<u>11,431</u>
As at December 31, 2016	5,534	4,350	796	910	11,590
Net Earnings (Loss)	-	-	2,782	-	2,782
Other Comprehensive Income (Loss)	-	-	-	(290)	(290)
Total Comprehensive Income (Loss)	-	-	2,782	(290)	2,492
Common Shares Issued	5,506	-	-	-	5,506
Stock-Based Compensation Expense	-	9	-	-	9
Dividends on Common Shares	-	-	(164)	-	(164)
<b>As at September 30, 2017</b>	<b><u>11,040</u></b>	<b><u>4,359</u></b>	<b><u>3,414</u></b>	<b><u>620</u></b>	<b><u>19,433</u></b>

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements (unaudited).

# CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the periods ended September 30,  
(\$ millions)

	Notes	Three Months Ended		Nine Months Ended	
		2017	2016	2017	2016
<b>Operating Activities</b>					
Net Earnings (Loss)		(69)	(251)	2,782	(636)
Depreciation, Depletion and Amortization	7,13	552	659	1,371	1,569
Exploration Expense		1	1	3	2
Deferred Income Taxes	9	(182)	(111)	757	(353)
Unrealized (Gain) Loss on Risk Management	23	486	7	75	440
Unrealized Foreign Exchange (Gain) Loss	6	(440)	50	(908)	(341)
Revaluation (Gain)	4	-	-	(2,524)	-
Re-measurement of Contingent Payment	15	(43)	-	(109)	-
Loss on Discontinuance	8	603	-	603	-
(Gain) Loss on Divestiture of Assets		(1)	5	-	6
Unwinding of Discount on Decommissioning Liabilities	17	19	33	68	97
Onerous Contract Provisions, Net of Cash Paid		(2)	(4)	(7)	26
Other		58	33	(14)	78
Net Change in Other Assets and Liabilities		(19)	(13)	(75)	(59)
Net Change in Non-Cash Working Capital		(371)	(99)	137	(132)
<b>Cash From Operating Activities</b>		<b>592</b>	<b>310</b>	<b>2,159</b>	<b>697</b>
<b>Investing Activities</b>					
Acquisition, Net of Cash Acquired	4	(63)	-	(14,562)	-
Capital Expenditures – Exploration and Evaluation Assets	12	(52)	(3)	(128)	(56)
Capital Expenditures – Property, Plant and Equipment	13	(391)	(205)	(955)	(719)
Proceeds From Divestiture of Assets		939	8	939	8
Net Change in Investments and Other		(1)	-	-	-
Net Change in Non-Cash Working Capital		80	4	53	(68)
<b>Cash From (Used in) Investing Activities</b>		<b>512</b>	<b>(196)</b>	<b>(14,653)</b>	<b>(835)</b>
<b>Net Cash Provided (Used) Before Financing Activities</b>		<b>1,104</b>	<b>114</b>	<b>(12,494)</b>	<b>(138)</b>
<b>Financing Activities</b>					
Issuance of Long-Term Debt	16	-	-	3,842	-
Net Issuance (Repayment) of Revolving Long-Term Debt	16	3	-	33	-
Issuance of Debt Under Asset Sale Bridge Facility	16	-	-	3,569	-
(Repayment) of Debt Under Asset Sale Bridge Facility	16	(950)	-	(950)	-
Common Shares Issued, Net of Issuance Costs	4,19	-	-	2,899	-
Dividends Paid on Common Shares	10	(62)	(41)	(164)	(124)
Other		-	-	(2)	(1)
<b>Cash From (Used in) Financing Activities</b>		<b>(1,009)</b>	<b>(41)</b>	<b>9,227</b>	<b>(125)</b>
<b>Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency</b>		<b>48</b>	<b>(3)</b>	<b>179</b>	<b>8</b>
<b>Increase (Decrease) in Cash and Cash Equivalents</b>		<b>143</b>	<b>70</b>	<b>(3,088)</b>	<b>(255)</b>
<b>Cash and Cash Equivalents, Beginning of Period</b>		<b>489</b>	<b>3,780</b>	<b>3,720</b>	<b>4,105</b>
<b>Cash and Cash Equivalents, End of Period</b>		<b>632</b>	<b>3,850</b>	<b>632</b>	<b>3,850</b>

See accompanying Notes to Consolidated Financial Statements (unaudited).

## 1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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Cenovus Energy Inc. and its subsidiaries, (together "Cenovus" or the "Company") are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S.").

Cenovus is incorporated under the *Canada Business Corporations Act* and its shares are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of preparation for these interim Consolidated Financial Statements is found in Note 2.

On May 17, 2017, Cenovus acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") a 50 percent interest in FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets (the "Deep Basin Assets"). This acquisition increased Cenovus's interest in FCCL to 100 percent and expanded Cenovus's operating areas to include more than three million net acres of land, exploration and production assets and related infrastructure and agreements in Alberta and British Columbia. The acquisition had an effective date of January 1, 2017 (see Note 4).

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating margin. The Company's reportable segments are:

- **Oil Sands**, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Telephone Lake. The Company's interest in certain of its operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, increased from 50 percent to 100 percent on May 17, 2017.
- **Deep Basin**, which includes approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. The Deep Basin Assets were acquired on May 17, 2017.
- **Conventional**, which has been classified as a discontinued operation as the Company commenced marketing for sale its Conventional assets. This segment includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **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 relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory. The Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

The following tabular financial information presents the segmented information first by segment, then by product and geographic location.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)  
All amounts in \$ millions, unless otherwise indicated  
For the period ended September 30, 2017

**A) Results of Operations**

For the three months ended September 30,	Oil Sands		Deep Basin		Refining and Marketing	
	2017	2016	2017	2016	2017	2016
<b>Revenues</b>						
Gross Sales	2,210	793	200	-	2,161	2,245
Less: Royalties	54	4	13	-	-	-
	2,156	789	187	-	2,161	2,245
<b>Expenses</b>						
Purchased Product	-	-	-	-	1,782	2,004
Transportation and Blending	1,066	429	22	-	-	-
Operating	257	128	101	-	168	172
(Gain) Loss on Risk Management	9	(35)	-	-	-	1
<b>Operating Margin</b>	824	267	64	-	211	68
Depreciation, Depletion and Amortization	393	181	91	-	53	52
Exploration Expense	1	1	-	-	-	-
<b>Segment Income (Loss)</b>	430	85	(27)	-	158	16

For the three months ended September 30,	Corporate and Eliminations		Consolidated	
	2017	2016	2017	2016
<b>Revenues</b>				
Gross Sales	(118)	(89)	4,453	2,949
Less: Royalties	-	-	67	4
	(118)	(89)	4,386	2,945
<b>Expenses</b>				
Purchased Product	(115)	(87)	1,667	1,917
Transportation and Blending	(5)	(1)	1,083	428
Operating	(3)	(1)	523	299
(Gain) Loss on Risk Management	487	7	496	(27)
Depreciation, Depletion and Amortization	15	14	552	247
Exploration Expense	-	-	1	1
<b>Segment Income (Loss)</b>	(497)	(21)	64	80
General and Administrative	116	71	116	71
Finance Costs	191	97	191	97
Interest Income	(32)	(27)	(32)	(27)
Foreign Exchange (Gain) Loss, Net	(350)	45	(350)	45
Revaluation (Gain)	-	-	-	-
Transaction Costs	1	-	1	-
Re-measurement of Contingent Payment	(43)	-	(43)	-
Research Costs	6	5	6	5
(Gain) Loss on Divestiture of Assets	(1)	5	(1)	5
Other (Income) Loss, Net	(2)	5	(2)	5
	(114)	201	(114)	201
<b>Earnings (Loss) From Continuing Operations Before Income Tax</b>			178	(121)
Income Tax Expense (Recovery)			(110)	(66)
<b>Net Earnings (Loss) From Continuing Operations</b>			288	(55)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)  
All amounts in \$ millions, unless otherwise indicated  
For the period ended September 30, 2017

For the nine months ended September 30,	Oil Sands		Deep Basin		Refining and Marketing	
	2017	2016	2017	2016	2017	2016
<b>Revenues</b>						
Gross Sales	4,938	1,972	324	-	7,162	5,962
Less: Royalties	117	7	21	-	-	-
	<b>4,821</b>	1,965	<b>303</b>	-	<b>7,162</b>	5,962
<b>Expenses</b>						
Purchased Product	-	-	-	-	6,295	5,144
Transportation and Blending	2,511	1,228	32	-	-	-
Operating	618	359	152	-	579	557
(Gain) Loss on Risk Management	72	(165)	-	-	4	23
<b>Operating Margin</b>	<b>1,620</b>	543	<b>119</b>	-	<b>284</b>	238
Depreciation, Depletion and Amortization	836	485	136	-	162	157
Exploration Expense	1	2	-	-	-	-
<b>Segment Income (Loss)</b>	<b>783</b>	56	<b>(17)</b>	-	<b>122</b>	81

For the nine months ended September 30,	Corporate and Eliminations		Consolidated	
	2017	2016	2017	2016
<b>Revenues</b>				
Gross Sales	(322)	(245)	12,102	7,689
Less: Royalties	-	-	138	7
	<b>(322)</b>	(245)	<b>11,964</b>	7,682
<b>Expenses</b>				
Purchased Product	(314)	(241)	5,981	4,903
Transportation and Blending	(9)	(4)	2,534	1,224
Operating	(6)	(3)	1,343	913
(Gain) Loss on Risk Management	(67)	440	9	298
Depreciation, Depletion and Amortization	47	50	1,181	692
Exploration Expense	-	-	1	2
<b>Segment Income (Loss)</b>	<b>27</b>	(487)	<b>915</b>	(350)
General and Administrative	217	225	217	225
Finance Costs	458	292	458	292
Interest Income	(59)	(45)	(59)	(45)
Foreign Exchange (Gain) Loss, Net	(836)	(338)	(836)	(338)
Revaluation (Gain)	(2,524)	-	(2,524)	-
Transaction Costs	56	-	56	-
Re-measurement of Contingent Payment	(109)	-	(109)	-
Research Costs	15	30	15	30
(Gain) Loss on Divestiture of Assets	-	6	-	6
Other (Income) Loss, Net	(4)	7	(4)	7
	<b>(2,786)</b>	177	<b>(2,786)</b>	177
<b>Earnings (Loss) From Continuing Operations Before Income Tax</b>			<b>3,701</b>	(527)
Income Tax Expense (Recovery)			<b>621</b>	(277)
<b>Net Earnings (Loss) From Continuing Operations</b>			<b>3,080</b>	(250)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)  
 All amounts in \$ millions, unless otherwise indicated  
 For the period ended September 30, 2017

**B) Revenues by Product**

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
<b>Upstream</b>				
Crude Oil	2,178	784	4,845	1,953
Natural Gas <sup>(1)</sup>	79	5	151	11
NGLs	68	-	100	-
Other	18	-	28	1
<b>Refining and Marketing</b>	<b>2,161</b>	<b>2,245</b>	<b>7,162</b>	<b>5,962</b>
<b>Corporate and Eliminations</b>	<b>(118)</b>	<b>(89)</b>	<b>(322)</b>	<b>(245)</b>
<b>Revenues From Continuing Operations</b>	<b>4,386</b>	<b>2,945</b>	<b>11,964</b>	<b>7,682</b>

(1) In the three and nine months ending September 30, 2017, approximately 18 percent and 15 percent, respectively, of the natural gas produced by Cenovus's Deep Basin Assets was sold to ConocoPhillips resulting in gross sales of \$14 million and \$22 million, respectively.

**C) Geographical Information**

For the periods ended September 30,	Revenues			
	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Canada	2,577	1,328	6,753	3,330
United States	1,809	1,617	5,211	4,352
<b>Revenues From Continuing Operations</b>	<b>4,386</b>	<b>2,945</b>	<b>11,964</b>	<b>7,682</b>

As at	Non-Current Assets <sup>(1)</sup>	
	September 30, 2017	December 31, 2016
	Canada <sup>(2)</sup>	33,206
United States	3,846	4,179
<b>Consolidated</b>	<b>37,052</b>	<b>18,309</b>

(1) Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), goodwill and other assets.

(2) Non-current assets of the Conventional segment, which resides in Canada, have been reclassified as held for sale in 2017 in current assets. 2016 includes \$3.1 billion of non-current assets related to the Conventional segment.

**D) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets**

As at	E&E		PP&E	
	September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
	Oil Sands	1,877	1,564	21,997
Deep Basin	3,640	-	2,930	-
Conventional	-	21	-	3,080
Refining and Marketing	-	-	3,943	4,273
Corporate and Eliminations	-	-	265	275
<b>Consolidated</b>	<b>5,517</b>	<b>1,585</b>	<b>29,135</b>	<b>16,426</b>

As at	Goodwill		Total Assets	
	September 30, 2017	December 31, 2016	September 30, 2017	December 31, 2016
	Oil Sands	2,339	242	27,452
Deep Basin	-	-	6,700	-
Conventional	-	-	1,966	3,196
Refining and Marketing	-	-	5,115	6,613
Corporate and Eliminations	-	-	1,339	4,337
<b>Consolidated</b>	<b>2,339</b>	<b>242</b>	<b>42,572</b>	<b>25,258</b>

## E) Capital Expenditures <sup>(1)</sup>

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
<b>Capital</b>				
Oil Sands	273	110	660	476
Deep Basin	64	-	77	-
Conventional	42	41	180	114
Refining and Marketing	38	51	124	156
Corporate	21	6	37	21
<b>Capital Investment</b>	<b>438</b>	<b>208</b>	<b>1,078</b>	<b>767</b>
<b>Acquisition Capital</b>				
Oil Sands <sup>(2)</sup>	3	-	11,607	11
Deep Basin	67	-	6,694	-
<b>Total Capital Expenditures</b>	<b>508</b>	<b>208</b>	<b>19,379</b>	<b>778</b>

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

(2) In connection with the acquisition discussed in Note 4, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3, which is not reflected in the table above. The carrying value of the pre-existing interest was \$9,081 million and the estimated fair value was \$11,605 million as at May 17, 2017.

## 2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these interim Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C\$ or \$ are to Canadian dollars and references to US\$ are to U.S. dollars.

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "Interim Financial Reporting" ("IAS 34").

Certain information provided for the prior year has been reclassified to conform to the presentation adopted for the period ended September 30, 2017.

These interim Consolidated Financial Statements were approved by the Audit Committee effective November 1, 2017.

## 3. SIGNIFICANT ACCOUNTING POLICIES

### A) Accounting Policies

Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2016, which have been prepared in accordance with IFRS as issued by the IASB. These interim Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2016, except for income taxes. Clarification on our business combinations and goodwill accounting policy has been added below.

#### Income Taxes

Income taxes on earnings or loss in interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss.

#### Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the cash-generating units ("CGUs") to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.



## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended September 30, 2017

A contingent payment transferred in a business combination is measured at fair value on the date of acquisition and classified as a financial liability or equity. A contingent payment classified as a liability is re-measured at fair value at each reporting date, with changes in fair value recognized in net earnings. Payments are classified as cash used in investing activities until the cumulative payments exceed the acquisition date fair value of the liability. Cumulative payments in excess of the acquisition date fair value are classified as cash used in operating activities. Contingent payments classified as equity are not re-measured and settlements are accounted for within equity.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings.

### **B) Recent Accounting Pronouncements**

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

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning after January 1, 2017 and have not been applied in preparing the Consolidated Financial Statements for the period ended September 30, 2017. The following provides an update to the disclosure in the annual Consolidated Financial Statements for the year ended December 31, 2016.

#### **Revenue Recognition**

On May 28, 2014, the IASB issued IFRS 15, "Revenue From Contracts With Customers" ("IFRS 15") replacing IAS 11, "Construction Contracts", IAS 18, "Revenue" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The standard may be applied retrospectively or using the retrospective with cumulative effect approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plans to adopt the standard for its year ended December 31, 2018.

#### **Leases**

On January 13, 2016, the IASB issued IFRS 16, "Leases" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively.

The Company plans to apply IFRS 16 on January 1, 2019. A transition team is assessing the impacts of adopting IFRS 16 and will oversee changes to accounting systems, processes and internal controls. The estimated time and effort necessary to develop and implement required changes (including the impact to information technology systems) extends into 2018. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Consolidated Balance Sheets.

### **C) 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. Further to those areas discussed in the annual Consolidated Financial Statements for the year ended December 31, 2016, the estimation of fair values of the assets acquired and liabilities assumed in a business combination, including contingent payment and goodwill, is a key area involving significant estimates or judgments.

## 4. ACQUISITION

### A) Summary of the Acquisition

On March 29, 2017, Cenovus entered into a purchase and sale agreement with ConocoPhillips to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets in Alberta and British Columbia (the "Acquisition"). The Acquisition was completed on May 17, 2017, with an effective date of January 1, 2017.

The Acquisition provides Cenovus with control over the Company's oil sands operations, doubles the Company's oil sands production, and almost doubles the Company's proved bitumen reserves. The Deep Basin Assets provide a second core operating area with more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia.

The Acquisition has been accounted for using the acquisition method pursuant to IFRS 3, "Business Combinations" ("IFRS 3"). Under the acquisition method, assets and liabilities are recorded at their fair values on the date of acquisition and the total consideration is allocated to the tangible and intangible assets acquired and liabilities assumed. The excess of consideration given over the fair value of the net assets acquired has been recorded as goodwill.

### B) Identifiable Assets Acquired and Liabilities Assumed

The preliminary purchase price allocation is based on Management's best estimate of fair value. Upon finalizing the fair value of net assets acquired, adjustments to initial estimates, including goodwill, may be required. No significant adjustments were made to the preliminary purchase price allocation as at September 30, 2017.

The following table summarizes the recognized amounts of assets acquired and liabilities assumed at the date of the Acquisition.

As at	Notes	May 17, 2017
<b>100 Percent of the Identifiable Assets Acquired and Liabilities Assumed for FCCL</b>		
Cash		880
Accounts Receivable and Accrued Revenues		964
Inventories		303
E&E Assets	12	918
PP&E	13	22,290
Other Assets		6
Accounts Payable and Accrued Liabilities		(445)
Decommissioning Liabilities	17	(277)
Other Liabilities		(8)
Deferred Income Taxes		(2,497)
		<b>22,134</b>
<b>Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed for Deep Basin</b>		
Accounts Receivable and Accrued Revenues		16
Inventories		2
E&E Assets	12	3,639
PP&E	13	3,049
Accounts Payable and Accrued Liabilities		(12)
Decommissioning Liabilities	17	(667)
		<b>6,027</b>
<b>Total Identifiable Net Assets</b>		<b>28,161</b>

The fair value of acquired accounts receivables and accrued revenues was \$980 million, the majority of which has been collected.

### C) Total Consideration

Total consideration for the Acquisition consisted of US\$10.6 billion in cash and 208 million Cenovus common shares plus closing adjustments. At the same time, Cenovus agreed to make certain quarterly contingent payments to ConocoPhillips during the five years subsequent to May 17, 2017 if crude oil prices exceed a specific threshold. The following table summarizes the fair value of the consideration:

As at	<b>May 17, 2017</b>
Common Shares	<b>2,579</b>
Cash	<b>15,002</b>
	<b>17,581</b>
Estimated Contingent Payment (Note 15)	<b>361</b>
<b>Total Consideration</b>	<b>17,942</b>

At the date of closing, the Company issued 208 million common shares to ConocoPhillips that were accounted for at \$12.40 per share, the estimated fair value for accounting purposes.

Consideration paid in cash was US\$10.6 billion, before closing adjustments, and was financed through a bought-deal common share offering (see Note 19) and an offering in the United States for senior unsecured notes (see Note 16). In addition, Cenovus borrowed \$3.6 billion under a committed asset sale bridge credit facility. The remainder of the cash purchase price was funded with cash on hand and a draw on Cenovus's existing committed credit facility.

The estimated contingent payment related to oil sands production reflects that Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date for quarters in which the average Western Canadian Select ("WCS") crude oil price exceeds \$52.00 per barrel during the quarter. The quarterly payment will be \$6 million for each dollar that the WCS price exceeds \$52.00 per barrel. There are no maximum payment terms.

The calculation of any contingent payment 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 terms of the contingent payment agreement allow Cenovus to retain 80 percent to 85 percent of the WCS prices above \$52.00 per barrel, based on current gross production capacity at Foster Creek and Christina Lake. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

The contingent payment is accounted for as a financial option. The fair value of \$361 million on May 17, 2017 was estimated by calculating the present value of the future expected cash flows using an option pricing model, which assumes the probability distribution for WCS is based on the volatility of West Texas Intermediate ("WTI") options, volatility of Canadian-U.S. foreign exchange rate options and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 2.9 percent. The contingent payment will be re-measured at fair value at each reporting date with changes in fair value recognized in net earnings (see Note 15).

### D) Goodwill

Goodwill arising from the Acquisition has been recognized as follows:

As at	Notes	<b>May 17, 2017</b>
Total Purchase Consideration	4C	<b>17,942</b>
Fair Value of Pre-Existing 50 Percent Ownership Interest in FCCL		<b>12,316</b>
Fair Value of Identifiable Net Assets	4B	<b>(28,161)</b>
<b>Goodwill</b>		<b>2,097</b>

#### **Fair Value of Pre-Existing 50 Percent Ownership Interest in FCCL**

Prior to the Acquisition, Cenovus's 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, "Joint Arrangements" and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to Acquisition, Cenovus controls FCCL, as defined under IFRS 10, "Consolidated Financial Statements" and accordingly, FCCL has been consolidated. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings. The acquisition-date fair value of the previously held interest was \$12.3 billion and has been included in the measurement of the total consideration transferred. Cenovus recognized a non-cash revaluation gain of \$2.5 billion (\$1.8 billion, after-tax) on the re-measurement to fair value of its existing interest in FCCL.

Goodwill was recorded in connection with deferred tax liabilities arising from the difference between the purchase price allocated to the FCCL assets and liabilities based on fair value and the tax basis of these assets and liabilities. In addition, the consideration paid for FCCL included a control premium, which resulted in a higher value compared to the fair value of the net assets acquired.

#### E) Acquisition-Related Costs

The Company incurred \$56 million of Acquisition-related costs, excluding common share and debt issuance costs. These costs have been included in transaction costs in the Consolidated Statements of Earnings.

Debt issuance costs related to the Acquisition financing were \$71 million. These costs are netted against the carrying amount of the debt and amortized using the effective interest method.

#### F) Transitional Services

Under the purchase and sales agreement, Cenovus and ConocoPhillips agreed to certain transitional services where ConocoPhillips will provide certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions are in the normal course of operations and are measured at the exchange amounts.

In the nine months ended September 30, 2017, costs related to the transitional services of approximately \$28 million were recorded in general and administrative expenses.

#### G) Revenue and Profit Contribution

The acquired business contributed revenues of \$1.9 billion and net earnings of \$141 million for the period from May 17, 2017 to September 30, 2017.

If the closing of the Acquisition had occurred on January 1, 2017, Cenovus's consolidated pro forma revenue and net earnings for the nine months ended September 30, 2017 would have been \$14.0 billion and \$2.9 billion, respectively. These amounts have been calculated using results from the acquired business and adjusting them for:

- Differences in accounting policies,
- Additional finance costs that would have been incurred if the amounts drawn on the Company's committed asset sale bridge credit facility and the senior unsecured notes issued to fund the Acquisition had occurred on January 1, 2017,
- Additional depreciation, depletion and amortization ("DD&A") that would have been charged assuming the fair value adjustments to PP&E and E&E assets had applied from January 1, 2017,
- Accretion on the decommissioning liability if it had been assumed on January 1, 2017, and
- The consequential tax effects.

This pro forma information is not necessarily indicative of the results that would have been obtained if the Acquisition had actually occurred on January 1, 2017.

## 5. FINANCE COSTS

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Interest Expense - Short-Term Borrowings and Long-Term Debt	168	84	405	255
Unwinding of Discount on Decommissioning Liabilities (Note 17)	16	8	32	21
Other	7	5	21	16
	<b>191</b>	<b>97</b>	<b>458</b>	<b>292</b>

## 6. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	(380)	52	(715)	(343)
Other	(60)	(2)	(193)	2
<b>Unrealized Foreign Exchange (Gain) Loss</b>	<b>(440)</b>	<b>50</b>	<b>(908)</b>	<b>(341)</b>
<b>Realized Foreign Exchange (Gain) Loss</b>	<b>90</b>	<b>(5)</b>	<b>72</b>	<b>3</b>
	<b>(350)</b>	<b>45</b>	<b>(836)</b>	<b>(338)</b>

## 7. IMPAIRMENT CHARGES

### A) Cash-Generating Unit Impairments

#### 2017 Impairments

As at September 30, 2017, there were no CGU impairments.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no goodwill impairments for the nine months ended September 30, 2017.

#### 2016 Upstream Impairments

Due to a decline in forward commodity prices as at September 30, 2016, the Company tested its upstream CGUs for impairment. The Company determined that the carrying amount of the Northern Alberta and Suffield CGUs exceeded their recoverable amounts, resulting in an impairment loss of \$210 million and \$65 million, respectively. The Company had previously impaired the Northern Alberta CGU by \$170 million at March 31, 2016 due to the decline in forward heavy crude oil prices. The impairment was recorded as additional DD&A in the Conventional segment, which has been classified as a discontinued operation.

As at September 30, 2016, the recoverable amount of the Northern Alberta and Suffield CGUs were estimated to be approximately \$1.1 billion and \$483 million, respectively, based on the fair value less costs of disposal. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's independent qualified reserves evaluators (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. Forward prices as at September 30, 2016 used to determine future cash flows from crude oil and natural gas reserves were:

	Remainder of 2016	2017	2018	2019	2020	Average Annual % Change to 2026
WTI (US\$/barrel)	50.00	53.50	59.70	66.10	70.00	3.6%
WCS (C\$/barrel)	45.50	50.90	57.00	63.50	65.20	3.2%
AECO (C\$/Mcf) <sup>(1) (2)</sup>	2.95	3.00	3.15	3.45	3.60	3.6%

(1) Alberta Energy Company ("AECO") natural gas.

(2) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.

There were no impairments of goodwill for the nine months ended September 30, 2016.

### B) Asset Impairment

For the nine months ended September 30, 2017, \$3 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable. An impairment loss of \$1 million was recorded as exploration expense in the Oil Sands segment and the remainder was recorded in the Conventional segment, which has been classified as a discontinued operation.

For the three months ended September 30, 2016, the Company recorded an impairment loss of \$16 million related to preliminary engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount. This impairment loss was recorded as additional DD&A in the Oil Sands segment. In the second quarter of 2016, \$4 million of leasehold improvements were written off. This impairment loss was recorded as additional DD&A in the Corporate and Eliminations segment.

## 8. ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

Concurrent with the announcement of the Acquisition on March 29, 2017, Cenovus commenced marketing for sale certain non-core properties comprising its Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican Lake region, and its Suffield crude oil and natural gas assets. On June 20, 2017, the Company announced its intent to divest the remainder of its Conventional segment assets, including its Palliser asset in southern Alberta and its Weyburn oil operation in southern Saskatchewan. As a result, the Conventional segment has been classified as held for sale and a discontinued operation. The assets have been recorded at the lesser of their carrying amount and their fair value less costs to sell. No impairments were recorded on the assets held for sale as at September 30, 2017.

### A) Results of Discontinued Operations

On September 29, 2017, the Company completed the sale of its Pelican Lake heavy oil operations, as well as other miscellaneous assets in northern Alberta, for cash proceeds of \$975 million before closing adjustments. Net proceeds from the sale were applied against the Company's \$3.6 billion asset-sale bridge facility. A before tax loss on discontinuance of \$603 million (after-tax loss \$440 million) was recorded on the sale.

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
<b>Revenues</b>				
Gross Sales	331	330	1,091	898
Less: Royalties	45	35	145	88
	<b>286</b>	295	<b>946</b>	810
<b>Expenses</b>				
Transportation and Blending	44	44	149	136
Operating	118	102	343	331
Production and Mineral Taxes	4	4	14	9
(Gain) Loss on Risk Management	3	(7)	19	(57)
<b>Operating Margin</b>	<b>117</b>	152	<b>421</b>	391
Depreciation, Depletion and Amortization	-	412	190	877
Exploration Expense	-	-	2	-
Finance Costs	3	25	36	76
<b>Earnings (Loss) From Discontinued Operations Before Income Tax</b>	<b>114</b>	(285)	<b>193</b>	(562)
Current Tax Expense (Recovery)	2	26	24	86
Deferred Tax Expense (Recovery)	29	(115)	27	(262)
<b>After-tax Earnings (Loss) From Discontinued Operations</b>	<b>83</b>	(196)	<b>142</b>	(386)
<b>After-tax Loss on Discontinuance</b> <sup>(1)</sup>	<b>(440)</b>	-	<b>(440)</b>	-
<b>Net Earnings (Loss) From Discontinued Operations</b>	<b>(357)</b>	(196)	<b>(298)</b>	(386)

(1) Net of a \$163 million deferred tax recovery.

### B) Assets and Liabilities Held for Sale

As at September 30, 2017, the assets and liabilities held for sale relate to the Suffield and Palliser areas in Alberta and the Weyburn area in Saskatchewan. See Note 27 for further information on the divestiture of these assets.

As at September 30, 2017	Total
E&E Assets (Note 12)	11
PP&E (Note 13)	1,794
Decommissioning Liabilities (Note 17)	1,318

### C) Cash Flows From Discontinued Operations

Cash flows from discontinued operations reported in the consolidated statement of cash flows are:

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Cash From Operating Activities	111	121	381	293
Cash From (Used in) Investing Activities	897	(38)	759	(111)
<b>Net Cash Flow</b>	<b>1,008</b>	83	<b>1,140</b>	182

## 9. INCOME TAXES

The provision for income taxes is:

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Current Tax				
Canada	(23)	(71)	(232)	(187)
United States	(39)	-	(40)	1
<b>Total Current Tax Expense (Recovery)</b>	<b>(62)</b>	<b>(71)</b>	<b>(272)</b>	<b>(186)</b>
<b>Deferred Tax Expense (Recovery)</b>	<b>(48)</b>	<b>5</b>	<b>893</b>	<b>(91)</b>
<b>Tax Expense (Recovery) From Continuing Operations</b>	<b>(110)</b>	<b>(66)</b>	<b>621</b>	<b>(277)</b>

The following table reconciles income taxes calculated at the Canadian statutory rate with recorded income taxes:

For the periods ended September 30,	Nine Months Ended	
	2017	2016
<b>Earnings (Loss) From Continuing Operations Before Income Tax</b>	<b>3,701</b>	<b>(527)</b>
Canadian Statutory Rate	<b>27.0%</b>	<b>27.0%</b>
<b>Expected Income Tax (Recovery)</b>	<b>999</b>	<b>(142)</b>
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	(31)	(38)
Non-Taxable Capital (Gains) Losses	(148)	(46)
Non-Recognition of Capital (Gains) Losses	(121)	(46)
Adjustments Arising From Prior Year Tax Filings	(36)	(48)
Recognition of Previously Unrecognized Capital Losses	(65)	-
Non-Deductible Expenses	3	6
Other	20	37
<b>Tax Expense (Recovery) From Continuing Operations</b>	<b>621</b>	<b>(277)</b>
<b>Effective Tax Rate</b>	<b>16.8%</b>	<b>52.6%</b>

## 10. PER SHARE AMOUNTS

### A) Net Earnings (Loss) Per Share – Basic and Diluted

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
<b>Earnings (Loss) From:</b>				
Continuing Operations	288	(55)	3,080	(250)
Discontinued Operations	(357)	(196)	(298)	(386)
Net Earnings (Loss)	<b>(69)</b>	<b>(251)</b>	<b>2,782</b>	<b>(636)</b>
<b>Weighted Average Number of Shares</b> (millions)	<b>1,228.8</b>	<b>833.3</b>	<b>1,059.9</b>	<b>833.3</b>
<b>Basic and Diluted Earnings (Loss) Per Share From: (\$)</b>				
Continuing Operations	0.23	(0.07)	2.91	(0.30)
Discontinued Operations	(0.29)	(0.23)	(0.29)	(0.46)
Net Earnings (Loss) Per Share	<b>(0.06)</b>	<b>(0.30)</b>	<b>2.62</b>	<b>(0.76)</b>

### B) Dividends Per Share

For the nine months ended September 30, 2017, the Company paid dividends of \$164 million or \$0.15 per share (nine months ended September 30, 2016 – \$124 million or \$0.15 per share).

## 11. INVENTORIES

Cenovus recorded a \$3 million write-down of product inventories to net realizable value as at September 30, 2017. As at December 31, 2016, Cenovus recorded a \$4 million write-down of its product inventory.

## 12. EXPLORATION AND EVALUATION ASSETS

	<b>Total</b>
As at December 31, 2016	1,585
Additions	128
Acquisition (Note 4) <sup>(1)</sup>	4,557
Transfers to Assets Held for Sale (Note 8)	(269)
Exploration Expense (Note 7)	(3)
Change in Decommissioning Liabilities	(2)
Divestitures <sup>(1)</sup>	(479)
<b>As at September 30, 2017</b>	<b>5,517</b>

(1) In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3.

## 13. PROPERTY, PLANT AND EQUIPMENT, NET

	<b>Upstream Assets</b>		<b>Refining Equipment</b>	<b>Other <sup>(1)</sup></b>	<b>Total</b>
	<b>Development &amp; Production</b>	<b>Other Upstream</b>			
<b>COST</b>					
As at December 31, 2016	31,941	333	5,259	1,074	38,607
Additions	798	-	120	41	959
Acquisition (Note 4) <sup>(2)</sup>	25,339	-	-	-	25,339
Transfers to Assets Held for Sale (Note 8)	(19,249)	-	-	-	(19,249)
Change in Decommissioning Liabilities	(105)	-	2	(2)	(105)
Exchange Rate Movements and Other	(1)	-	(386)	-	(387)
Divestitures <sup>(2)</sup>	(12,267)	-	-	-	(12,267)
<b>As at September 30, 2017</b>	<b>26,456</b>	<b>333</b>	<b>4,995</b>	<b>1,113</b>	<b>32,897</b>
<b>ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION</b>					
As at December 31, 2016	20,088	308	1,076	709	22,181
DD&A	1,145	18	157	51	1,371
Transfers to Assets Held for Sale (Note 8)	(16,084)	-	-	-	(16,084)
Exchange Rate Movements and Other	(3)	-	(93)	-	(96)
Divestitures <sup>(2)</sup>	(3,610)	-	-	-	(3,610)
<b>As at September 30, 2017</b>	<b>1,536</b>	<b>326</b>	<b>1,140</b>	<b>760</b>	<b>3,762</b>
<b>CARRYING VALUE</b>					
As at December 31, 2016	11,853	25	4,183	365	16,426
<b>As at September 30, 2017</b>	<b>24,920</b>	<b>7</b>	<b>3,855</b>	<b>353</b>	<b>29,135</b>

(1) Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.

(2) In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3.



## 14. GOODWILL

As at	September 30, 2017	December 31, 2016
Carrying Value, Beginning of Period	242	242
Goodwill Recognized on Acquisition (Note 4)	2,097	-
<b>Carrying Value, End of Period</b>	<b>2,339</b>	<b>242</b>

The carrying amount of goodwill allocated to the Company's exploration and production CGUs is:

As at	September 30, 2017	December 31, 2016
Primrose (Foster Creek)	1,106	242
Christina Lake	1,032	-
Narrows Lake	201	-
	<b>2,339</b>	<b>242</b>

## 15. CONTINGENT PAYMENT

As at	Total
As at January 1, 2017	-
Initial Recognition on May 17, 2017 (Note 4)	361
Re-measurement <sup>(1)</sup>	(109)
Payments	-
<b>As at September 30, 2017</b>	<b>252</b>

<sup>(1)</sup> Contingent payment is carried at fair value. Changes in fair value are recorded in net earnings.

In connection with the Acquisition (see Note 4), Cenovus 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 \$52.00 per barrel during the quarter. The quarterly payment will be \$6 million for each dollar that the WCS price exceeds \$52.00 per barrel. There are no maximum payment terms. From May 17, 2017 to September 30, 2017, WCS averaged less than \$52 per barrel; therefore, no amount was payable.

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.

## 16. LONG-TERM DEBT

As at		US\$ Principal Amount September 30, 2017	September 30, 2017	December 31, 2016
Revolving Term Debt <sup>(1)</sup>	A	-	-	-
Asset Sale Bridge Credit Facility	B	-	2,650	-
U.S. Dollar Denominated Unsecured Notes	C	7,650	9,547	6,378
<b>Total Debt Principal</b>			<b>12,197</b>	6,378
Debt Discounts and Transaction Costs			(103)	(46)
Long-Term Debt			<b>12,094</b>	<b>6,332</b>

<sup>(1)</sup> Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate based loans, prime rate loans and U.S. base rate loans.

Consideration for the Acquisition (see Note 4) was partially financed through borrowings under the Company's committed asset sale bridge credit facility and an offering in the United States for senior unsecured notes, as well as its existing committed credit facility.

### A) Revolving Term Debt

On April 28, 2017, Cenovus amended its existing committed credit facility to increase the capacity of the facility by \$0.5 billion to \$4.5 billion and to extend the maturity dates. The committed credit facility consists of a \$1.2 billion tranche maturing on November 30, 2020 and a \$3.3 billion tranche maturing on November 30, 2021. As at September 30, 2017, Cenovus had \$4.5 billion available on its committed credit facility.

### B) Asset Sale Bridge Credit Facility

In connection with the Acquisition, Cenovus borrowed \$3.6 billion under a committed asset sale bridge credit facility. On September 29, 2017, the Company repaid \$950 million using proceeds from the sale of certain assets, retiring the first tranche of the facility and a portion of the second tranche. As at September 30, 2017, a \$1.75 billion tranche maturing on November 17, 2018 and a \$0.9 billion tranche maturing on May 17, 2019 remain outstanding. Cenovus expects to repay the remaining tranches through the sale of additional assets (see Note 8).

### C) Unsecured Notes

On April 7, 2017, Cenovus completed an offering in the United States for US\$2.9 billion in senior unsecured notes in three series (collectively, the "2017 Notes"), as follows:

As at	US\$ Principal Amount	September 30, 2017
4.25% due 2027	1,200	1,498
5.25% due 2037	700	873
5.40% due 2047	1,000	1,248
	2,900	3,619

In connection with the offering of the 2017 Notes, Cenovus agreed to make an exchange offer (the "Exchange Offering") for the 2017 Notes whereby the holders will be entitled to exchange the 2017 Notes for new notes with the same terms and provisions, except that the new notes will not be subject to transfer restrictions.

On October 10, 2017, Cenovus filed a base shelf prospectus that allows the Company to offer, from time to time, up to US\$7.5 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. The base shelf prospectus also allows Cenovus to conduct the Exchange Offering and ConocoPhillips to offer, 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 November 2019 and replaces the Company's US\$5.0 billion base shelf prospectus, which would have expired in March 2018. Offerings under the base shelf prospectus are subject to market conditions.

As at September 30, 2017, the Company is in compliance with all of the terms of its debt agreements.

## 17. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets, refining facilities and the crude-by-rail terminal. The aggregate carrying amount of the obligation is:

	Total
As at December 31, 2016	1,847
Liabilities Incurred	6
Liabilities Acquired (Note 4) <sup>(1)</sup>	944
Liabilities Settled	(47)
Liabilities Divested <sup>(1)</sup>	(138)
Transfers to Liabilities Related to Assets Held for Sale (Note 8)	(1,455)
Change in Estimated Future Cash Flows	(15)
Change in Discount Rate	(98)
Unwinding of Discount on Decommissioning Liabilities	68
Foreign Currency Translation	(3)
<b>As at September 30, 2017</b>	<b>1,109</b>

(1) In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and reacquired it at fair value as required by IFRS.

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 6.0 percent as at September 30, 2017 (December 31, 2016 – 5.9 percent).

## 18. OTHER LIABILITIES

As at	September 30, 2017	December 31, 2016
Employee Long-Term Incentives	39	72
Pension and Other Post-Employment Benefit Plan	76	71
Onerous Contract Provisions	36	35
Other	33	33
	<b>184</b>	<b>211</b>

## 19. SHARE CAPITAL

### A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

### B) Issued and Outstanding

As at	September 30, 2017		December 31, 2016	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Period	833,290	5,534	833,290	5,534
Common Shares Issued, Net of Issuance Costs and Tax	187,500	2,927	-	-
Common Shares Issued to ConocoPhillips	208,000	2,579	-	-
<b>Outstanding, End of Period</b>	<b>1,228,790</b>	<b>11,040</b>	<b>833,290</b>	<b>5,534</b>

In connection with the Acquisition (see Note 4), Cenovus closed a bought-deal common share financing on April 6, 2017 for 187.5 million common shares, raising gross proceeds of \$3.0 billion (\$2.9 billion net of \$101 million of share issuance costs).

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

There were no preferred shares outstanding as at September 30, 2017 (December 31, 2016 – nil).

As at September 30, 2017, there were 15 million (December 31, 2016 – 12 million) common shares available for future issuance under the stock option plan.

## 20. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Pension Plan	Foreign Currency Translation Adjustment	Available for Sale Financial Assets	Total
As at December 31, 2015	(10)	1,014	16	1,020
Other Comprehensive Income (Loss), Before Tax	(13)	(205)	(4)	(222)
Income Tax	4	-	3	7
As at September 30, 2016	(19)	809	15	805
As at December 31, 2016	(13)	908	15	910
Other Comprehensive Income (Loss), Before Tax	1	(290)	(1)	(290)
Income Tax	-	-	-	-
<b>As at September 30, 2017</b>	<b>(12)</b>	<b>618</b>	<b>14</b>	<b>620</b>

## 21. STOCK-BASED COMPENSATION PLANS

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). The following table summarizes information related to Cenovus's stock-based compensation plans:

As at September 30, 2017	Units Outstanding (thousands)	Units Exercisable (thousands)
NSRs	42,710	36,172
TSARs	154	154
PSUs	7,021	-
RSUs	6,883	-
DSUs	1,633	1,633

For the nine months ended September 30, 2017	Units Granted (thousands)	Units Vested and Paid Out (thousands)
NSRs	2,822	-
PSUs	2,228	451
RSUs	3,263	101
DSUs	126	112

Certain directors, officers or employees chose prior to December 31, 2016 to convert a portion of their remuneration, paid in the first quarter of 2017, into DSUs. The election for any particular year is irrevocable. DSUs may not be redeemed until departure from the Company. Directors also received an annual grant of DSUs.

The weighted average exercise price of NSRs and TSARs as at September 30, 2017 was \$29.68 and \$31.78, respectively.

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans:

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
NSRs	1	4	7	12
PSUs	12	7	-	7
RSUs	9	3	3	8
DSUs	6	2	(11)	4
<b>Stock-Based Compensation Expense (Recovery)</b>	<b>28</b>	16	<b>(1)</b>	31
<b>Stock-Based Compensation Costs Capitalized</b>	<b>9</b>	4	<b>5</b>	8
<b>Total Stock-Based Compensation</b>	<b>37</b>	20	<b>4</b>	39

## 22. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings, and the current and long-term portions of long-term debt. Net debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial measures consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). These measures are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Over the long term, Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times. At different points within the economic cycle, Cenovus expects these ratios may periodically be outside of the target range.

### A) Debt to Capitalization and Net Debt to Capitalization

As at	September 30, 2017	December 31, 2016
Debt	12,094	6,332
Shareholders' Equity	19,433	11,590
	<b>31,527</b>	<b>17,922</b>
<b>Debt to Capitalization</b>	<b>38%</b>	<b>35%</b>
Debt	12,094	6,332
Add (Deduct):		
Cash and Cash Equivalents	(632)	(3,720)
Net Debt	11,462	2,612
Shareholders' Equity	19,433	11,590
	<b>30,895</b>	<b>14,202</b>
<b>Net Debt to Capitalization</b>	<b>37%</b>	<b>18%</b>

### B) Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA

As at	September 30, 2017	December 31, 2016
Debt	12,094	6,332
Net Debt	11,462	2,612
Net Earnings (Loss)	2,873	(545)
Add (Deduct):		
Finance Costs	618	492
Interest Income	(66)	(52)
Income Tax Expense (Recovery)	580	(382)
DD&A	1,300	1,498
E&E Impairment	3	2
Unrealized (Gain) Loss on Risk Management	189	554
Foreign Exchange (Gain) Loss, Net	(696)	(198)
Revaluation (Gain)	(2,524)	-
Re-measurement of Contingent Payment	(109)	-
Loss on Discontinuance	603	-
(Gain) Loss on Divestitures of Assets	-	6
Other (Income) Loss, Net	23	34
Adjusted EBITDA <sup>(1)</sup>	<b>2,794</b>	<b>1,409</b>
<b>Debt to Adjusted EBITDA</b>	<b>4.3x</b>	<b>4.5x</b>
<b>Net Debt to Adjusted EBITDA</b>	<b>4.1x</b>	<b>1.9x</b>

(1) Calculated on a trailing twelve-month basis. Includes discontinued operations.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended September 30, 2017

As at September 30, 2017, Cenovus's debt to adjusted EBITDA and net debt to adjusted EBITDA are 4.3x and 4.1x, respectively. These ratios are well outside of the Company's target range. However, it is important to note that adjusted EBITDA is calculated on a rolling twelve-month basis and as such, only includes the financial results from the Deep Basin Assets and the additional 50 percent of FCCL for the period May 17, 2017 to September 30, 2017. Debt and net debt are presented as at September 30, 2017; therefore, the ratios are fully burdened by the debt issued to finance the Acquisition. If adjusted EBITDA reflected a full twelve months of earnings from the acquired assets, Cenovus's debt and net debt to adjusted EBITDA ratios would be substantially lower.

Cenovus will maintain a high level of capital discipline and manage its capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may, among other actions, adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facility or repay existing debt.

Cenovus has in place a committed credit facility that consists of a \$1.2 billion tranche maturing on November 30, 2020 and a \$3.3 billion tranche maturing on November 30, 2021. As at September 30, 2017, Cenovus had \$4.5 billion available on its committed credit facility. Under the committed credit facility, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. The Company is well below this limit.

On October 10, 2017, Cenovus filed a US\$7.5 billion base shelf prospectus. The base shelf prospectus expires in November 2019 and replaces the Company's previous base shelf prospectus, which would have expired in March 2018. Offerings under the base shelf prospectus are subject to market conditions.

As at September 30, 2017, Cenovus is in compliance with all of the terms of its debt agreements.

## 23. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, available for sale financial assets, long-term receivables, contingent payment, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

### A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at September 30, 2017, the carrying value of Cenovus's debt was \$12,094 million and the fair value was \$12,371 million (December 31, 2016 carrying value – \$6,332 million, fair value – \$6,539 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

	<b>Total</b>
As at December 31, 2016	<b>35</b>
Acquisition of Investments	<b>2</b>
Change in Fair Value <sup>(1)</sup>	<b>(1)</b>
<b>As at September 30, 2017</b>	<b>36</b>

<sup>(1)</sup> Changes in fair value on available for sale financial assets are recorded in other comprehensive income.

## B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil swaps and options, as well as condensate, natural gas and interest rate swaps. Crude oil, condensate and natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including interest rate yield curves (Level 2).

### Summary of Unrealized Risk Management Positions

As at	September 30, 2017			December 31, 2016		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Crude Oil	35	333	(298)	21	307	(286)
Interest Rate	2	17	(15)	3	8	(5)
<b>Total Fair Value</b>	<b>37</b>	<b>350</b>	<b>(313)</b>	<b>24</b>	<b>315</b>	<b>(291)</b>

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at	September 30, 2017	December 31, 2016
<b>Level 2 – Prices Sourced From Observable Data or Market Corroboration</b>	<b>(313)</b>	<b>(291)</b>

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to September 30:

	2017	2016
Fair Value of Contracts, Beginning of Year	(291)	271
Fair Value of Contracts Realized During the Period <sup>(1)</sup>	(47)	(199)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Period	(28)	(241)
Unamortized Premium on Put Options	33	-
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	20	(12)
<b>Fair Value of Contracts, End of Period</b>	<b>(313)</b>	<b>(181)</b>

(1) Includes realized loss of \$19 million in 2017 related to the Conventional segment which is included in Discontinued Operations.

## C) Fair Value of Contingent Payment

The contingent payment is carried at fair value on the Consolidated Balance Sheets. Fair value is estimated by calculating the present value of the future expected cash flows using an option pricing model (Level 3), which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 3.7 percent. Fair value of the contingent payment has been calculated by Cenovus's internal valuation team which consists of individuals who are knowledgeable and have experience in fair value techniques. As at September 30, 2017, the fair value of contingent payment was estimated to be \$252 million.

As at September 30, 2017, average WCS forward pricing for the remaining term of the contingent payment is US\$35.51 per barrel or C\$44.28 per barrel. The average volatility of WTI options and the Canadian-U.S. foreign exchange rates was 24 percent and nine percent, respectively. Changes in the following inputs to the option pricing model, with fluctuations in all other variables held constant, could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	Increase	Decrease
WCS Forward Prices	± \$5.00 per bbl	(218)	151
WTI Option Volatility	± five percent	(27)	22
U.S. to Canadian Dollar Foreign Exchange Rate Volatility	± five percent	2	(1)

## D) Earnings Impact of (Gains) Losses From Risk Management Positions

For the periods ended September 30,	Three Months Ended		Nine Months Ended	
	2017	2016	2017	2016
Realized (Gain) Loss <sup>(1)</sup>	10	(34)	(66)	(142)
Unrealized (Gain) Loss <sup>(2)</sup>	486	7	75	440
<b>(Gain) Loss on Risk Management</b>	<b>496</b>	<b>(27)</b>	<b>9</b>	<b>298</b>

(1) Realized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates. Excludes realized risk management losses of \$19 million in the nine months ended September 30, 2017 (nine months ended September 30, 2016 – \$57 million gain) that were classified as discontinued operations.

(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

## 24. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk. A description of the nature and extent of risks arising from the Company's financial assets and liabilities can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2016. Exposure to these risks has not changed significantly since December 31, 2016. To manage exposure to interest rate volatility, the Company entered into interest rate swap contracts related to expected future debt issuances. As at September 30, 2017, Cenovus had a notional amount of US\$400 million in interest rate swaps. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts.

### Net Fair Value of Risk Management Positions

As at September 30, 2017	Notional Volumes	Terms	Average Price	Fair Value
<b>Crude Oil Contracts</b>				
Fixed Price Contracts				
Brent Fixed Price	108,000 bbls/d	July – December 2017	US\$51.68/bbl	(61)
Brent Fixed Price	36,000 bbls/d	August – December 2017	US\$49.90/bbl	(28)
Brent Fixed Price	60,000 bbls/d	January – June 2018	US\$53.34/bbl	(37)
WTI Fixed Price	150,000 bbls/d	January – June 2018	US\$48.91/bbl	(108)
WTI Fixed Price	75,000 bbls/d	July – December 2018	US\$49.32/bbl	(39)
Brent-WTI Differential	50,000 bbls/d	July – December 2017	US\$(1.88)/bbl	(16)
Brent Put Options	55,000 bbls/d	July – December 2017	US\$53.00/bbl	4
Brent Put Options	25,000 bbls/d	January – June 2018	US\$53.00/bbl	16
Brent Collars	80,000 bbls/d	January – June 2018	US\$49.54 – US\$59.86/bbl	(14)
WTI Collars	50,000 bbls/d	July – December 2017	US\$44.84 – US\$56.47/bbl	(2)
WTI Collars	10,000 bbls/d	January – June 2018	US\$45.30 – US\$62.77/bbl	2
WCS Differential	16,000 bbls/d	January – March 2018	US\$(13.11)/bbl	1
WCS Differential	15,000 bbls/d	April – June 2018	US\$(14.05)/bbl	-
Other Financial Positions <sup>(1)</sup>				(16)
Crude Oil Fair Value Position				(298)
<b>Natural Gas Contracts</b>				
Fixed Price Contracts				
NYMEX Fixed Price	30 mmcf/d	July – December 2017	US\$3.16/Mcf	-
NYMEX Fixed Price	99 mmcf/d	August – December 2017	US\$3.11/Mcf	-
NYMEX Fixed Price	69 mmcf/d	September – December 2017	US\$3.09/Mcf	-
NYMEX Fixed Price	2 mmcf/d	October – December 2017	US\$3.25/Mcf	-
Interest Rate Swaps				(15)
<b>Total Fair Value</b>				<b>(313)</b>

(1) Other financial positions are part of ongoing operations to market the Company's production.



**Sensitivities – Risk Management Positions**

The following table summarizes the sensitivity of the fair value of Cenovus’s risk management positions to fluctuations in commodity prices and interest rates, with all other variables held constant. Management believes the fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices and interest rates on the Company’s open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

**Risk Management Positions in Place as at September 30, 2017**

	<b>Sensitivity Range</b>	<b>Increase</b>	<b>Decrease</b>
Crude Oil Commodity Price	± US\$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	<b>(511)</b>	<b>515</b>
Crude Oil Differential Price	± US\$2.50 per bbl Applied to Differential Hedges Tied to Production	<b>3</b>	<b>(3)</b>
Crude Oil Differential Price	± US\$1.00 per bbl Applied to Brent-WTI Differential	<b>6</b>	<b>(6)</b>
Natural Gas Commodity Price	± US\$1.00 per Mcf Applied to NYMEX and AECO Gas Hedges	<b>(23)</b>	<b>23</b>
Interest Rate Swaps	± 50 Basis Points	<b>43</b>	<b>(50)</b>

**25. SUPPLEMENTARY CASH FLOW INFORMATION**

The following table provides a reconciliation of cash flows arising from financing activities:

	<b>Dividends Payable</b>	<b>Current Portion of Long-Term Debt</b>	<b>Long-Term Debt</b>	<b>Share Capital</b>
As at December 31, 2015	-	-	6,525	5,534
Changes From Financing Cash Flows:				
Dividends Paid	(124)	-	-	-
Non-Cash Changes:				
Dividends Declared	124	-	-	-
Unrealized Foreign Exchange (Gain) Loss (Note 6)	-	-	(343)	-
Other	-	-	2	-
As at September 30, 2016	-	-	6,184	5,534
As at December 31, 2016	-	-	6,332	5,534
Changes From Financing Cash Flows:				
Issuance of Long-Term Debt	-	-	3,842	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	-	33	-
Issuance of Debt Under Asset Sale Bridge Facility	-	892	2,677	-
(Repayment) of Debt Under Asset Sale Bridge Facility	-	(900)	(50)	-
Common Shares Issued, Net of Issuance Costs	-	-	-	2,899
Dividends Paid	(164)	-	-	-
Non-Cash Changes:				
Common Shares Issued to ConocoPhillips	-	-	-	2,579
Deferred Taxes on Share Issuance Costs	-	-	-	28
Dividends Declared	164	-	-	-
Unrealized Foreign Exchange (Gain) Loss	-	-	(748)	-
Finance Costs	-	8	9	-
Other	-	-	(1)	-
<b>As at September 30, 2017</b>	<b>-</b>	<b>-</b>	<b>12,094</b>	<b>11,040</b>

## 26. COMMITMENTS AND CONTINGENCIES

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### A) Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, the Company has commitments related to its risk management program and an obligation to fund its defined benefit pension and other post-employment benefit plans. Additional information related to the Company's commitments can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2016.

As at September 30, 2017, total commitments were \$20.7 billion, of which \$17.2 billion were for various transportation commitments. During the nine months ended September 30, 2017, the Company's transportation commitments decreased by approximately \$9.1 billion primarily due to the Company's withdrawal from certain transportation initiatives including the cancellation of the Energy East pipeline, and use of contracts partially offset by new firm transportation agreements. In relation to the Acquisition, the Company assumed \$3.7 billion of commitments primarily consisting of transportation commitments on various pipelines.

Transportation commitments include \$7.5 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2016 – \$19.2 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.

As at September 30, 2017, there were outstanding letters of credit aggregating \$257 million issued as security for performance under certain contracts (December 31, 2016 – \$258 million).

### B) Contingencies

#### *Legal Proceedings*

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

#### *Contingent Payment*

In connection with the Acquisition, Cenovus 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 \$52.00 per barrel during the quarter. As at September 30, 2017, the estimated fair value of the contingent payment was \$252 million (see Note 15).

## 27. SUBSEQUENT EVENTS

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### A) Suffield Divestiture

On September 25, 2017, Cenovus entered into an agreement to sell its Suffield crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$512 million. The agreement includes a deferred purchase price adjustment ("DPPA") that could provide Cenovus with purchase price adjustments of up to \$36 million if the average crude oil and natural gas prices rise over the next two years.

The DPPA is a two year agreement that commences January 1, 2018. Under the purchase and sale agreement, Cenovus is entitled to receive cash for each month in which the average daily price of WTI is above US\$55 per barrel or the price of Henry Hub natural gas is above US\$3.50 per million British thermal units. The monthly DPPAs are capped at \$375 thousand and \$1.125 million for crude oil and natural gas, respectively. The DPPA will be accounted for as a financial option and fair valued at each reporting date. The fair value of the DPPA on the date of close will be included in proceeds received to determine the gain on the divestiture. As at September 30, 2017, the fair value of the DPPA was estimated to be between \$5 million and \$10 million. Excluding the DPPA, the Company anticipates a gain of approximately \$340 million.

The sale of the Suffield assets is expected to close in the fourth quarter of 2017, subject to closing conditions. Net proceeds will be applied to reduce the Company's outstanding asset sale bridge credit facility.

### B) Palliser Divestiture

On October 19, 2017, Cenovus entered into an agreement to sell its Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of \$1.3 billion. The Company anticipates a gain of approximately \$1.6 billion, after the derecognition of associated decommissioning liabilities. The sale of the Palliser assets is expected to close in the fourth quarter of 2017, subject to closing conditions. Net proceeds will be applied to reduce the Company's outstanding asset sale bridge credit facility.

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Financial Statistics

(\$ millions, except per share amounts)

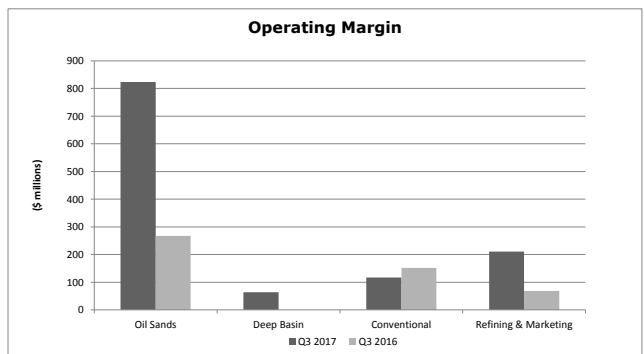
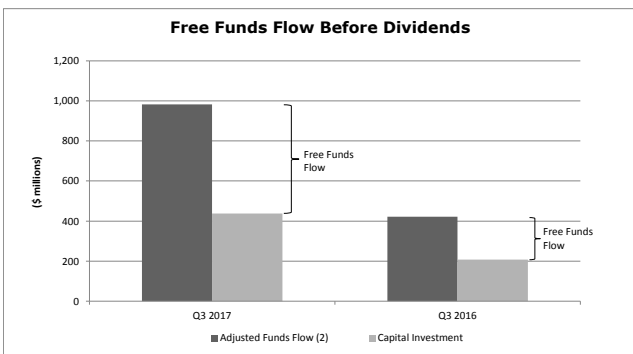
	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Revenues</b>										
Gross Sales										
Oil Sands	4,938	2,210	1,666	1,062	2,929	957	1,972	793	709	470
Deep Basin	324	200	124	-	-	-	-	-	-	-
Refining and Marketing	7,162	2,161	2,397	2,604	8,439	2,477	5,962	2,245	2,129	1,588
Corporate and Eliminations	(322)	(118)	(106)	(98)	(353)	(108)	(245)	(89)	(89)	(67)
Less: Royalties	138	67	44	27	9	2	7	4	3	-
Revenues from Continuing Operations	11,964	4,386	4,037	3,541	11,006	3,324	7,682	2,945	2,746	1,991
Conventional (Net of Royalties) - Discontinued Operations	946	286	336	324	1,128	318	810	295	261	254
<b>Total Revenues</b>	<b>12,910</b>	<b>4,672</b>	<b>4,373</b>	<b>3,865</b>	<b>12,134</b>	<b>3,642</b>	<b>8,492</b>	<b>3,240</b>	<b>3,007</b>	<b>2,245</b>

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Operating Margin <sup>(1)</sup></b>										
Oil Sands	1,620	824	544	252	877	334	543	267	231	45
Deep Basin	119	64	55	-	-	-	-	-	-	-
Refining and Marketing	284	211	20	53	346	108	238	68	193	(23)
Operating Margin from Continuing Operations	2,023	1,099	619	305	1,223	442	781	335	424	22
Conventional - Discontinued Operations	421	117	159	145	544	153	391	152	117	122
<b>Total Operating Margin</b>	<b>2,444</b>	<b>1,216</b>	<b>778</b>	<b>450</b>	<b>1,767</b>	<b>595</b>	<b>1,172</b>	<b>487</b>	<b>541</b>	<b>144</b>

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Adjusted Funds Flow <sup>(2)</sup></b>										
<b>Total Cash From Operating Activities</b>	<b>2,159</b>	<b>592</b>	<b>1,239</b>	<b>328</b>	<b>861</b>	<b>164</b>	<b>697</b>	<b>310</b>	<b>205</b>	<b>182</b>
Deduct (Add Back):										
Net Change in Other Assets and Liabilities	(75)	(19)	(25)	(31)	(91)	(32)	(59)	(13)	(17)	(29)
Net Change in Non-Cash Working Capital	137	(371)	472	36	(471)	(339)	(132)	(99)	(218)	185
<b>Total Adjusted Funds Flow</b>	<b>2,097</b>	<b>982</b>	<b>792</b>	<b>323</b>	<b>1,423</b>	<b>535</b>	<b>888</b>	<b>422</b>	<b>440</b>	<b>26</b>
Total Per Share - Basic and Diluted	1.98	0.80	0.71	0.39	1.71	0.64	1.07	0.51	0.53	0.03

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Earnings</b>										
<b>Operating Earnings (Loss) from Continuing Operations <sup>(3)</sup></b>	<b>558</b>	<b>253</b>	<b>344</b>	<b>(39)</b>	<b>(291)</b>	<b>21</b>	<b>(312)</b>	<b>(40)</b>	<b>(3)</b>	<b>(269)</b>
Per Share from Continuing Operations - Diluted	0.53	0.21	0.31	(0.05)	(0.35)	0.03	(0.37)	(0.05)	-	(0.32)
<b>Total Operating Earnings (Loss) <sup>(3)</sup></b>	<b>699</b>	<b>340</b>	<b>398</b>	<b>(39)</b>	<b>(377)</b>	<b>321</b>	<b>(698)</b>	<b>(236)</b>	<b>(39)</b>	<b>(423)</b>
Total Per Share - Diluted	0.66	0.28	0.36	(0.05)	(0.45)	0.39	(0.84)	(0.28)	(0.05)	(0.51)
<b>Net Earnings (Loss) from Continuing Operations</b>	<b>3,080</b>	<b>288</b>	<b>2,581</b>	<b>211</b>	<b>(459)</b>	<b>(209)</b>	<b>(250)</b>	<b>(55)</b>	<b>(231)</b>	<b>36</b>
Per Share from Continuing Operations - Basic and Diluted	2.91	0.23	2.32	0.25	(0.55)	(0.25)	(0.30)	(0.07)	(0.28)	0.04
<b>Total Net Earnings (Loss)</b>	<b>2,782</b>	<b>(69)</b>	<b>2,640</b>	<b>211</b>	<b>(545)</b>	<b>91</b>	<b>(636)</b>	<b>(251)</b>	<b>(267)</b>	<b>(118)</b>
Total Per Share - Basic and Diluted	2.62	(0.06)	2.37	0.25	(0.65)	0.11	(0.76)	(0.30)	(0.32)	(0.14)

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Net Capital Investment <sup>(4)</sup> (\$ millions)</b>										
Oil Sands										
Foster Creek	312	122	120	70	263	52	211	54	68	89
Christina Lake	272	132	77	63	282	60	222	47	61	114
Other Oil Sands	76	19	18	39	59	16	43	9	10	24
Total Oil Sands	660	273	215	172	604	128	476	110	139	227
Deep Basin	77	64	13	-	-	-	-	-	-	-
Conventional	180	42	50	88	171	57	114	41	34	39
Refining and Marketing	124	38	40	46	220	64	156	51	53	52
Corporate	37	21	9	7	31	10	21	6	10	5
Capital Investment	1,078	438	327	313	1,026	259	767	208	236	323
Acquisitions <sup>(4)</sup>	18,301	70	18,231	-	11	-	11	-	11	-
Divestitures <sup>(4)</sup>	(943)	(943)	-	-	(8)	-	(8)	(8)	-	-
Net Acquisition and Divestiture Activity	17,358	(873)	18,231	-	3	-	3	(8)	11	-
<b>Net Capital Investment</b>	<b>18,436</b>	<b>(435)</b>	<b>18,558</b>	<b>313</b>	<b>1,029</b>	<b>259</b>	<b>770</b>	<b>200</b>	<b>247</b>	<b>323</b>



<sup>(1)</sup> Operating Margin is an additional subtotal found in Note 1 of the 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.

<sup>(2)</sup> 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. Net change in other assets and liabilities is composed of site restoration costs and pension funding. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale.

<sup>(3)</sup> Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, revaluation gain, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

<sup>(4)</sup> In connection with the Acquisition that was completed in the second quarter of 2017, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3, which is not reflected in the table above. The carrying value of the pre-existing interest was \$9,081 million and the fair value was \$11,605 million as at May 17, 2017.

**SUPPLEMENTAL INFORMATION (unaudited)**

**Financial Statistics (continued)**

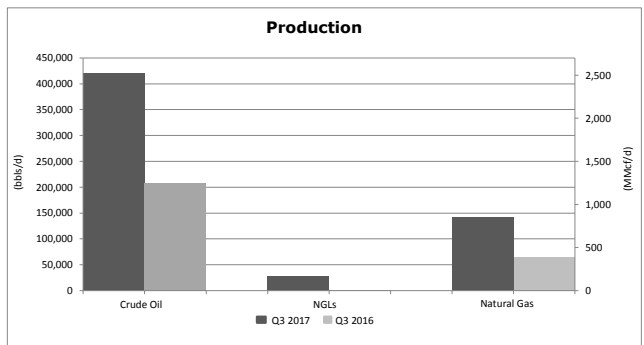
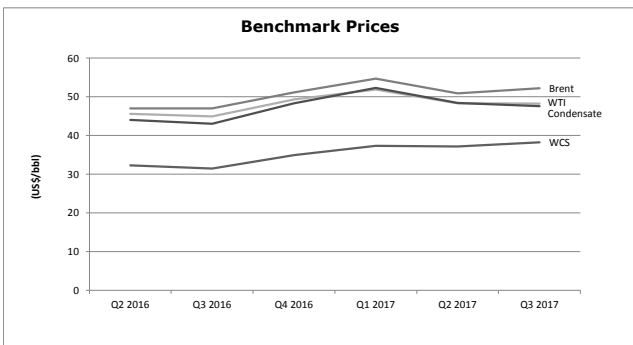
Financial Metrics (Non-GAAP Measures)	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
Net Debt to Adjusted EBITDA <sup>(1) (3)</sup>	4.1x	4.1x	6.1x	1.6x	1.9x	1.9x	2.0x	2.0x	1.9x	1.3x
Debt to Adjusted EBITDA <sup>(2) (3)</sup>	4.3x	4.3x	6.4x	3.7x	4.5x	4.5x	5.3x	5.3x	4.8x	3.6x
Return on Capital Employed <sup>(4)</sup>	13%	13%	12%	0%	(2)%	(2)%	(6)%	(6)%	6%	8%
Return on Common Equity <sup>(5)</sup>	19%	19%	17%	(2)%	(5)%	(5)%	(10)%	(10)%	7%	10%

Income Tax & Exchange Rates	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Effective Tax Rates Using:</b>										
Net Earnings	15.5%				41.2%					
Operating Earnings, Excluding Divestitures	5.9%				33.0%					
<b>Foreign Exchange Rates (US\$ per C\$1)</b>										
Average	0.766	0.798	0.744	0.756	0.755	0.750	0.757	0.766	0.776	0.728
Period End	0.801	0.801	0.771	0.751	0.745	0.745	0.762	0.762	0.769	0.771

Common Share Information	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
Common Shares Outstanding (millions)										
Period End	1,228.8	1,228.8	1,228.8	833.3	833.3	833.3	833.3	833.3	833.3	833.3
Average - Basic and Diluted	1,059.9	1,228.8	1,113.3	833.3	833.3	833.3	833.3	833.3	833.3	833.3
Dividends (\$ per share)	0.15	0.05	0.05	0.05	0.20	0.05	0.15	0.05	0.05	0.05
Closing Price - TSX (C\$ per share)	12.51	12.51	9.56	15.05	20.30	20.30	18.83	18.83	17.87	16.90
- NYSE (US\$ per share)	10.02	10.02	7.37	11.30	15.13	15.13	14.37	14.37	13.82	13.00
Share Volume Traded (millions)	2,205.0	804.1	907.7	493.2	1,491.7	322.6	1,169.1	313.0	373.3	482.8

**Operating Statistics - Before Royalties**

Upstream Production Volumes	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Crude Oil and Natural Gas Liquids (bbls/d)</b>										
Oil Sands										
Foster Creek	114,632	154,363	107,859	80,866	70,244	81,588	66,435	73,798	64,544	60,882
Christina Lake	154,634	208,131	153,953	100,635	79,449	82,808	78,321	79,793	78,060	77,093
	269,266	362,494	261,812	181,501	149,693	164,396	144,756	153,591	142,604	137,975
Deep Basin										
Light and Medium Oil	3,208	6,494	3,059	-	-	-	-	-	-	-
Natural Gas Liquids <sup>(6)</sup>	13,498	26,370	13,835	-	-	-	-	-	-	-
	16,706	32,864	16,894	-	-	-	-	-	-	-
Conventional										
Heavy Oil	26,466	25,549	26,593	27,277	29,185	28,913	29,276	28,096	28,500	31,247
Light and Medium Oil	26,430	26,947	27,233	25,089	25,915	25,065	26,200	25,311	26,177	27,121
Natural Gas Liquids <sup>(6)</sup>	1,128	1,201	1,132	1,047	1,065	1,177	1,027	1,074	799	1,208
	54,024	53,697	54,958	53,413	56,165	55,155	56,503	54,481	55,476	59,576
Total Crude Oil and Natural Gas Liquids	339,996	449,055	333,664	234,914	205,858	219,551	201,259	208,072	198,080	197,551
<b>Natural Gas (MMcf/d)</b>										
Oil Sands	11	6	12	15	17	17	17	18	18	17
Deep Basin	251	495	253	-	-	-	-	-	-	-
Conventional	351	350	355	348	377	362	382	374	381	391
Total Natural Gas	613	851	620	363	394	379	399	392	399	408
<b>Total Production <sup>(7)</sup> (BOE/d)</b>	442,143	590,851	436,929	295,414	271,525	282,718	267,759	273,405	264,580	265,551



<sup>(1)</sup> Net debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents.

<sup>(2)</sup> Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt.

<sup>(3)</sup> Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, revaluation gain, remeasurement gains (losses) on contingent consideration, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis.

<sup>(4)</sup> Return on capital employed is calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.

<sup>(5)</sup> Return on common equity is calculated, on a trailing twelve-month basis, as net earnings divided by average shareholders' equity.

<sup>(6)</sup> Natural gas liquids include condensate volumes.

<sup>(7)</sup> Natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six thousand cubic feet ("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 to 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.

**SUPPLEMENTAL INFORMATION** (unaudited)

**Operating Statistics - Before Royalties (continued)**

Selected Average Benchmark Prices	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Crude Oil Prices (US\$/bbl)</b>										
Brent	52.59	52.18	50.92	54.66	45.04	51.13	43.01	46.98	46.97	35.08
West Texas Intermediate ("WTI")	49.47	48.21	48.29	51.91	43.32	49.29	41.33	44.94	45.59	33.45
Differential Brent - WTI	3.12	3.97	2.63	2.75	1.72	1.84	1.68	2.04	1.38	1.63
Western Canadian Select ("WCS")	37.59	38.27	37.16	37.33	29.48	34.97	27.65	31.44	32.29	19.21
WCS (C\$)	49.07	47.96	49.95	49.38	39.05	46.63	36.35	41.04	41.61	26.39
Mixed Sweet Blend (US\$)	46.57	45.32	46.03	48.37	40.11	46.18	38.08	41.99	42.51	29.76
Differential WTI - WCS	11.88	9.94	11.13	14.58	13.84	14.32	13.68	13.50	13.30	14.24
Condensate (CS @ Edmonton)	49.44	47.61	48.44	52.26	42.47	48.33	40.51	43.07	44.07	34.39
Differential WTI - Condensate (Premium)/Discount	0.03	0.60	(0.15)	(0.35)	0.85	0.96	0.82	1.87	1.52	(0.94)
<b>Refining Margins 3-2-1 Crack Spreads <sup>(1)</sup> (US\$/bbl)</b>										
Chicago	15.33	19.66	14.78	11.54	13.07	10.96	13.77	14.58	17.15	9.58
Group 3	15.89	20.20	14.27	13.18	12.27	10.95	12.71	14.56	13.03	10.52
<b>Natural Gas Prices</b>										
AECO (C\$/Mcf)	2.58	2.04	2.77	2.94	2.09	2.81	1.85	2.20	1.25	2.11
NYMEX (US\$/Mcf)	3.17	3.00	3.18	3.32	2.46	2.98	2.29	2.81	1.95	2.09
Differential NYMEX - AECO (US\$/Mcf)	1.21	1.39	1.13	1.10	0.89	0.86	0.89	1.13	0.99	0.56

Average Royalty Rates (Excluding Realized Gain (Loss) on Risk Management)	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Oil Sands</b>										
Foster Creek	8.4%	9.1%	7.3%	8.5%	0.0%	(0.9)%	0.5%	0.8%	1.0%	(4.9)%
Christina Lake	2.1%	1.6%	2.6%	2.7%	1.6%	1.8%	1.4%	1.6%	1.2%	1.2%
<b>Deep Basin</b>										
Crude Oil	15.2%	14.5%	17.4%	-	-	-	-	-	-	-
Natural Gas Liquids	9.7%	10.0%	9.2%	-	-	-	-	-	-	-
Natural Gas	3.7%	3.5%	4.1%	-	-	-	-	-	-	-
<b>Conventional Oil</b>										
Pelican Lake	18.9%	19.6%	17.4%	19.8%	12.5%	11.9%	12.8%	14.1%	14.3%	8.3%
Weyburn	26.3%	24.8%	25.8%	28.3%	23.6%	28.3%	21.6%	23.0%	23.9%	16.6%
Other	13.0%	13.8%	12.7%	12.4%	12.8%	19.3%	10.1%	10.4%	8.6%	12.0%
Natural Gas Liquids	12.8%	12.2%	13.0%	13.3%	13.5%	12.2%	14.3%	12.0%	15.0%	16.1%
Natural Gas	5.1%	5.1%	5.2%	4.8%	4.6%	5.3%	4.2%	4.5%	3.7%	4.3%

Oil Sands Netbacks <sup>(2)</sup> (Excluding Realized Gain (Loss) on Risk Management)	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Heavy Oil - Foster Creek (\$/bbl)</b>										
Sales Price	42.22	41.57	44.38	40.62	30.32	38.59	26.97	33.61	33.40	11.82
Royalties	2.80	2.98	2.49	2.83	(0.01)	(0.27)	0.10	0.19	0.23	(0.16)
Transportation and Blending	9.01	8.68	10.44	7.72	8.84	7.37	9.43	8.38	11.44	8.70
Operating	10.49	9.53	12.31	9.99	10.55	10.60	10.52	9.63	10.15	12.05
Netback	19.92	20.38	19.14	20.08	10.94	20.89	6.92	15.41	11.58	(8.77)
<b>Heavy Oil - Christina Lake (\$/bbl)</b>										
Sales Price	37.47	38.84	36.54	35.86	25.30	34.78	22.01	29.11	28.31	8.85
Royalties	0.71	0.55	0.85	0.86	0.33	0.56	0.25	0.41	0.28	0.05
Transportation and Blending	4.12	4.14	4.10	4.13	4.68	4.08	4.89	4.49	4.90	5.28
Operating	6.80	6.08	7.04	8.08	7.48	8.15	7.24	7.72	6.35	7.61
Netback	25.84	28.07	24.55	22.79	12.81	21.99	9.63	16.49	16.78	(4.09)
<b>Total Heavy Oil - Oil Sands (\$/bbl)</b>										
Sales Price	39.52	40.02	39.73	38.08	27.64	36.67	24.28	31.30	30.59	10.13
Royalties	1.61	1.60	1.52	1.78	0.17	0.14	0.18	0.30	0.26	(0.04)
Transportation and Blending	6.23	6.11	6.68	5.81	6.62	5.71	6.96	6.39	7.84	6.75
Operating	8.40	7.58	9.19	8.97	8.91	9.37	8.74	8.65	8.06	9.52
Netback	23.28	24.73	22.34	21.52	11.94	21.45	8.40	15.96	14.43	(6.10)

Deep Basin Netbacks <sup>(2)</sup> (Excluding Realized Gain (Loss) on Risk Management)	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Total Deep Basin <sup>(3)</sup> (\$/BOE)</b>										
Sales Price	19.07	17.61	21.94	-	-	-	-	-	-	-
Royalties	1.34	1.28	1.45	-	-	-	-	-	-	-
Transportation and Blending	1.96	1.96	1.96	-	-	-	-	-	-	-
Operating	8.95	9.00	8.84	-	-	-	-	-	-	-
Production and Mineral Taxes	0.03	0.03	0.03	-	-	-	-	-	-	-
Netback	6.79	5.34	9.66	-	-	-	-	-	-	-

<sup>(1)</sup> The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and on a last in, first out accounting basis ("LIFO").

<sup>(2)</sup> 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. Netbacks reflect our margin on a per-barrel basis of unblended crude oil. 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 write-downs of product inventory until the product is sold. The crude oil 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. The reconciliation of the financial components of each Netback to Operating Margin can be found in our quarterly and annual Management's Discussion and Analysis and our Annual Information Form.

<sup>(3)</sup> Natural gas volumes have been converted to BOE on the basis of six Mcf to one 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 to 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.

**SUPPLEMENTAL INFORMATION (unaudited)**

**Operating Statistics - Before Royalties (continued)**

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Conventional Netbacks</b> <sup>(1)</sup> (Excluding Realized Gain (Loss) on Risk Management)										
<b>Heavy Oil - Conventional</b> (\$/bbl)										
Sales Price	47.46	48.01	46.67	47.77	35.82	40.72	34.18	40.50	36.77	25.99
Royalties	6.72	7.04	6.15	7.03	3.31	4.08	3.06	3.97	3.95	1.40
Transportation and Blending	4.44	5.45	4.48	3.40	4.60	4.90	4.50	4.86	3.85	4.77
Operating	14.30	15.50	14.56	12.86	13.38	14.69	12.94	12.43	12.34	13.98
Production and Mineral Taxes	0.01	0.01	0.01	0.02	0.01	0.01	-	0.01	0.01	-
Netback	21.99	20.01	21.47	24.46	14.52	17.04	13.68	19.23	16.62	5.84
<b>Light and Medium Oil</b> (\$/bbl)										
Sales Price	54.97	51.91	56.40	56.84	46.48	55.35	43.66	48.97	48.09	34.36
Royalties	11.47	10.22	11.58	12.75	9.28	14.87	7.50	8.91	8.52	5.18
Transportation and Blending	2.79	2.85	2.82	2.70	2.73	2.69	2.74	2.71	2.77	2.73
Operating	16.68	17.19	16.08	16.77	15.65	16.05	15.52	13.94	16.21	16.34
Production and Mineral Taxes	1.77	1.54	1.85	1.95	1.24	1.50	1.15	1.48	1.18	0.82
Netback	22.26	20.11	24.07	22.67	17.58	20.24	16.75	21.93	19.41	9.29
<b>Natural Gas Liquids</b> (\$/bbl)										
Sales Price	42.24	38.12	41.06	48.35	31.16	40.79	27.45	29.71	28.11	24.99
Royalties	5.42	4.66	5.32	6.42	4.21	4.97	3.92	3.58	4.20	4.03
Netback	36.82	33.46	35.74	41.93	26.95	35.82	23.53	26.13	23.91	20.96
<b>Natural Gas</b> (\$/Mcf)										
Sales Price	2.58	1.94	2.80	3.00	2.33	3.00	2.11	2.49	1.52	2.31
Royalties	0.13	0.10	0.14	0.14	0.10	0.15	0.08	0.10	0.05	0.09
Transportation and Blending	0.11	0.11	0.08	0.13	0.11	0.12	0.11	0.10	0.14	0.10
Operating	1.22	1.19	1.15	1.31	1.12	1.20	1.09	1.03	1.05	1.20
Production and Mineral Taxes	0.01	0.01	0.01	0.02	-	-	-	0.01	-	-
Netback	1.11	0.53	1.42	1.40	1.00	1.53	0.83	1.25	0.28	0.92
<b>Total Conventional</b> <sup>(2)</sup> (\$/BOE)										
Sales Price	32.54	29.94	33.53	34.19	26.54	31.98	24.79	28.59	24.49	21.47
Royalties	4.73	4.45	4.69	5.07	3.18	4.77	2.67	3.24	3.01	1.81
Transportation and Blending	2.03	2.26	2.00	1.82	2.08	2.17	2.05	2.09	1.96	2.09
Operating	11.08	11.38	10.85	10.99	10.23	10.92	10.01	9.30	9.89	10.79
Production and Mineral Taxes	0.47	0.42	0.47	0.51	0.27	0.31	0.26	0.35	0.27	0.16
Netback	14.23	11.43	15.52	15.80	10.78	13.81	9.80	13.61	9.36	6.62

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Consolidated Netbacks</b> <sup>(1)</sup> (Excluding Realized Gain (Loss) on Risk Management)										
<b>Total Consolidated</b> <sup>(2)</sup> (\$/BOE)										
Sales Price	34.89	33.71	35.58	36.37	27.01	34.53	24.37	29.98	27.56	15.43
Royalties	2.37	2.08	2.34	3.06	1.49	2.06	1.29	1.55	1.51	0.82
Transportation and Blending	4.56	4.56	4.78	4.20	4.56	4.20	4.69	4.51	5.07	4.51
Operating	9.18	8.59	9.59	9.80	9.51	10.05	9.32	8.92	8.89	10.14
Production and Mineral Taxes	0.12	0.08	0.13	0.20	0.12	0.13	0.12	0.15	0.12	0.08
Netback	18.66	18.40	18.74	19.11	11.33	18.09	8.95	14.85	11.97	(0.12)

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Realized Gain (Loss) on Risk Management</b>										
Total Crude Oil (\$/bbl)	(1.06)	(0.37)	0.39	(4.55)	3.24	0.91	4.08	2.15	1.97	8.21
Total Production <sup>(2)</sup> (\$/BOE)	(0.77)	(0.24)	0.28	(3.56)	2.44	0.70	3.05	1.63	1.46	6.08

	2017				2016					
	YTD	Q3	Q2	Q1	Year	Q4	Q3 YTD	Q3	Q2	Q1
<b>Refinery Operations</b> <sup>(3)</sup>										
Crude Oil Capacity (Mbbbls/d)	460	460	460	460	460	460	460	460	460	460
Crude Oil Runs (Mbbbls/d)	439	462	449	406	444	421	452	463	458	435
Heavy Oil	205	213	201	200	233	223	237	241	228	241
Light/Medium	234	249	248	206	211	198	215	222	230	194
Crude Utilization	95%	100%	98%	88%	97%	92%	98%	101%	100%	95%
Refined Products (Mbbbls/d)	467	490	476	433	471	448	479	494	483	460

<sup>(1)</sup> 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. Netbacks reflect our margin on a per-barrel basis of unblended crude oil. 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 write-downs of product inventory until the product is sold. The crude oil 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. The reconciliation of the financial components of each Netback to Operating Margin can be found in our quarterly and annual Management's Discussion and Analysis and our Annual Information Form.

<sup>(2)</sup> Natural gas volumes have been converted to BOE on the basis of six Mcf to one 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 to 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.

<sup>(3)</sup> Represents 100% of the Wood River and Borger refinery operations.

## **ADVISORY**

### **FINANCIAL INFORMATION**

#### **Basis of Presentation**

Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS).

### **OIL AND GAS INFORMATION**

The estimates of reserves were prepared effective December 31, 2016 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 McDaniel & Associates Consultants Ltd. January 1, 2017 price forecast. 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, 2016 and our Statement of Contingent and Prospective Resources.

Barrels of Oil Equivalent – Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (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.

### **NON-GAAP MEASURES AND ADDITIONAL SUBTOTAL**

The following measures do not have a standardized meaning as prescribed by IFRS and therefore are considered non-GAAP measures. Readers should not consider these measures in isolation or as a substitute for analysis of Cenovus's results as reported under IFRS. These measures are defined differently by different companies in the oil and gas industry and may not be comparable to similar measures presented by other issuers.

Adjusted Funds Flow is 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. Net change in other assets and liabilities is composed of site restoration costs and pension funding. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale.

Free Funds Flow is defined as Adjusted Funds Flow less capital investment.

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

Debt is defined as short-term borrowings and long-term debt, including the current portion. Net debt is defined as debt net of cash and cash equivalents.

Operating Margin is an additional subtotal found in Note 1 and Note 8 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of Cenovus's assets for comparability of its 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.

## FORWARD-LOOKING INFORMATION

This quarterly report 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 United States Private Securities Litigation Reform Act of 1995, about Cenovus's current expectations, estimates and projections about the future, based on certain assumptions made by the Company in light of its experience and perception of historical trends. Although Cenovus believes 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 "anticipate", "committed", "can be", "could", "estimate", "expect", "focus", "forecast", "forward", "may", "on track", "outlook", "plan", "position", "potential", "priority", "project", "should", "strategy", "target", "will" or similar expressions and includes suggestions of future outcomes, including statements about: strategy and related milestones and schedules, including expected oil sands expansion phases; projections for the remainder of 2017 and 2018 and the company's related plans and strategies; development plans; forecast operating and financial results; priorities for 2018 capital investment decisions; planned capital expenditures, including the amount and timing thereof; expected future production; forecast cost savings and sustainability thereof; planned and potential asset sales and related targets, including expected timelines, targeted proceeds and anticipated use of proceeds; and hedging strategy, including expected impacts thereof. Readers are cautioned not to place undue reliance on forward-looking information as actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2017 guidance, available at [cenovus.com](http://cenovus.com) under Investors; projected capital investment levels, the flexibility of Cenovus's capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; Cenovus's ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; Cenovus's ability to generate sufficient cash flow to meet its current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; achievement of expected impacts of the acquisition; successful integration of the Deep Basin Assets; Cenovus's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; Cenovus's ability to access sufficient capital to pursue its development plans; Cenovus's ability to complete planned and potential asset sales, including with desired transaction metrics and within the timelines it expects; forecast crude oil and natural gas prices, forecast inflation and other assumptions inherent in current guidance set out below; expected impacts of the contingent payment to ConocoPhillips, including alignment of realized Western Canadian Select ("WCS") prices and WCS prices used to calculate the contingent payment; Cenovus's projected capital investment levels, the flexibility of capital spending plans and the associated sources of funding; sustainability of achieved cost reductions, achievement of further cost reductions and sustainability thereof; Cenovus's ability to access and implement all technology necessary to achieve expected future results; Cenovus's 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.

2017 guidance, as updated November 1, 2017, assumes: Brent prices of US\$53.50/bbl, WTI prices of US\$50.00/bbl; WCS of US\$38.25/bbl; NYMEX natural gas prices of US\$3.15/MMBtu; AECO natural gas prices of \$2.40/GJ; Chicago 3-2-1 crack spread of US\$15.50/bbl; and an exchange rate of \$0.78 US\$/C\$.

Unless otherwise specifically stated or the context dictates otherwise, the financial outlook and forward-looking metrics in this quarterly report, in addition to the generally applicable assumptions described above, do not include or account for the effects or impacts of planned asset sales.

The risk factors and uncertainties that could cause actual results to differ materially, include: possible failure by Cenovus to realize the anticipated benefits of and synergies from the acquisition; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate Cenovus's assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; the effectiveness of Cenovus's risk management program, including the impact of derivative financial instruments, the success of hedging strategies and the sufficiency of Cenovus's liquidity position; the accuracy of cost estimates; commodity



prices, currency and interest rates; possible lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; market competition, including from alternative energy sources; risks inherent in 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 Cenovus's crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Debt (and Net Debt) to Adjusted EBITDA as well as Debt (and Net Debt) to Capitalization; Cenovus's ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to Cenovus's dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources, future production and future net revenue estimates; Cenovus's ability to replace and expand oil and gas reserves; Cenovus's ability to maintain its relationship with its partners and to successfully manage and operate its integrated business; reliability of Cenovus's 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, 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 crude oil into petroleum and chemical products; risks associated with technology and its application to Cenovus's business; risks associated with climate change; the timing and the costs of well and pipeline construction; Cenovus's 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 Cenovus's 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 Cenovus operates, 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 Cenovus's business, financial results and consolidated financial statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which Cenovus operates or supplies; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against Cenovus.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause 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 material risk factors, see "Risk Factors" in Cenovus's Annual Information Form (AIF) or Form 40-F for the period ended December 31, 2016, available on SEDAR at [sedar.com](http://sedar.com), on EDGAR at [sec.gov](http://sec.gov) and on Cenovus's website at [cenovus.com](http://cenovus.com), and the updates under "Risk Management" in Cenovus's most recently filed Management's Discussion and Analysis (MD&A).

## ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

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

## 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

#### Upstream Financial Results

Three Months Ended September 30, 2017 (\$ millions)	Per Interim Consolidated Financial Statements			Total Upstream
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Conventional <sup>(2)</sup>	
<b>Revenues</b>				
Gross Sales	2,210	200	331	2,741
Less: Royalties	54	13	45	112
	2,156	187	286	2,629
<b>Expenses</b>				
Transportation and Blending	1,066	22	44	1,132
Operating	257	101	118	476
Production and Mineral Taxes	-	-	4	4
<b>Netback</b>	833	64	120	1,017
(Gain) Loss on Risk Management	9	-	3	12
<b>Operating Margin</b>	824	64	117	1,005

Three Months Ended September 30, 2016 (\$ millions)	Per Interim Consolidated Financial Statements			Total Upstream
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Conventional <sup>(2)</sup>	
<b>Revenues</b>				
Gross Sales	793	-	330	1,123
Less: Royalties	4	-	35	39
	789	-	295	1,084
<b>Expenses</b>				
Transportation and Blending	429	-	44	473
Operating	128	-	102	230
Production and Mineral Taxes	-	-	4	4
<b>Netback</b>	232	-	145	377
(Gain) Loss on Risk Management	(35)	-	(7)	(42)
<b>Operating Margin</b>	267	-	152	419

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

(2) Found in Note 8 of the Interim Consolidated Financial Statements.

#### Netback Reconciliations

Three Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation	Adjustments			Per Above Table Total Upstream
		Condensate	Inventory	Other	
<b>Revenues</b>	<b>Total</b>				
Gross Sales	1,836	885	-	20	2,741
Less: Royalties	114	-	-	(2)	112
	1,722	885	-	22	2,629
<b>Expenses</b>					
Transportation and Blending	248	885	(1)	-	1,132
Operating	469	-	-	7	476
Production and Mineral Taxes	4	-	-	-	4
<b>Netback</b>	1,001	-	1	15	1,017
(Gain) Loss on Risk Management	12	-	-	-	12
<b>Operating Margin</b>	989	-	1	15	1,005

Three Months Ended September 30, 2016 (\$ millions)	Basis of Netback Calculation	Adjustments			Per Above Table Total Upstream
		Condensate	Inventory	Other	
<b>Revenues</b>	<b>Total</b>				
Gross Sales	762	358	-	3	1,123
Less: Royalties	39	-	-	-	39
	723	358	-	3	1,084
<b>Expenses</b>					
Transportation and Blending	115	358	-	-	473
Operating	227	-	-	3	230
Production and Mineral Taxes	4	-	-	-	4
<b>Netback</b>	377	-	-	-	377
(Gain) Loss on Risk Management	(41)	-	-	(1)	(42)
<b>Operating Margin</b>	418	-	-	1	419

## Total Production

### Upstream Financial Results

Nine Months Ended September 30, 2017 (\$ millions)	Per Interim Consolidated Financial Statements			Total Upstream
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Conventional <sup>(2)</sup>	
<b>Revenues</b>				
Gross Sales	4,938	324	1,091	6,353
Less: Royalties	117	21	145	283
	4,821	303	946	6,070
<b>Expenses</b>				
Transportation and Blending	2,511	32	149	2,692
Operating	618	152	343	1,113
Production and Mineral Taxes	-	-	14	14
<b>Netback</b>	1,692	119	440	2,251
(Gain) Loss on Risk Management	72	-	19	91
<b>Operating Margin</b>	1,620	119	421	2,160

Nine Months Ended September 30, 2016 (\$ millions)	Per Interim Consolidated Financial Statements			Total Upstream
	Oil Sands <sup>(1)</sup>	Deep Basin <sup>(1)</sup>	Conventional <sup>(2)</sup>	
<b>Revenues</b>				
Gross Sales	1,972	-	898	2,870
Less: Royalties	7	-	88	95
	1,965	-	810	2,775
<b>Expenses</b>				
Transportation and Blending	1,228	-	136	1,364
Operating	359	-	331	690
Production and Mineral Taxes	-	-	9	9
<b>Netback</b>	378	-	334	712
(Gain) Loss on Risk Management	(165)	-	(57)	(222)
<b>Operating Margin</b>	543	-	391	934

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

(2) Found in Note 8 of the Interim Consolidated Financial Statements.

### Netback Reconciliations

Nine Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation	Adjustments			Per Above Table
	Total	Condensate	Inventory	Other	Total Upstream
<b>Revenues</b>					
Gross Sales	4,172	2,147	-	34	6,353
Less: Royalties	284	-	-	(1)	283
	3,888	2,147	-	35	6,070
<b>Expenses</b>					
Transportation and Blending	543	2,147	-	2	2,692
Operating	1,098	-	-	15	1,113
Production and Mineral Taxes	14	-	-	-	14
<b>Netback</b>	2,233	-	-	18	2,251
(Gain) Loss on Risk Management	91	-	-	-	91
<b>Operating Margin</b>	2,142	-	-	18	2,160

Nine Months Ended September 30, 2016 (\$ millions)	Basis of Netback Calculation	Adjustments			Per Above Table
	Total	Condensate	Inventory	Other	Total Upstream
<b>Revenues</b>					
Gross Sales	1,790	1,070	-	10	2,870
Less: Royalties	95	-	-	-	95
	1,695	1,070	-	10	2,775
<b>Expenses</b>					
Transportation and Blending	345	1,070	(51)	-	1,364
Operating	684	-	-	6	690
Production and Mineral Taxes	9	-	-	-	9
<b>Netback</b>	657	-	51	4	712
(Gain) Loss on Risk Management	(223)	-	-	1	(222)
<b>Operating Margin</b>	880	-	51	3	934

## Oil Sands

Three Months Ended September 30, 2017 (\$ 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
<b>Revenues</b>								
Gross Sales	603	737	1,340	1	863	-	6	2,210
Less: Royalties	43	11	54	-	-	-	-	54
	560	726	1,286	1	863	-	6	2,156
<b>Expenses</b>								
Transportation and Blending	126	79	205	-	863	(1)	(1)	1,066
Operating	138	116	254	1	-	-	2	257
<b>Netback</b>	296	531	827	-	-	1	5	833
(Gain) Loss on Risk Management	2	7	9	-	-	-	-	9
<b>Operating Margin</b>	294	524	818	-	-	1	5	824

Three Months Ended September 30, 2016 (\$ 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
<b>Revenues</b>								
Gross Sales	236	215	451	4	337	-	1	793
Less: Royalties	1	3	4	-	-	-	-	4
	235	212	447	4	337	-	1	789
<b>Expenses</b>								
Transportation and Blending	59	33	92	-	337	-	-	429
Operating	68	57	125	2	-	-	1	128
<b>Netback</b>	108	122	230	2	-	-	-	232
(Gain) Loss on Risk Management	(16)	(18)	(34)	-	-	-	(1)	(35)
<b>Operating Margin</b>	124	140	264	2	-	-	1	267

Nine Months Ended September 30, 2017 (\$ 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
<b>Revenues</b>								
Gross Sales	1,319	1,541	2,860	7	2,060	-	11	4,938
Less: Royalties	87	30	117	-	-	-	-	117
	1,232	1,511	2,743	7	2,060	-	11	4,821
<b>Expenses</b>								
Transportation and Blending	281	170	451	-	2,060	-	-	2,511
Operating	328	280	608	6	-	-	4	618
<b>Netback</b>	623	1,061	1,684	1	-	-	7	1,692
(Gain) Loss on Risk Management	33	39	72	-	-	-	-	72
<b>Operating Margin</b>	590	1,022	1,612	1	-	-	7	1,620

Nine Months Ended September 30, 2016 (\$ 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
<b>Revenues</b>								
Gross Sales	490	476	966	9	994	-	3	1,972
Less: Royalties	2	5	7	-	-	-	-	7
	488	471	959	9	994	-	3	1,965
<b>Expenses</b>								
Transportation and Blending	172	106	278	-	994	(44)	-	1,228
Operating	192	156	348	8	-	-	3	359
<b>Netback</b>	124	209	333	1	-	44	-	378
(Gain) Loss on Risk Management	(79)	(85)	(164)	-	-	-	(1)	(165)
<b>Operating Margin</b>	203	294	497	1	-	44	1	543

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

## Deep Basin

Three Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation		Adjustments		Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total		Other		Total Deep Basin
<b>Revenues</b>					
Gross Sales	187		13		200
Less: Royalties	13		-		13
	174		13		187
<b>Expenses</b>					
Transportation and Blending	20		2		22
Operating	96		5		101
Production and Mineral Taxes	-		-		-
<b>Netback</b>	58		6		64
(Gain) Loss on Risk Management	-		-		-
<b>Operating Margin</b>	58		6		64

Nine Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation		Adjustments		Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Total		Other		Total Deep Basin
<b>Revenues</b>					
Gross Sales	305		19		324
Less: Royalties	21		-		21
	284		19		303
<b>Expenses</b>					
Transportation and Blending	30		2		32
Operating	143		9		152
Production and Mineral Taxes	-		-		-
<b>Netback</b>	111		8		119
(Gain) Loss on Risk Management	-		-		-
<b>Operating Margin</b>	111		8		119

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

## Conventional

Three Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation					Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
<b>Revenues</b>										
Gross Sales	111	131	4	246	62	308	22	-	1	331
Less: Royalties	17	26	1	44	3	47	-	-	(2)	45
	94	105	3	202	59	261	22	-	3	286
<b>Expenses</b>										
Transportation and Blending	13	7	-	20	3	23	22	-	(1)	44
Operating	35	44	-	79	39	118	-	-	-	118
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
<b>Netback</b>	46	50	3	99	17	116	-	-	4	120
(Gain) Loss on Risk Management	1	3	-	4	(1)	3	-	-	-	3
<b>Operating Margin</b>	45	47	3	95	18	113	-	-	4	117

Three Months Ended September 30, 2016 (\$ millions)	Basis of Netback Calculation					Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
<b>Revenues</b>										
Gross Sales	104	114	3	221	86	307	21	-	2	330
Less: Royalties	10	21	1	32	3	35	-	-	-	35
	94	93	2	189	83	272	21	-	2	295
<b>Expenses</b>										
Transportation and Blending	13	6	-	19	4	23	21	-	-	44
Operating	32	33	-	65	35	100	-	-	2	102
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
<b>Netback</b>	49	50	2	101	44	145	-	-	-	145
(Gain) Loss on Risk Management	(5)	(2)	-	(7)	-	(7)	-	-	-	(7)
<b>Operating Margin</b>	54	52	2	108	44	152	-	-	-	152

(1) Found in Note 8 of the Interim Consolidated Financial Statements.

## Conventional

Nine Months Ended September 30, 2017 (\$ millions)	Basis of Netback Calculation					Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
	<b>Revenues</b>									
Gross Sales	343	397	13	753	247	1,000	87	-	4	1,091
Less: Royalties	49	83	2	134	12	146	-	-	(1)	145
	294	314	11	619	235	854	87	-	5	946
<b>Expenses</b>										
Transportation and Blending	32	20	-	52	10	62	87	-	-	149
Operating	103	121	-	224	117	341	-	-	2	343
Production and Mineral Taxes	-	13	-	13	1	14	-	-	-	14
<b>Netback</b>	159	160	11	330	107	437	-	-	3	440
(Gain) Loss on Risk Management	10	10	-	20	(1)	19	-	-	-	19
<b>Operating Margin</b>	149	150	11	310	108	418	-	-	3	421

Nine Months Ended September 30, 2016 (\$ millions)	Basis of Netback Calculation					Adjustments				Per Interim Consolidated Financial Statements <sup>(1)</sup>
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
	<b>Revenues</b>									
Gross Sales	272	315	7	594	221	815	76	-	7	898
Less: Royalties	24	54	2	80	8	88	-	-	-	88
	248	261	5	514	213	727	76	-	7	810
<b>Expenses</b>										
Transportation and Blending	36	19	-	55	12	67	76	(7)	-	136
Operating	103	112	-	215	113	328	-	-	3	331
Production and Mineral Taxes	-	9	-	9	-	9	-	-	-	9
<b>Netback</b>	109	121	5	235	88	323	-	7	4	334
(Gain) Loss on Risk Management	(32)	(28)	-	(60)	1	(59)	-	-	2	(57)
<b>Operating Margin</b>	141	149	5	295	87	382	-	7	2	391

(1) Found in Note 8 of the Interim Consolidated Financial Statements.

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,	
	2017	2016	2017	2016
<b>Oil Sands</b>				
Foster Creek	157,850	76,318	114,466	66,229
Christina Lake	206,338	80,313	150,656	78,838
<b>Total Oil Sands Crude Oil</b>	364,188	156,631	265,122	145,067
<b>Natural Gas</b> (MMcf per day)	6	18	11	17
<b>Deep Basin</b>				
<b>Total Liquids</b>	32,864	-	16,706	-
<b>Natural Gas</b> (MMcf per day)	495	-	251	-
<b>Conventional</b>				
Heavy Oil	25,047	27,953	26,448	28,999
Light and Medium Oil	27,494	25,359	26,477	26,322
Natural Gas Liquids ("NGLs")	1,201	1,074	1,128	1,027
<b>Total Conventional Liquids</b>	53,742	54,386	54,053	56,348
<b>Natural Gas</b> (MMcf per day)	350	374	351	382
<b>Total Liquids Sales</b>	450,794	211,017	335,881	201,415
<b>Total Sales</b> (BOE per day)	592,591	276,350	438,028	267,915

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