

# First Quarter 2016



**cenovus**  
ENERGY

## Cenovus finishes first quarter with strong balance sheet Company's 2016 cost-reduction initiatives on target

**Calgary, Alberta (April 27, 2016)** – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) is on track to achieve its previously announced target of reducing planned capital, operating and general and administrative (G&A) spending by up to \$500 million compared with its original 2016 budget. Building on the significant cost reductions achieved in 2015, these additional spending cuts are expected to help the company remain financially resilient through this prolonged period of challenging market conditions.

"We continue to make significant structural improvements in our organization," said Brian Ferguson, Cenovus President & Chief Executive Officer. "I believe these changes will make us a cost and efficiency leader so we can drive sustainable value for our shareholders in a volatile price environment. We also remain clearly focused on the safety and reliability of our operations."

### Key developments

- Exited the first quarter of 2016 with nearly \$8 billion in liquidity, including \$3.9 billion in cash and cash equivalents and net debt to capitalization of 16%
- Reduced first quarter crude oil per-unit operating costs by 14% to \$11.08 per barrel (bbl) compared with the same period a year earlier
- Largely completed previously announced workforce reductions for 2016 of 440 staff, bringing total reductions since December 31, 2014 to 31%
- Reduced projected 2016 capital spending by \$300 million and remain on track to lower operating and G&A expenses by \$200 million, as previously announced
- On track at Foster Creek to achieve expected volumes of between 60,000 barrels per day (bbls/d) net and 65,000 bbls/d net in the first half of 2016 and then ramp up to finish the year at more than 70,000 bbls/d net, in line with guidance

Production & financial summary			
(for the period ended March 31)	2016	2015	% change
Production (before royalties)	Q1	Q1	
Oil sands (bbls/d)	137,975	144,372	-4
Conventional oil <sup>1</sup> (bbls/d)	59,576	73,648	-19
<b>Total oil</b> (bbls/d)	<b>197,551</b>	218,020	-9
Natural gas (MMcf/d)	408	462	-12
Financial			
(\$ millions, except per share amounts)			
Cash flow <sup>2</sup>	26	495	-95
Per share diluted	0.03	0.64	
Operating earnings/loss <sup>2</sup>	-423	-88	
Per share diluted	-0.51	-0.11	
Net earnings/loss	-118	-668	
Per share diluted	-0.14	-0.86	
Capital investment	323	529	-39

<sup>1</sup> Includes natural gas liquids (NGLs).

<sup>2</sup> Cash flow and operating earnings/loss are non-GAAP measures as defined in the Advisory.

## Overview

As a result of the decisive steps taken since the downturn in oil prices began more than a year and a half ago, Cenovus has been able to preserve its financial resilience even as crude oil and natural gas prices reached multi-year lows in the first quarter of this year. The company continues to focus on safe and reliable operations while executing on all aspects of its business that are within its control, including delivering strong operational performance at its two oil sands facilities.

### **Cost reductions update**

In line with its February guidance, Cenovus has reduced planned 2016 capital spending to \$1.2 billion, down \$300 million from its original budget for the year, and the company remains on track to lower its operating and G&A expenses by \$200 million.

"The cost reductions we've achieved to date and the company's continued focus on increased efficiency have put us in a strong financial position," said Ferguson. "We expect to be able to execute on our planned capital program, maintain a strong balance sheet and fund our current dividend, even with Brent crude prices in the US\$40 per barrel range through the end of 2017."

Cost reductions over the last year and a half have been achieved as a result of improvements that include more efficient drilling and well completions, better prioritization of repair and maintenance activities and reduced supplier rates, including lower chemical costs.

In the first quarter of 2016, oil sands operating costs were down \$1.47/bbl or 13% to \$9.52/bbl compared with the same period in 2015. This included a 13% decrease in non-fuel operating costs to \$7.33/bbl.

Company wide, operating and G&A costs also improved year-over-year, partly as a result of Cenovus's efforts to realign the size of its workforce to match the company's more moderate approach to spending and growth. Previously announced workforce reductions for 2016 of 440 staff are now largely complete, leaving Cenovus with approximately 31% fewer staff than it had at the end of 2014. As a result of a thorough review of employee compensation and benefit programs, the company has decided to adjust annual allowances and change some benefits to align with current industry conditions. For Cenovus's President & Chief Executive Officer as well as the company's four other highest paid executives, cash bonus compensation for 2015 was reduced and annual base salaries have remained unchanged for the last three years. Total combined compensation for these executives was approximately 15% lower in 2015 than it was in 2013. The company will continue monitoring its compensation structure and make adjustments as appropriate. Cenovus remains committed to retaining and attracting high-calibre staff through competitive compensation that is aligned with shareholder interests.

"This has been a challenging time for Cenovus, particularly when it comes to the difficult but necessary workforce reductions we've had to make in response to industry conditions and our more moderate pace of growth," said Ferguson. "Thanks to the efforts of everyone in

the company, we're on track to achieve the substantial and sustainable cost reductions we need to help us remain globally competitive, particularly with the U.S. light tight oil sector."

The full benefit of the cost-reduction initiatives Cenovus has undertaken in 2015 and so far in 2016 is expected to become increasingly evident throughout the remainder of this year. In addition, the company continues to seek opportunities across its business to further reduce capital and operating costs. For example, Cenovus is already realizing cost reductions greater than originally expected from the implementation of smaller, more efficient well pad designs. This new approach to pad construction is expected to deliver significant incremental savings over the long term.

### **Financial performance and resilience**

While Cenovus had strong operational performance in the first quarter, its financial results were significantly impacted by continued commodity price weakness. Financial performance was also affected by factors that are not expected to persist through the rest of the year. For example, refining profitability tends to be seasonally weak in the first quarter, and a recovery in crack spreads is anticipated through the second and third quarters. The timing of condensate inventory drawdowns in a falling oil price environment, combined with typically higher blend ratios during the winter months, also had a significant negative impact on realized heavy oil pricing in the first quarter. These factors are expected to improve in a rising price environment as Cenovus draws lower-priced condensate from inventory and blends it into its oil. As a result, Cenovus believes that its first quarter financial performance is not indicative of the company's potential performance for the remainder of 2016.

The year-over-year decline in West Texas Intermediate (WTI), Western Canadian Select (WCS) and AECO natural gas prices of 31%, 43%, and 28%, respectively, contributed to a 74% decrease in first quarter 2016 operating cash flow to \$144 million. Upstream operating cash flow was down by 63% to \$167 million. During the quarter, the company also recorded an asset impairment associated with its northern Alberta conventional oil assets of \$170 million due to the decline in forward crude oil and natural gas prices. In a recovering oil price environment, Cenovus expects cash flow to increase approximately \$625 million for every US\$10/bbl improvement in WTI prices.

The company's refining and marketing operations had an operating cash flow loss of \$23 million during the first quarter of 2016 compared with operating cash flow of \$95 million in the same period a year ago. This was primarily due to a 41% decline in market crack spreads driven by seasonal weakness, high storage levels for refined product and the narrowing of the Brent-WTI price differential compared with the same period a year ago.

Cenovus ended the first quarter of 2016 with cash and cash equivalents of approximately \$3.9 billion. Including cash on hand and \$4 billion in undrawn capacity under its committed credit facility, the company has nearly \$8 billion in liquidity available, with no debt maturing until the fourth quarter of 2019. At the end of the first quarter of 2016, the company's net debt to capitalization ratio was 16% compared with 27% in the same period a year earlier, and its net debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) was 1.3 times, the same as in the first quarter of 2015.

The company recently secured an extension of the \$1 billion tranche of its committed credit facility, extending the maturity date to April 2019 from November 2017. The \$3 billion tranche of Cenovus's committed credit facility remains unchanged, with a November 2019 maturity date.

Cenovus continues to hold investment-grade credit ratings from two of the three agencies that rate the company. Standard & Poor's recently reaffirmed Cenovus's investment-grade rating at BBB with a stable outlook, while DBRS has Cenovus rated at BBB (high) with a negative trend. In the first quarter, Moody's downgraded Cenovus's credit rating below investment grade to Ba2 as part of a broad energy industry review prompted by a negative revision to Moody's long-term outlook for oil prices.

"Moody's has issued a number of downgrades across our industry," said Ivor Ruste, Cenovus Executive Vice-President & Chief Financial Officer. "Due to the decisive steps we've taken over the last year and a half to strengthen our balance sheet and increase liquidity, this has had no material impact on our financial resilience or operations. We remain committed to disciplined capital spending and to further reducing our operating and administrative costs."

### **Oil production**

Production from Cenovus's oil sands and conventional oil operations was in line with the company's expectations during the first quarter. The Foster Creek and Christina Lake oil sands projects continue to perform well, with production on track to be within Cenovus's guidance range for 2016.

At Foster Creek, volumes have been trending higher since early March after declining 10% overall during the first quarter compared with the same period a year earlier. The first quarter decrease, which was anticipated, was largely due to decisions made in 2015 to conserve cash by delaying spending on new sustaining well pads and repairs and maintenance. As previously announced, the company is now increasing maintenance activities, bringing wells that were down for servicing back online, and has begun to start up new well pads which have added incremental production as of this March. Cenovus anticipates production at Foster Creek to average between 60,000 bbls/d and 65,000 bbls/d net in the first half of 2016 and between 65,000 bbls/d and 70,000 bbls/d net in the second half of the year, exiting 2016 above 70,000 bbls/d net, in line with the company's February guidance.

At Christina Lake, first quarter production increased by 1% compared with the same period in 2015. The recently completed Christina Lake optimization project added incremental production during the first quarter. In addition, the Christina Lake phase F and Foster Creek phase G expansions are largely complete, with plant commissioning and steam circulation expected to commence over the next few months and first oil anticipated in the third quarter of 2016. Together, these two expansion projects, plus the Christina Lake optimization, are expected to add approximately 100,000 bbls/d of incremental gross production capacity (50,000 bbls/d net).

## First quarter details

### Oil sands

#### Christina Lake

- Production averaged 77,093 bbls/d net in the first quarter of 2016, a slight increase from the same period a year earlier, due to the completion of the optimization project and consistent operating performance.
- Operating costs were \$7.61/bbl in the quarter, a reduction of 8% from the first quarter of 2015. Non-fuel operating costs were \$5.65/bbl, 7% lower than in the same period a year ago.
- The steam to oil ratio (SOR), the amount of steam needed to produce a barrel of oil, was 1.9 during the first quarter compared with 1.7 a year earlier.
- Netbacks, including realized hedging gains, were \$3.34/bbl in the quarter, down 80% from the same period in 2015.

#### Foster Creek

- Production averaged 60,882 bbls/d net in the first quarter of 2016, 10% lower than in the same period of 2015.
- Operating costs at Foster Creek decreased 17% to \$12.05/bbl in the quarter. Non-fuel operating costs were \$9.57/bbl, a 17% decline from a year earlier.
- The SOR was 3.0 for the first quarter compared with 2.4 in the same period of 2015.
- Netbacks, including realized hedging gains, were \$0.72/bbl for the quarter, a 95% decline from the previous year.

#### Conventional oil

- Total conventional oil production decreased 19% to 59,576 bbls/d in the first quarter of 2016 compared with the same quarter a year ago, primarily due to natural reservoir declines and the 2015 sale of Cenovus's royalty interest and mineral fee title lands business. The divested assets contributed an average of 4,700 bbls/d of production in the first quarter of 2015. The decline in production was partially offset by successful horizontal well performance in southern Alberta.
- Operating costs were \$14.78/bbl in the quarter, 10% lower than in the first quarter of 2015.

#### Natural gas

- Natural gas production averaged 408 million cubic feet per day (MMcf/d) in the first quarter of 2016, down 12% from the same period a year earlier, primarily due to expected natural declines and the company's 2015 sale of its royalty and fee land business.
- Operating costs declined 2% to \$1.23 per thousand cubic feet (Mcf) in the quarter compared with the same period a year earlier.

#### Downstream

- Cenovus's Wood River Refinery in Illinois and Borger Refinery in Texas, which are jointly owned with the operator, Phillips 66, continued to have strong operational performance in the first quarter of 2016, including:

- processing a combined average of 435,000 bbls/d gross of crude oil (95% utilization) compared with 439,000 bbls/d gross in the same period in 2015
  - producing an average of 460,000 bbls/d gross of refined products compared with 469,000 bbls/d gross a year earlier.
- Cenovus had an operating cash flow loss of \$23 million from refining and marketing in the first quarter of 2016 compared with operating cash flow of \$95 million in the same period a year earlier. Cenovus's refining operating cash flow 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 cash flow from refining would have been \$37 million higher in the first quarter of 2016 compared with \$52 million higher in the same period a year earlier.

## **Financial**

### **Dividend**

The Board of Directors has declared a second quarter dividend of \$0.05 per share, payable on June 30, 2016 to common shareholders of record as of June 15, 2016. Based on the April 26, 2016 closing share price on the Toronto Stock Exchange of \$18.87, this represents an annualized yield of about 1.1%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis.

### **Corporate and financial information**

- Operating cash flow was \$144 million in the first quarter, down 74% from the same period a year earlier, largely due to lower crude oil and natural gas sales prices, a decline in crude oil and natural gas sales volumes and an operating cash flow loss at Cenovus's refining and marketing operations. The decline was partially offset by reduced operating expenses.
- Total cash flow decreased 95% to \$26 million, primarily due to lower crude oil and natural gas sales prices and volumes as well as a lower current income tax recovery compared with the first quarter of 2015. In addition, the significant decline in oil prices also resulted in negative adjustments to cash flow totaling \$68 million in the quarter. This included write-downs on Cenovus's blended crude oil and refined product inventory as well as adjustments in its downstream business related to differences between Canadian and U.S. accounting rules.
- In the first quarter of 2016, Cenovus had capital spending of approximately \$323 million, in line with expectations, with the bulk of the spending going towards its oil sands assets. Oil sands capital investment of \$227 million was 45% lower than in the same period of 2015. Investment in conventional oil and natural gas was \$39 million, 41% lower than in the year-earlier quarter, while refining and marketing investment was \$52 million, an 18% increase.
- For the quarter, operating cash flow in excess of capital invested was \$51 million from the company's conventional oil business and \$32 million from natural gas. Capital invested in the company's refining and marketing business exceeded operating cash flow by \$75 million, while investment in its oil sands business exceeded operating cash flow by \$182 million.

- After investing approximately \$323 million during the first quarter, Cenovus had a free cash flow shortfall of \$297 million compared with a free cash flow shortfall of \$34 million in the same period a year earlier.
- Net loss was \$118 million in the first quarter compared with a loss of \$668 million in the same period of 2015. The year-over-year improvement was primarily due to non-operating unrealized foreign-exchange gains of \$413 million compared with unrealized losses of \$514 million a year ago, offset by lower commodity prices in 2016 and an asset impairment of \$170 million.
- G&A expenses were \$60 million in the quarter, 15% lower than in the same period of 2015. The decrease was primarily due to workforce reductions and lower information technology costs. Lower discretionary spending also contributed to the decrease. The company anticipates recording severance costs of \$17 million in the second quarter of 2016 related to workforce reductions that were announced in February and largely completed in April.
- At March 31, 2016, the company's net debt to capitalization ratio was 16% and net debt to adjusted EBITDA was 1.3 times. The debt to capitalization ratio was 34% and debt to adjusted EBITDA was 3.6 times. Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. The company expects these ratios may be outside of the target ranges at different points in the economic cycle.

#### **Commodity price hedging**

- Since the release of its fourth quarter earnings statement on February 11, 2016, Cenovus has added 53,000 bbls/d of WTI fixed-price contracts for the first half of 2017 at an average price of US\$45.51/bbl and established a WTI floor price of US\$43.00/bbl on 5,000 bbls/d for the second half of 2017. As of today, the company has approximately 21% of its oil production hedged for the remainder of 2016 at a volume-weighted average floor price of C\$66.10/bbl.
- In the first quarter of 2016, Cenovus had realized after-tax hedging gains of \$122 million, as the company's contract prices exceeded average benchmark prices. The company had unrealized after-tax hedging losses of \$108 million during the quarter.
- Including hedging, market access commitments and downstream integration largely provided by the company's two U.S. refineries, Cenovus has positioned itself to mitigate the impact of swings in the Canadian light-heavy oil price differential for more than 85% of its anticipated 2016 heavy oil production. Together, these mechanisms help to support Cenovus's financial resilience during this challenging period for the industry.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated April 26, 2016, should be read in conjunction with our March 31, 2016 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2015 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 26, 2016, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management 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), 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.

### Basics 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

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. 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 of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources 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 March 31, 2016, we had a market capitalization of approximately \$14 billion. We 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."). Our average crude oil and NGLs (collectively, "crude oil") production for the three months ended March 31, 2016 was 197,551 barrels per day and our average natural gas production was 408 MMcf per day. Our refineries processed an average of 435,000 gross barrels per day of crude oil feedstock into an average of 460,000 gross barrels per day of refined products.

### Our Top Priority

The low commodity price environment has continued to significantly impact the oil and gas industry. Deterioration of crude oil prices from 2015 has resulted in further declines in our cash flow and earnings. While our balance sheet remains strong, with approximately \$3.9 billion of cash on hand at March 31, 2016 and no debt maturing until the fourth quarter of 2019, we have further reduced our planned 2016 capital, operating, general and administrative spending by \$400 million to \$500 million, relative to our original budget. Maintaining our financial resilience continues to be our top priority, while maintaining safe operations.

### Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving global prices for our products. It is based on our disciplined execution, focused innovation and our financial strength. The manufacturing approach we use to produce crude oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns.

Our integrated approach positions us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for long-term growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will position us to achieve the best pricing for our oil.



We have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

### ***Oil Development***

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities.

We are positioned to increase our annual net crude oil production, including our conventional crude oil operations, by fully developing our producing projects and those that currently have regulatory approval.

### ***Disciplined Manufacturing***

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, positioning us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

### ***Financial Strength***

Maintaining a strong balance sheet is necessary to execute our strategy. We anticipate our total annual capital investment for 2016 to be between \$1.2 billion and \$1.3 billion. This is 27 percent lower than in 2015, reflecting moderate spending in response to the sustained low commodity price environment. At March 31, 2016, we had \$3.9 billion of cash on hand, \$4.0 billion of undrawn capacity on our committed credit facility, and no debt maturing until the fourth quarter of 2019. To help preserve our continued financial resilience, we will pursue further cost reductions, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

### ***Dividend***

In the first quarter, we paid a dividend of \$0.05 per share or \$41 million. This is a 69 percent reduction from our dividend of \$0.16 per share in the fourth quarter of 2015. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

### ***Focused Innovation***

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing technologies with a focus on increasing recoveries from our reservoirs, and improving cycle times, margins and environmental performance. We have a track record of developing innovative solutions that unlock challenging crude oil resources, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

## **Our Operations**

### ***Oil Sands***

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Three Months Ended March 31, 2016		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
<b>Existing Projects</b>			
Foster Creek	50	60,882	121,764
Christina Lake	50	77,093	154,186
Narrows Lake	50	-	-
<b>Emerging Projects</b>			
Telephone Lake	100	-	-
Grand Rapids	100	-	-

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions of northeastern Alberta, respectively.

(\$ millions)	<b>Three Months Ended March 31, 2016</b>	
	<b>Crude Oil</b>	<b>Natural Gas</b>
Operating Cash Flow	<b>45</b>	<b>1</b>
Capital Investment	<b>227</b>	<b>-</b>
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>(182)</b>	<b>1</b>

### **Conventional**

Crude oil production from our Conventional business segment continues to generate dependable near-term cash flows. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our 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 and provides cash flow to help fund our growth opportunities.

(\$ millions)	<b>Three Months Ended March 31, 2016</b>	
	<b>Crude Oil <sup>(1)</sup></b>	<b>Natural Gas</b>
Operating Cash Flow	<b>88</b>	<b>33</b>
Capital Investment	<b>37</b>	<b>2</b>
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>51</b>	<b>31</b>

(1) Includes NGLs.

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("CO<sub>2</sub>") enhanced oil recovery project in Weyburn, Saskatchewan, and emerging tight oil assets in Alberta.

### **Refining and Marketing**

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. The Wood River and Borger refineries have a gross crude oil capacity of approximately 314,000 barrels per day and 146,000 barrels per day, respectively.

Our 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)	<b>Three Months Ended March 31, 2016</b>
Operating Cash Flow	<b>(23)</b>
Capital Investment	<b>52</b>
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>(75)</b>

## QUARTERLY HIGHLIGHTS

Average crude oil benchmark prices continued to decline in the first quarter of 2016, decreasing between 21 and 31 percent compared with the fourth quarter of 2015, and we are undertaking additional measures to help preserve our financial resilience.

In the first quarter, we:

- Realized Operating Losses of \$423 million or \$17.38 per barrel of crude oil equivalent sold;
- Incurred a Cash Flow shortfall before realized risk management activities of \$96 million;
- Realized gains of \$6.08 per barrel of crude oil equivalent sold from upstream risk management activities;
- Decreased our total crude oil operating costs by 20 percent or \$49 million, compared with 2015;
- Identified additional workforce reductions in the first quarter, which were largely implemented in early April, which will result in an 11 percent reduction from our workforce at December 31, 2015; and
- Recorded inventory and asset impairments of \$31 million and \$170 million, respectively, due to a decline in commodity prices.

In February, we announced plans to reduce our 2016 capital, operating, general and administrative spending by \$400 million to \$500 million, relative to our original 2016 budget. Capital spending across our operations is planned to be between \$1.2 billion and \$1.3 billion, a reduction of \$200 million to \$300 million. Operating and general and administrative cost savings of \$200 million are anticipated through further prioritization of repairs and maintenance, the cancellation or deferral of non-essential work, and workforce reductions. We also reduced our dividend to \$0.05 per share in the first quarter of 2016.

## OPERATING RESULTS

Crude oil production from our Oil Sands segment and Conventional properties declined in the first quarter of 2016.

### Crude Oil Production Volumes

(barrels per day)	Three Months Ended March 31,		
	2016	Percent Change	2015
<b>Oil Sands</b>			
Foster Creek	60,882	(10)%	67,901
Christina Lake	77,093	1%	76,471
	<b>137,975</b>	<b>(4)%</b>	144,372
<b>Conventional</b>			
Heavy Oil	31,247	(16)%	37,155
Light and Medium Oil	27,121	(23)%	35,135
NGLs <sup>(1)</sup>	1,208	(11)%	1,358
	<b>59,576</b>	<b>(19)%</b>	73,648
<b>Total Crude Oil Production</b>	<b>197,551</b>	<b>(9)%</b>	218,020

(1) NGLs include condensate volumes.

At Foster Creek, our surface facilities (steam and fluid handling) continue to perform well, constrained only by lower production from the field. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which, combined with the faster declines, contributed to lower production compared with the first quarter of 2015. In addition, a higher than average number of wells were down for servicing during the quarter, which further impacted production. We increased workover activity in 2016 and have started bringing some of these wells back online.

Production from Christina Lake increased slightly compared with the first quarter of 2015 due to additional wells and reliable performance of our facilities.

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,700 barrels per day in the first quarter of 2015.

## Natural Gas Production Volumes

(MMcf per day)	Three Months Ended March 31,	
	2016	2015
Conventional	391	442
Oil Sands	17	20
	<b>408</b>	<b>462</b>

Our natural gas production declined 12 percent compared with the first quarter of 2015. Production decreased primarily due to expected natural declines, and the sale of our royalty interest and mineral fee title lands business, which produced 19 MMcf per day during the first quarter of 2015.

## Operating Netbacks

	Crude Oil <sup>(1)</sup> (\$/bbl)		Natural Gas (\$/Mcf)	
	Three Months Ended March 31,			
	2016	2015	2016	2015
Price <sup>(2)</sup>	15.97	31.08	2.31	3.05
Royalties	0.92	1.16	0.09	0.05
Transportation and Blending <sup>(2)</sup>	5.85	5.31	0.10	0.12
Operating Expenses <sup>(3)</sup>	11.08	12.89	1.23	1.26
Production and Mineral Taxes	0.11	0.22	-	0.01
<b>Netback Excluding Realized Risk Management <sup>(4)</sup></b>	<b>(1.99)</b>	<b>11.50</b>	<b>0.89</b>	<b>1.61</b>
Realized Risk Management Gain (Loss)	8.16	6.58	-	0.29
<b>Netback Including Realized Risk Management</b>	<b>6.17</b>	<b>18.08</b>	<b>0.89</b>	<b>1.90</b>

(1) Includes NGLs.

(2) The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was \$20.06 per barrel (2015 - \$22.29 per barrel).

(3) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(4) The netbacks do not reflect non-cash write-downs of product inventory.

Our average crude oil netback for the first quarter of 2016, excluding realized risk management gains and losses, was negative primarily due to lower sales prices, consistent with the decline in benchmark prices and stable heavy oil differentials. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark resulting from inventory timing in a falling price environment and transportation between market hubs and field locations.

The weakening of the Canadian dollar compared with the first quarter of 2015 had a positive impact on our crude oil price of approximately \$1.54 per barrel.

Our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the decline in the AECO benchmark price.

## Refining

Crude oil runs decreased slightly compared with 2015, although higher heavy crude oil volumes were processed due to the optimization of our total crude input slate. In the first quarter of 2016, we completed planned and unplanned maintenance at our Wood River and Borger refineries. In the first quarter of 2015, a planned turnaround was completed at our Borger Refinery.

	Three Months Ended March 31,		2015
	2016	Percent Change	
Crude Oil Runs <sup>(1)</sup> (Mbbbls/d)	435	(1)%	439
Heavy Crude Oil <sup>(1)</sup>	241	10%	220
Refined Product <sup>(1)</sup> (Mbbbls/d)	460	(2)%	469
Crude Utilization <sup>(1)</sup> (percent)	95	-	95

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

Operating Cash Flow from Refining and Marketing in the first quarter of 2016 was a shortfall of \$23 million, primarily due to lower average market crack spreads and higher operating costs, partially offset by weakening of the Canadian dollar relative to the U.S. dollar.

Further information on the changes in our production volumes, items included in our operating 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 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>

	Q1 2016	Percent Change	Q1 2015	Q4 2015
<b>Crude Oil Prices (US\$/bbl)</b>				
<b>Brent</b>				
Average	35.08	(36)%	55.17	44.71
End of Period	39.60	(28)%	55.11	37.28
<b>WTI</b>				
Average	33.45	(31)%	48.63	42.18
End of Period	38.34	(19)%	47.60	37.04
Average Differential Brent-WTI	1.63	(75)%	6.54	2.53
<b>WCS <sup>(2)</sup></b>				
Average	19.21	(43)%	33.90	27.69
End of Period	26.75	(28)%	37.30	24.98
Average Differential WTI-WCS	14.24	(3)%	14.73	14.49
<b>Condensate (C5 @ Edmonton) <sup>(3)</sup></b>				
Average	34.39	(25)%	45.62	41.67
Average Differential WTI-Condensate (Premium)/Discount	(0.94)	(131)%	3.01	0.51
Average Differential WCS-Condensate (Premium)/Discount	(15.18)	30%	(11.72)	(13.98)
<b>Average Refined Product Prices (US\$/bbl)</b>				
Chicago Regular Unleaded Gasoline ("RUL")	42.00	(33)%	62.45	55.24
Chicago Ultra-low Sulphur Diesel ("ULSD")	44.55	(37)%	70.33	59.23
<b>Refining Margin: Average 3-2-1 Crack Spreads (US\$/bbl)</b>				
Chicago	9.58	(42)%	16.53	14.47
Group 3	10.52	(40)%	17.46	13.82
<b>Average Natural Gas Prices</b>				
AECO (C\$/Mcf)	2.11	(28)%	2.95	2.65
NYMEX (US\$/Mcf)	2.09	(30)%	2.98	2.27
Basis Differential NYMEX-AECO (US\$/Mcf)	0.56	(2)%	0.57	0.27
<b>Foreign Exchange Rates (US\$ per C\$1)</b>				
Average	0.728	(10)%	0.806	0.749

(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 operating netbacks table in the Operating Results section of this MD&A.

(2) The average Canadian dollar WCS benchmark price for the first quarter of 2016 was \$26.39 per barrel (2015 – \$42.06 per barrel).

(3) The average Canadian dollar condensate benchmark price for the first quarter of 2016 was \$47.24 per barrel (2015 – \$56.60 per barrel).

### Crude Oil Benchmarks

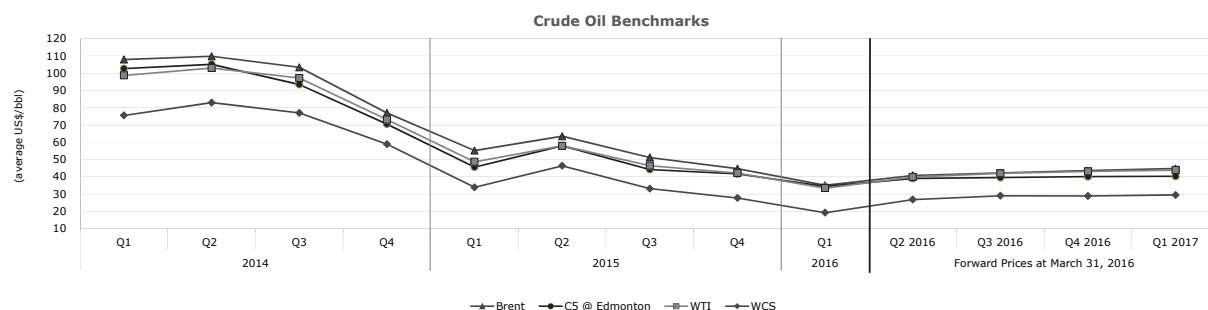
The average Brent, WTI and WCS benchmark prices continued to be impacted by the global imbalance of supply and demand which began in the second half of 2014. This imbalance, created by weak global demand for oil and strong growth in North American crude oil supply, was further amplified by the decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Some OPEC and non-OPEC members discussed the possibility of a freeze in production, although at relatively high levels. However, a formal agreement was not reached as Saudi Arabia has stated it will not freeze production without Iran's participation. The current price environment, which is slowing U.S. supply growth, is gradually improving the global oil imbalance of supply and demand. However, economic uncertainty in China, continued strong production from Saudi Arabia and Iraq, as well as concerns regarding the return of Iranian production are expected to limit near-term price increases.

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. The average Brent-WTI differential narrowed compared with the first quarter of 2015. WTI benchmark prices strengthened relative to Brent as a result of high global crude oil inventory levels, declining U.S. supply and the lifting of the U.S. export ban, leaving transportation costs as the primary driver of the Brent-WTI differential. As a result, we believe both Brent and WTI are currently indicative of inland refined product prices.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed only slightly from the first quarter of 2015, despite the steep decline in the WTI and WCS benchmark prices from the ongoing global oil imbalance of supply and demand. This imbalance has also resulted in higher global imports of medium and heavy crude into North American markets, which has in turn, further reduced WCS prices.

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.

Average condensate prices exceeded the WTI benchmark price in the first quarter of 2016 in contrast to condensate being sold at a discount to WTI in the first quarter of 2015. Strong condensate prices are attributable to higher seasonal diluent demand during winter months coupled with strong gasoline demand in North America.

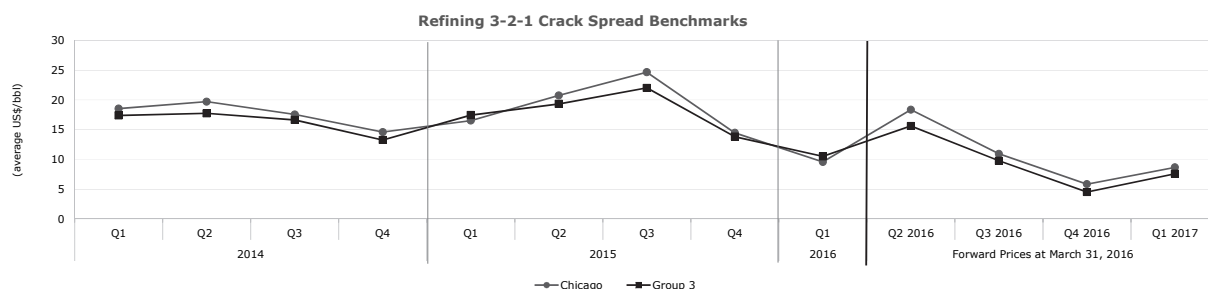


### Refining Benchmarks

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 3-2-1 crack spreads and Group 3 crack spreads decreased in the first quarter of 2016 compared with 2015 due to higher global refined product inventory and the narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil, 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 natural gas prices decreased in 2016 primarily due to increased supply from the U.S. and Canada.

### Foreign Exchange Benchmarks

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. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the first quarter of 2016, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and the expectation of higher U.S. interest rates in the future. The weakening of the Canadian dollar, compared with the first quarter of 2015, had a positive impact of approximately \$216 million on our revenues. As at March 31, 2016, the Canadian dollar was stronger relative to the U.S. dollar than as at December 31, 2015, which resulted in \$413 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

Sustained low commodity prices in the first quarter of 2016 significantly impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

(\$ millions, except per share amounts)	2016 Q1	2015				2014			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
<b>Revenues</b>	<b>2,245</b>	2,924	3,273	3,726	3,141	4,238	4,970	5,422	5,012
<b>Operating Cash Flow</b> <sup>(1)(2)</sup>	<b>144</b>	357	602	932	548	537	1,156	1,305	1,181
<b>Cash Flow</b> <sup>(1)</sup>	<b>26</b>	275	444	477	495	401	985	1,189	904
Per Share – Diluted	<b>0.03</b>	0.33	0.53	0.58	0.64	0.53	1.30	1.57	1.19
<b>Operating Earnings (Loss)</b> <sup>(1)</sup>	<b>(423)</b>	(438)	(28)	151	(88)	(590)	372	473	378
Per Share – Diluted	<b>(0.51)</b>	(0.53)	(0.03)	0.18	(0.11)	(0.78)	0.49	0.62	0.50
<b>Net Earnings (Loss)</b>	<b>(118)</b>	(641)	1,801	126	(668)	(472)	354	615	247
Per Share – Basic	<b>(0.14)</b>	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81	0.33
Per Share – Diluted	<b>(0.14)</b>	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81	0.33
<b>Capital Investment</b> <sup>(3)</sup>	<b>323</b>	428	400	357	529	786	750	686	829
<b>Dividends</b>									
Cash Dividends	<b>41</b>	132	133	125	138	201	201	201	202
In Shares from Treasury	<b>-</b>	-	-	98	84	-	-	-	-
Per Share	<b>0.05</b>	0.16	0.16	0.2662	0.2662	0.2662	0.2662	0.2662	0.2662

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

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

### Revenues

(\$ millions)

<b>Revenues for the Three Months Ended March 31, 2015</b>	<b>3,141</b>
Increase (Decrease) due to:	
Oil Sands	<b>(259)</b>
Conventional	<b>(168)</b>
Refining and Marketing	<b>(508)</b>
Corporate and Eliminations	<b>39</b>
<b>Revenues for the Three Months Ended March 31, 2016</b>	<b>2,245</b>

Combined Oil Sands and Conventional revenues declined 37 percent in the first quarter of 2016 due to lower commodity prices and reduced sales volumes, partially offset by weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues. These declines were partially offset by lower royalties.

Revenues from our Refining and Marketing segment decreased 24 percent from 2015. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by the weakening 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 in 2016 decreased 18 percent from 2015, primarily due to a decline in sales prices and purchased crude oil volumes, partially offset by an increase in purchased 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.

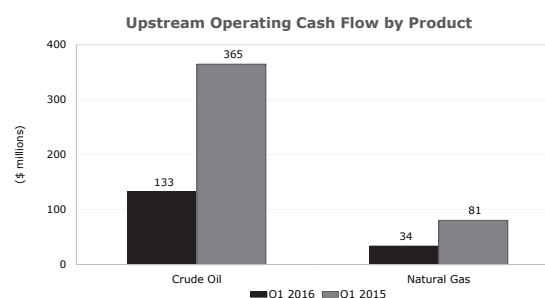
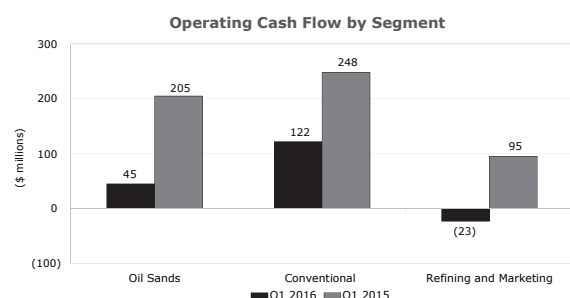
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

## Operating Cash Flow

Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and 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 Cash Flow.

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Revenues</b>	<b>2,312</b>	3,247
(Add) Deduct:		
Purchased Product	1,428	1,838
Transportation and Blending	451	528
Operating Expenses <sup>(1)</sup>	452	479
Production and Mineral Taxes	2	5
Realized (Gain) Loss on Risk Management Activities	(165)	(151)
<b>Operating Cash Flow</b>	<b>144</b>	548

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.



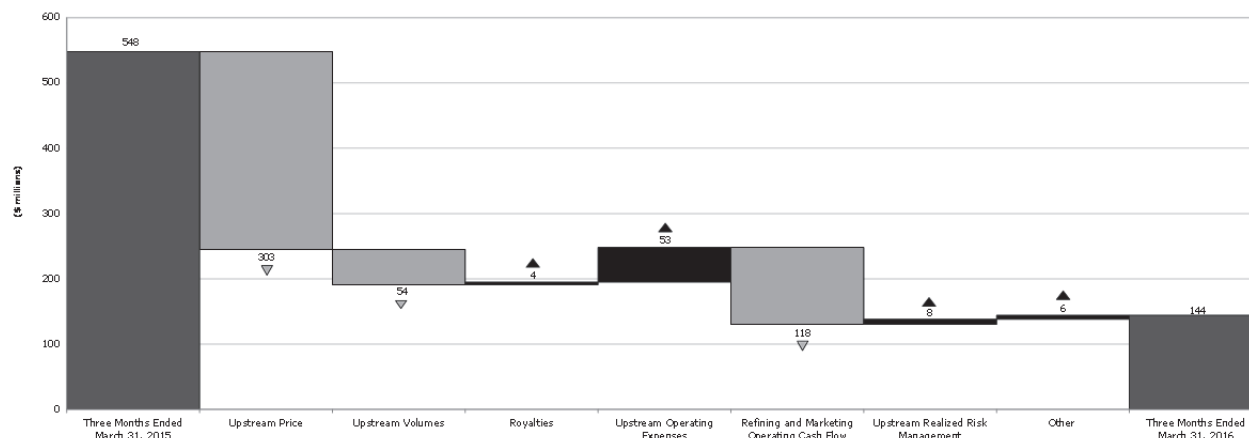
Operating Cash Flow declined 74 percent in the first quarter of 2016 primarily due to:

- A 49 percent decrease in our average crude oil sales price and a 24 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- An eight percent decline in our crude oil sales volumes as well as a 12 percent decline in natural gas sales volumes; and
- Lower Operating Cash Flow from Refining and Marketing as a result of lower average market crack spreads and higher operating costs, partially offset by weakening of the Canadian dollar relative to the U.S. dollar.

These declines in Operating Cash Flow were partially offset by:

- A \$75 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes; and
- A \$49 million decrease in crude oil operating expenses primarily due to our workforce reductions undertaken in 2015, lower chemical costs, repairs and maintenance activities, and workover activities.

## Operating Cash Flow Variance





Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

## Cash Flow

Cash 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. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Cash From Operating Activities</b>	<b>182</b>	275
(Add) Deduct:		
Net Change in Other Assets and Liabilities	(29)	(54)
Net Change in Non-Cash Working Capital	185	(166)
<b>Cash Flow</b>	<b>26</b>	495

In the first quarter of 2016, Cash Flow decreased due to a combination of lower Operating Cash Flow, as discussed above, and a lower current income tax recovery.

## 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, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Earnings (Loss), Before Income Tax</b>	<b>(335)</b>	(781)
Add (Deduct):		
Unrealized Risk Management (Gain) Loss <sup>(1)</sup>	149	145
Non-operating Unrealized Foreign Exchange (Gain) Loss <sup>(2)</sup>	(413)	514
(Gain) Loss on Divestiture of Assets	-	(16)
<b>Operating Earnings (Loss), Before Income Tax</b>	<b>(599)</b>	(138)
Income Tax Expense (Recovery)	(176)	(50)
<b>Operating Earnings (Loss)</b>	<b>(423)</b>	(88)

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

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

Operating Earnings decreased compared with the same period in 2015 primarily due to lower Cash Flow and higher depreciation, depletion and amortization ("DD&A") as a result of asset impairments, partially offset by a deferred income tax recovery.

## Net Earnings

(\$ millions)	
<b>Net Earnings (Loss) for the Three Months Ended March 31, 2015</b>	<b>(668)</b>
Increase (Decrease) due to:	
Operating Cash Flow <sup>(1) (2)</sup>	<b>(404)</b>
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	(4)
Unrealized Foreign Exchange Gain (Loss)	932
Gain (Loss) on Divestiture of Assets	(16)
Expenses <sup>(2) (3)</sup>	(18)
Depreciation, Depletion and Amortization	(43)
Exploration Expense	(1)
Income Tax Recovery	104
<b>Net Earnings (Loss) for the Three Months Ended March 31, 2016</b>	<b>(118)</b>

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

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

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

In 2016, our Net Earnings increased primarily due to non-operating unrealized foreign exchange gains of \$413 million (2015 – unrealized losses of \$514 million), partially offset by a decline in Operating Earnings, as discussed above.

## Net Capital Investment

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Oil Sands	227	414
Conventional	39	66
Refining and Marketing	52	44
Corporate and Eliminations	5	5
<b>Capital Investment</b>	<b>323</b>	529
Divestitures	-	(16)
<b>Net Capital Investment <sup>(1)</sup></b>	<b>323</b>	513

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

Capital investment in the first quarter of 2016 declined 39 percent as we reduced our spending in light of the low commodity price environment.

Oil Sands capital investment focused primarily on sustaining capital related to existing production, the phase G expansion at Foster Creek, and the Christina Lake expansion phase F. We drilled 192 gross stratigraphic test wells at Foster Creek and Christina Lake to determine pad placement for sustaining wells and near-term expansion phases. Conventional capital investment focused on maintenance capital and spending for our CO<sub>2</sub> enhanced oil recovery project at Weyburn.

Capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives.

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

## Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to capital for our existing business operations;
- Second, to paying a 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 within the context of achieving our objectives 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 flow. 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 March 31,	
	2016	2015
Cash Flow <sup>(1)</sup>	26	495
Capital Investment (Committed and Growth)	323	529
Free Cash Flow <sup>(2)</sup>	(297)	(34)
Cash Dividends	41	138
	<b>(338)</b>	(172)

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

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

We expect our capital investment for 2016 to be funded from internally generated cash flow and our cash balance on hand.

## REPORTABLE SEGMENTS

Our reportable segments are as follows:

**Oil Sands**, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of Cenovus's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

**Conventional**, which 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.

**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 operating 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

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Oil Sands	470	729
Conventional	254	422
Refining and Marketing	1,588	2,096
Corporate and Eliminations	(67)	(106)
	<b>2,245</b>	<b>3,141</b>

### OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of development, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. 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 include:

- Negative crude oil netbacks, excluding realized risk management activities, of \$6.10 per barrel;
- Production at Foster Creek decreasing 10 percent to an average of 60,882 barrels per day as strong facility performance was offset by lower field production;
- Reducing our crude oil operating costs by \$17 million or \$1.47 per barrel; and
- Reducing capital investment by \$187 million compared with 2015.

## Oil Sands – Crude Oil

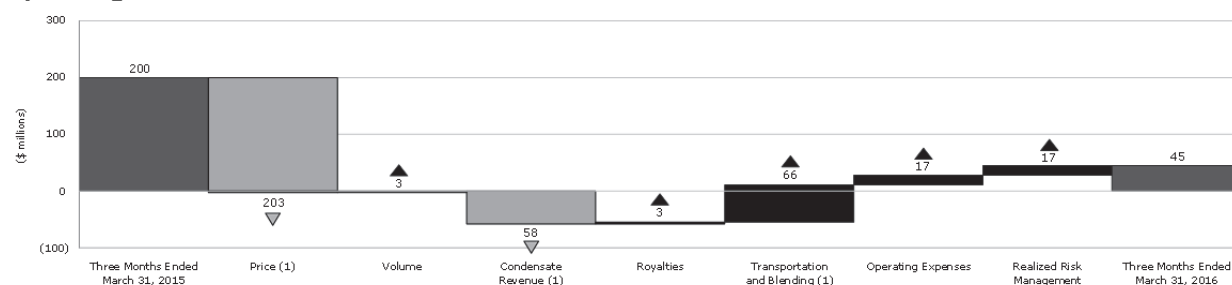
### Financial Results

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Gross Sales</b>	<b>465</b>	723
Less: Royalties	-	3
<b>Revenues</b>	<b>465</b>	720
<b>Expenses</b>		
Transportation and Blending	404	470
Operating <sup>(1)</sup>	122	139
(Gain) Loss on Risk Management	(106)	(89)
<b>Operating Cash Flow</b>	<b>45</b>	200
Capital Investment	227	413
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>(182)</b>	(213)

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

### Operating Cash Flow 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

#### Pricing

In the first quarter, our average crude oil sales price was \$10.13 per barrel, a 61 percent decrease from 2015. The decline in our crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark resulting from inventory timing in a falling price environment and transportation between market hubs and field locations. Weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market, which generally secure a higher sales price, positively impacted our realized sales prices.

The WCS-CDB differential narrowed by 39 percent to a discount of US\$1.96 per barrel (2015 – US\$3.21 per barrel). In the first quarter, 90 percent of our Christina Lake production was sold as CDB (2015 – 86 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

#### Production Volumes

	Three Months Ended March 31,	
(barrels per day)	2016	Percent Change
Foster Creek	60,882	(10)%
Christina Lake	77,093	1%
	<b>137,975</b>	<b>(4)%</b>
		2015
		67,901
		76,471
		144,372

At Foster Creek, our surface facilities (steam and fluid handling) continue to perform well constrained only by lower production from the field. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which, combined with the faster declines, contributed to lower production compared with the first quarter of 2015. In addition, a higher than average number of wells were down for servicing during the quarter, which further

impacted production. We increased workover activity in 2016 and have started bringing some of these wells back online.

Production from Christina Lake increased slightly compared with the first quarter of 2015 due to additional wells and consistent performance of our facilities.

#### *Condensate*

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

#### *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 realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs.

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

#### *Effective Royalty Rates*

(percent)	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
Foster Creek	<b>(4.9)</b>	(1.2)
Christina Lake	<b>1.2</b>	3.1

Royalties decreased primarily due to the decline in crude oil sales prices. At Foster Creek, low crude oil sales prices and the true-up of the 2015 royalty calculation resulted in a negative royalty rate for the first quarter of 2016. In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation for Foster Creek. We recorded the associated credit in the first quarter of 2015, which resulted in a negative royalty rate. Excluding the credit, the effective royalty rate for Foster Creek would have been 5.9 percent in the first quarter of 2015.

The Christina Lake royalty rate decreased in the first quarter as a result of lower sales prices.

#### **Expenses**

##### *Transportation and Blending*

Transportation and blending costs decreased \$66 million or 14 percent. Blending costs declined primarily as a result of lower condensate prices partially offset by higher condensate volumes from increased production at Christina Lake. Our condensate costs were higher than the average benchmark price in the first quarter, primarily due to the utilization of higher priced inventory and the transportation expense associated with moving the condensate to our oil sands projects. In the first quarter of 2016, we recorded a \$25 million, or \$2.00 per barrel of oil sold, (2015 – \$nil) write-down of our blended crude oil inventory to net realizable value as a result of the decline in crude oil prices through March and into April.

Transportation costs increased primarily due to higher pipeline tariffs and higher tariffs from additional sales to the U.S. market, which generally secure higher sales prices, partially offset by lower rail costs. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Lower volumes were moved by rail in the first quarter of 2016. We transported an average of 4,627 gross barrels per day of crude oil by rail, consisting of seven unit train shipments (2015 – 11,871 gross barrels per day, 18 unit train shipments). The seven unit trains were loaded at our crude-by-rail terminal operations, located in Bruderheim, Alberta.

## Operating

Primary drivers of our operating expenses for the first quarter were workforce, fuel, workovers, repairs and maintenance and chemical costs. Total operating expenses decreased \$17 million or \$1.47 per barrel primarily as a result of workforce reductions, lower natural gas prices that reduced fuel costs and lower repairs and maintenance activities.

### Per-unit Operating Expenses

(\$/bbl)	Three Months Ended March 31,		2015
	2016	Percent Change	
<b>Foster Creek</b>			
Fuel	2.48	(16)%	2.96
Non-fuel <sup>(1)</sup>	9.57	(17)%	11.54
Total	12.05	(17)%	14.50
<b>Christina Lake</b>			
Fuel	1.96	(11)%	2.19
Non-fuel <sup>(1)</sup>	5.65	(7)%	6.05
Total	7.61	(8)%	8.24
<b>Total</b>	<b>9.52</b>	<b>(13)%</b>	<b>10.99</b>

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

At Foster Creek, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:

- Lower workforce costs due to our more moderate approach to oil sands expansions;
- Lower repairs and maintenance costs due to a focus on critical operational activities; and
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes.

The decreases to non-fuel operating costs at Foster Creek were partially offset by lower production volumes.

At Christina Lake, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:

- Increased production;
- Lower workforce costs due to our more moderate approach to oil sands expansions; and
- Lower chemical costs due to supply chain initiatives.

These decreases to non-fuel operating costs at Christina Lake were partially offset by higher well workover activities related to additional pump changes.

## Operating Netbacks

(\$/bbl)	Foster Creek		Christina Lake	
	2016	2015	2016	2015
Price <sup>(1)</sup>	11.82	29.42	8.85	23.30
Royalties	(0.16)	(0.25)	0.05	0.61
Transportation and Blending <sup>(1)</sup>	8.70	9.39	5.28	4.17
Operating Expenses <sup>(2)</sup>	12.05	14.50	7.61	8.24
<b>Netback Excluding Realized Risk Management <sup>(3)</sup></b>	<b>(8.77)</b>	5.78	<b>(4.09)</b>	10.28
Realized Risk Management	9.49	8.41	7.43	6.04
<b>Netback Including Realized Risk Management</b>	<b>0.72</b>	14.19	<b>3.34</b>	16.32

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the first quarter was \$26.13 per barrel (2015 – \$30.57 per barrel) for Foster Creek, and \$26.45 per barrel (2015 – \$31.60 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) The netbacks do not reflect non-cash write-downs of product inventory.

## Risk Management

Risk management activities in the first quarter of 2016 resulted in realized gains of \$106 million (2015 – \$89 million), consistent with our contract prices exceeding average benchmark 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 first quarter of 2016, net of internal usage, was 17 MMcf per day (2015 – 20 MMcf per day). Operating Cash Flow was \$1 million (2015 – \$3 million), declining primarily due to lower natural gas sales prices.

## Oil Sands – Capital Investment

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Foster Creek	89	149
Christina Lake	114	207
	203	356
Narrows Lake	4	20
Telephone Lake	7	11
Grand Rapids	5	14
Other <sup>(1)</sup>	8	13
<b>Capital Investment <sup>(2)</sup></b>	<b>227</b>	<b>414</b>

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

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

In the first quarter, capital investment exceeded Operating Cash Flow by \$182 million (2015 – \$209 million) and was funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

### Existing Projects

Capital investment at Foster Creek focused on sustaining capital related to existing production, expansion phase G and drilling stratigraphic test wells to help identify well pad locations for sustaining wells and near-term expansion phases. Capital investment declined in the current quarter primarily due to spending reductions in response to the low commodity price environment.

Christina Lake capital investment focused on sustaining capital related to existing production, expansion phase F and drilling stratigraphic test wells to help identify well pad locations for sustaining wells and near-term expansion phases. Capital investment decreased due to the completion of the optimization project in 2015 and overall spending reductions.

Capital investment at Narrows Lake focused on detailed engineering. Capital investment declined in 2016 compared with 2015 due to the suspension of construction at Narrows Lake.

### Emerging Projects

In the first quarter of 2016, Telephone Lake capital investment declined in response to the current low commodity price environment. In the first quarter of 2015, Telephone Lake capital investment focused on front-end engineering work for the central processing facility.

Capital investment at Grand Rapids decreased as spending was limited to the wind down of the SAGD pilot. In the first quarter of 2015, a third pilot well pair was drilled at Grand Rapids.

### Drilling Activity <sup>(1)</sup>

Three Months Ended March 31,	Gross Stratigraphic Test Wells <sup>(2)</sup>		Gross Production Wells <sup>(3)</sup>	
	2016	2015	2016	2015
Foster Creek	95	122	4	13
Christina Lake	97	36	18	19
	192	158	22	32
Grand Rapids	-	-	-	1
Other	5	-	-	-
	197	158	22	33

(1) We did not drill any gross service wells in the first quarter of 2016 (2015 – five gross service wells).

(2) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the first quarter, no wells were drilled using our SkyStrat™ drilling rig (2015 – seven wells).

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

### Future Capital Investment

We have adopted a more moderate and staged approach to future oil sands expansions due the low commodity price environment. Expanding existing projects and developing emerging projects will depend upon achieving further cost reductions as well as additional federal fiscal and regulatory certainty.

### Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2016 is forecast to be between \$325 million and \$350 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Spending related to construction work on phase H was deferred in response to the low

commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between \$350 million and \$375 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Construction work on phase G was deferred in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake in 2016 is forecast to be between \$10 million and \$20 million, focusing on phase A detailed engineering.

### Emerging Projects

Capital investment for our new resource plays is forecast to be between \$45 million and \$55 million in 2016.

### Depreciation, Depletion & Amortization

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 upstream assets could be determined using the reported consolidated data:

(\$ millions, unless otherwise indicated)	As at December 31, 2015
Upstream Property, Plant and Equipment	12,627
Estimated Future Development Capital	19,671
Total Estimated Upstream Cost Base	32,298
Total Proved Reserves (MMBOE)	2,546
<b>Implied Depletion Rate (\$/BOE)</b>	<b>12.69</b>

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between \$13.50 to \$14.50 per BOE. Amounts related to assets under construction, 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 Consolidated Financial Statements.

In the first quarter of 2016, Oil Sands DD&A decreased \$22 million primarily due to a combination of lower sales volumes and lower DD&A rates. The average depletion rate was approximately \$11.55 per barrel compared with \$11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake.

### CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO<sub>2</sub> enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood technology and emerging tight oil assets in Alberta. The established assets in this segment are strategically important for their long-life reserves, stable operations and diversity of crude oil produced. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while our 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.

Significant developments that impacted our Conventional segment in the first quarter of 2016 compared with 2015 include:

- Crude oil and natural gas netbacks, excluding realized risk management activities, of \$7.73 per barrel and \$0.92 per Mcf, respectively;
- Crude oil production averaging 59,576 barrels per day, decreasing 19 percent, as an increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business;
- Reducing our crude oil operating costs by \$32 million or \$1.62 per barrel;
- Generating Operating Cash Flow net of capital investment of \$83 million, a decrease of 54 percent; and
- Recording impairment losses associated with our Northern Alberta cash generating unit ("CGU") of \$170 million due to the decline in forward commodity prices.



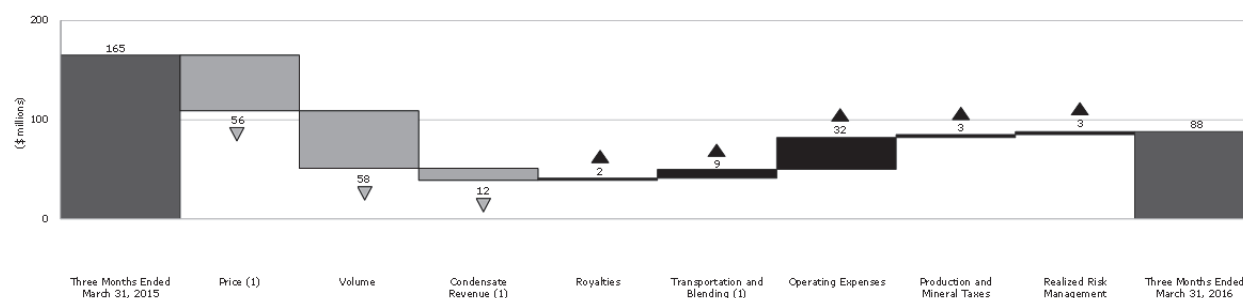
## Conventional – Crude Oil

### Financial Results

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Gross Sales</b>	<b>189</b>	315
Less: Royalties	<b>17</b>	19
<b>Revenues</b>	<b>172</b>	296
<b>Expenses</b>		
Transportation and Blending	<b>44</b>	53
Operating <sup>(1)</sup>	<b>78</b>	110
Production and Mineral Taxes	<b>2</b>	5
(Gain) Loss on Risk Management	<b>(40)</b>	(37)
<b>Operating Cash Flow</b>	<b>88</b>	165
Capital Investment	<b>37</b>	62
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>51</b>	103

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

### Operating Cash Flow 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

#### Pricing

Our average crude oil sales price decreased 26 percent to \$29.82 per barrel, consistent with the decline in crude oil benchmark prices.

#### Production Volumes

	Three Months Ended March 31,	
(barrels per day)	2016	Percent Change
Heavy Oil	<b>31,247</b>	<b>(16)%</b>
Light and Medium Oil	<b>27,121</b>	<b>(23)%</b>
NGLs	<b>1,208</b>	<b>(11)%</b>
	<b>59,576</b>	<b>(19)%</b>

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,700 barrels per day in the first quarter of 2015.

#### Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential, the proportion of the cost of condensate recovered decreased.

#### Royalties

Royalties decreased primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. For 2016, the effective crude oil royalty rate for our Conventional properties was 12.6 percent (2015 – 7.5 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 realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. The Pelican Lake royalty calculation is based on net profits.

In the first quarter of 2016, production and mineral taxes decreased consistent with the decline in crude oil prices and due to the sale of our royalty interest and mineral fee title lands business in 2015.

## Expenses

### Transportation and Blending

Transportation and blending costs decreased \$9 million. Blending costs declined due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production. In the first quarter, we recorded a \$3 million (2015 – \$3 million) write-down of our blended crude oil inventory to net realizable value as a result of the decline in crude oil prices through March and into April.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in the volumes moved by rail. We did not transport any volumes by rail in the first quarter of 2016 (2015 – 1,591 barrels per day).

### Operating

Primary drivers of our operating expenses in the first quarter of 2016 were workforce, electricity, workovers, property taxes and lease costs. Operating expenses declined \$32 million or \$1.62 per barrel.

The per-unit decline was primarily due to:

- Workforce reductions;
- Lower chemical costs associated with reduced polymer consumption; and
- A decline in repairs and maintenance and workover costs as a result of focusing on critical activities and achieving operational efficiencies.

These decreases were partially offset by lower production volumes.

## Operating Netbacks

	Heavy Oil		Light and Medium	
	Three Months Ended March 31,			
(\$/bbl)	2016	2015	2016	2015
Price <sup>(1)</sup>	25.99	35.85	34.36	45.81
Royalties	1.40	2.34	5.18	3.56
Transportation and Blending <sup>(1)</sup>	4.77	3.42	2.73	2.88
Operating Expenses <sup>(2)</sup>	13.98	17.30	16.34	16.04
Production and Mineral Taxes	-	0.02	0.82	1.28
Netback Excluding Realized Risk Management <sup>(3)</sup>	5.84	12.77	9.29	22.05
Realized Risk Management	7.98	5.58	7.90	5.90
Netback Including Realized Risk Management	13.82	18.35	17.19	27.95

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was \$10.04 per barrel (2015 – \$11.50). Our blending ratios range from approximately 10 percent to 16 percent.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) The netbacks do not reflect non-cash write-downs of product inventory.

### Risk Management

Risk management activities for the first quarter resulted in realized gains of \$40 million (2015 – \$37 million), consistent with our contract prices exceeding average benchmark prices.

## Conventional – Natural Gas

### Financial Results

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Gross Sales</b>	<b>82</b>	122
Less: Royalties	<b>3</b>	2
<b>Revenues</b>	<b>79</b>	120
<b>Expenses</b>		
Transportation and Blending	<b>3</b>	5
Operating	<b>42</b>	47
Production and Mineral Taxes	-	-
(Gain) Loss on Risk Management	<b>1</b>	(10)
<b>Operating Cash Flow</b>	<b>33</b>	78
Capital Investment	<b>2</b>	4
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>31</b>	74

Operating Cash Flow from natural gas continued to help fund our Oil Sands segment.

### Revenues

#### Pricing

In the first quarter of 2016, our average natural gas sales price decreased 25 percent to \$2.31 per Mcf, consistent with the decline in the AECO benchmark price.

#### Production

Production decreased 12 percent to 391 MMcf per day due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 19 MMcf per day in the first quarter of 2015.

#### Royalties

Royalties increased as a result of additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business, partially offset by lower prices and production declines. The average royalty rate in the first quarter was 4.5 percent (2015 – 1.7 percent).

### Expenses

#### Transportation

In 2016, transportation costs decreased as a result of lower production volumes.

#### Operating

Primary drivers of our operating expenses were property taxes and lease costs, and workforce. In the first quarter, operating expenses decreased by \$5 million primarily due to lower workforce costs, and repairs and maintenance, offset by lower production volumes.

#### Risk Management

Risk management activities resulted in realized losses of \$1 million in the first quarter of 2016 (2015 – gains of \$10 million), consistent with average benchmark prices exceeding our contract prices.

### Conventional – Capital Investment

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Heavy Oil	<b>10</b>	22
Light and Medium Oil	<b>27</b>	40
Natural Gas	<b>2</b>	4
<b>Capital Investment <sup>(1)</sup></b>	<b>39</b>	66

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

Capital investment in 2016 was primarily related to maintenance capital and spending for our CO<sub>2</sub> enhanced oil recovery project at Weyburn. Capital investment declined in the current quarter primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

## Drilling Activity

(net wells, unless otherwise stated)	Three Months Ended March 31,	
	2016	2015
Crude Oil	1	5
Recompletions	65	34
Gross Stratigraphic Test Wells	4	-

Drilling activity in the first quarter of 2016 focused on natural gas recompletions performed to optimize production.

## Future Capital Investment

We are taking a more moderate approach to developing our conventional crude oil opportunities due to the low commodity price environment. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2016 crude oil capital investment forecast is between \$125 million and \$150 million with spending plans mainly focused on maintaining and optimizing current production volumes.

## 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.

Conventional DD&A increased \$60 million in the first quarter of 2016 as the decline in sales volumes and lower DD&A rates were more than offset by impairment charges. The average depletion rate decreased approximately 20 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined, in part, from an impairment charge of \$184 million associated with our Northern Alberta CGU recorded at December 31, 2015 and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

We recorded impairment charges associated with our Northern Alberta CGU of \$170 million due to the decline in forward commodity prices.

## REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. 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 our refineries.

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

	Three Months Ended March 31,	
	2016	2015
<b>Crude Oil Capacity</b> <sup>(2)</sup> (Mbbbls/d)	460	460
<b>Crude Oil Runs</b> (Mbbbls/d)	435	439
Heavy Crude Oil	241	220
Light/Medium	194	219
<b>Refined Products</b> (Mbbbls/d)	460	469
Gasoline	229	236
Distillate	142	144
Other	89	89
<b>Crude Utilization</b> (percent)	95	95

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

(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30-day period.

On a 100-percent basis, our refineries have total capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows us to economically integrate our heavy crude oil production. Processing less expensive crude oil 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 being optimized at each refinery to maximize economic benefit. Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity.

Crude oil runs decreased slightly compared with 2015. Higher heavy crude oil volumes were processed due to the optimization of our total crude input slate, which reduces our feedstock costs. Refined product output decreased

slightly as we completed planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first quarter of 2015, a planned turnaround was completed at our Borger Refinery.

## Financial Results

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Revenues	<b>1,588</b>	2,096
Purchased Product	<b>1,428</b>	1,838
<b>Gross Margin</b>	<b>160</b>	258
<b>Expenses</b>		
Operating	<b>203</b>	177
(Gain) Loss on Risk Management	<b>(20)</b>	(14)
<b>Operating Cash Flow</b>	<b>(23)</b>	95
Capital Investment	<b>52</b>	44
<b>Operating Cash Flow Net of Related Capital Investment</b>	<b>(75)</b>	51

### Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil, 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 our refineries; and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the first quarter of 2016, the decline in gross margin was primarily due to:

- Lower average market crack spreads, which decreased by approximately 41 percent, due to higher global refined product inventory and narrowing of the Brent-WTI differential; and
- An inventory write-down of \$3 million related to our refined product inventory (2015 – \$nil million).

The decrease in gross margin was partially offset by improved margins on the sale of our secondary products, such as coke, asphalt and sulfur, due to lower overall feedstock costs consistent with the decline in WTI, and weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar relative to the U.S. dollar in the first quarter of 2016, compared with 2015, had a positive impact of approximately \$13 million on our refining gross margin.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers (“RINs”). In the first quarter of 2016, the cost of our RINs was \$62 million (2015 – \$53 million). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2016 decreased 18 percent from 2015, primarily due to a decline in sales prices, partially offset by an increase in purchased natural gas volumes.

### Operating Expense

Primary drivers of operating expenses in the first quarter of 2016 were labour, maintenance, utilities and supplies. Reported operating expenses increased compared with 2015 primarily due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by a decline in utility costs resulting from lower natural gas prices and no turnaround costs incurred in 2016.

### Refining and Marketing – Capital Investment

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Wood River Refinery	<b>36</b>	27
Borger Refinery	<b>14</b>	17
Marketing	<b>2</b>	-
	<b>52</b>	44

Capital expenditures in the first quarter of 2016 focused on the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives. Start-up of the Wood River debottlenecking project is anticipated in the third quarter of 2016.

In 2016, we expect to invest between \$240 million and \$290 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

### 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 \$9 million in 2016, 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, and the unrealized mark-to-market gains and losses on the long-term power purchase contract and interest rate swaps. In the first quarter of 2016, our risk management activities resulted in \$149 million of unrealized losses (2015 – \$145 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

(\$ millions)	Three Months Ended March 31,	
	2016	2015
General and Administrative <sup>(1)</sup>	60	71
Finance Costs	124	121
Interest Income	(11)	(11)
Foreign Exchange (Gain) Loss, Net	(403)	515
Research Costs	18	7
(Gain) Loss on Divestiture of Assets	-	(16)
	<b>(212)</b>	<b>687</b>

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

### Expenses

#### General and Administrative

Primary drivers of our general and administrative expenses in 2016 were workforce, office rent and information technology costs. General and administrative expenses decreased by \$11 million primarily due to 2015 workforce reductions and lower information technology costs. Lower discretionary spending also contributed to the reduction of general and administrative costs.

We identified additional workforce reductions in the first quarter, which were largely implemented in early April. As a result, severance costs of approximately \$17 million are expected to be recorded in the second quarter of 2016.

#### Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased \$3 million in 2016 compared with the same period in 2015 as weakening of the Canadian dollar relative to the U.S. dollar increased interest incurred on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the first quarter was 5.3 percent (2015 – 5.2 percent).

#### Foreign Exchange

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Unrealized Foreign Exchange (Gain) Loss	(409)	523
Realized Foreign Exchange (Gain) Loss	6	(8)
	<b>(403)</b>	<b>515</b>

The majority of unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was seven percent stronger at March 31, 2016 compared with December 31, 2015, resulting in unrealized gains of \$409 million.

### 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 2016 was \$17 million (2015 – \$21 million).

### Income Tax

(\$ millions)	Three Months Ended March 31,	
	2016	2015
Current Tax		
Canada	(27)	(86)
United States	-	-
<b>Total Current Tax Expense (Recovery)</b>	<b>(27)</b>	<b>(86)</b>
<b>Deferred Tax Expense (Recovery)</b>	<b>(190)</b>	<b>(27)</b>
	<b>(217)</b>	<b>(113)</b>

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

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Earnings Before Income Tax</b>	<b>(335)</b>	(781)
Canadian Statutory Rate	<b>27.0%</b>	25.2%
<b>Expected Income Tax</b>	<b>(90)</b>	(197)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	<b>(27)</b>	(11)
Non-Deductible Stock-Based Compensation	<b>2</b>	5
Non-Taxable Capital Losses	<b>(56)</b>	65
Unrecognized Capital Losses Arising From Unrealized Foreign Exchange	<b>(56)</b>	65
Adjustments Arising From Prior Year Tax Filings	<b>-</b>	(11)
Other	<b>10</b>	(29)
<b>Total Tax</b>	<b>(217)</b>	(113)
<b>Effective Tax Rate</b>	<b>64.8%</b>	14.5%

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 first quarter of 2016, we incurred losses, a portion of which will be carried back to recover taxes previously paid in Canada. In the first quarter of 2015, the current tax recovery included the results of certain corporate restructuring transactions and a favorable adjustment related to prior years. The deferred tax recovery increased in the first quarter of 2016 as the benefit from a portion of current period losses was deferred to future periods.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Our effective tax rate differs from the statutory rate due to approximately \$400 million of non-taxable foreign exchange gains.

## LIQUIDITY AND CAPITAL RESOURCES

(\$ millions)	Three Months Ended March 31,	
	2016	2015
<b>Net Cash From (Used In)</b>		
Operating Activities	<b>182</b>	275
Investing Activities	<b>(369)</b>	(643)
<b>Net Cash Provided (Used) Before Financing Activities</b>	<b>(187)</b>	(368)
Financing Activities	<b>(41)</b>	1,292
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	<b>6</b>	(3)
<b>Increase (Decrease) in Cash and Cash Equivalents</b>	<b>(222)</b>	921
	<b>March 31,</b>	December 31,
	<b>2016</b>	<b>2015</b>
<b>Cash and Cash Equivalents</b>	<b>3,883</b>	4,105
<b>Committed and Undrawn Credit Facilities</b>	<b>4,000</b>	4,000

### Operating Activities

Cash from operating activities decreased in the first quarter of 2016 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was \$4,031 million at March 31, 2016 compared with \$4,337 million at December 31, 2015.

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

## Investing Activities

Capital investment declined in the current quarter primarily due to spending reductions in response to the low commodity price environment.

## Financing Activities

Cash provided by financing activities decreased. In 2016, we paid dividends of \$0.05 per share or \$41 million. In the first quarter of 2015, cash from financing activities included net proceeds of \$1.4 billion from our common share issuance, partially offset by dividend payments of \$138 million.

Our long-term debt at March 31, 2016 was \$6,113 million (December 31, 2015 – \$6,525 million) with no principal payments due until October 2019 (US\$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The \$412 million decrease in long-term debt is due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at March 31, 2016, we were in compliance with all of the terms of our debt agreements.

## Available Sources of Liquidity

We expect cash flow from our crude oil, 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.

The following sources of liquidity are available at March 31, 2016:

(\$ millions)	Amount	Term
Cash and Cash Equivalents	3,883	Not applicable
Committed Credit Facility <sup>(1)</sup>	1,000	November 2017
Committed Credit Facility	3,000	November 2019
U.S. Base Shelf Prospectus <sup>(2)</sup>	US\$5,000	March 2018
Canadian Base Debt Shelf Prospectus <sup>(2)</sup>	1,500	July 2016

(1) Extended to April 30, 2019, effective April 22, 2016.

(2) Availability is subject to market conditions.

## Committed Credit Facility

We have a \$4.0 billion committed credit facility, with \$1.0 billion maturing on April 30, 2019 and \$3.0 billion maturing on November 30, 2019. Effective April 22, 2016, we extended the maturity date of the \$1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at March 31, 2016, no amounts are drawn on our committed credit facilities.

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

## U.S. and Canadian Base Shelf Prospectuses

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows us to offer, from time to time, up to US\$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018 and replaces the US\$2.0 billion U.S. base debt shelf prospectus. In addition, we have a \$1.5 billion Canadian base debt shelf prospectus, which will expire in July 2016.

As at March 31, 2016, there have been no issuances under either of the prospectuses.

## Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics 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 earnings before finance costs, interest income, income tax expense, DD&A, goodwill and asset impairments, 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. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	March 31, 2016	December 31, 2015
Net Debt to Capitalization <sup>(1) (2)</sup>	16%	16%
Debt to Capitalization	34%	34%
Net Debt to Adjusted EBITDA <sup>(1)</sup>	1.3x	1.2x
Debt to Adjusted EBITDA	3.6x	3.1x

(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.



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.

Debt to Capitalization remained consistent as the lower long-term debt balance, from the strengthening of the Canadian dollar relative to the U.S. dollar, was offset by the decrease in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of lower Adjusted EBITDA, primarily due to a decline in Cash Flow from lower commodity prices, partially offset by the lower long-term debt balance.

Additional information regarding our financial metrics and capital structure can be found in the notes to the 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 Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 16 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at March 31, 2016	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	833,290	N/A
Stock Options	43,811	34,141
Other Stock-Based Compensation Plans	8,043	1,566

### Contractual Obligations and Commitments

We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements and operating leases on buildings. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

During the first quarter of 2016, net transportation commitments decreased by approximately \$1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms 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 March 31, 2016, total transportation commitments were \$26 billion.

As at March 31, 2016, there were outstanding letters of credit aggregating \$211 million issued as security for performance under certain contracts (December 31, 2015 – \$64 million).

### Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

## RISK MANAGEMENT

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 2015 annual MD&A. A description of the risk factors and uncertainties affecting Cenovus 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, 2015.

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 2015 annual MD&A.

The following provides an update on our risks related to commodity prices, royalty regimes and climate change.

### Commodity Price Risk

Fluctuations in commodity prices and refined product prices impacts 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 18 and 19 to the interim Consolidated Financial Statements.

## Impact of Financial Risk Management Activities

(\$ millions)	Three Months Ended March 31,			2015		
	2016			2015		
	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	(164)	118	(46)	(128)	119	(9)
Natural Gas	-	-	-	(12)	11	(1)
Refining	(4)	3	(1)	(14)	9	(5)
Power	3	(14)	(11)	3	6	9
Interest Rate	-	42	42	-	-	-
<b>(Gain) Loss on Risk Management</b>	<b>(165)</b>	<b>149</b>	<b>(16)</b>	<b>(151)</b>	<b>145</b>	<b>(6)</b>
Income Tax Expense (Recovery)	43	(41)	2	40	(37)	3
<b>(Gain) Loss on Risk Management, After Tax</b>	<b>(122)</b>	<b>108</b>	<b>(14)</b>	<b>(111)</b>	<b>108</b>	<b>(3)</b>

In the first quarter of 2016, we recorded realized gains on crude oil risk management activities, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil financial instruments primarily due to the realization of settled positions and changes in market prices. Unrealized losses were recorded on our interest rate hedge positions due to decreases in benchmark interest rates.

### 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 price increases. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

### Royalty Regime Risk

The Governments of Alberta and Saskatchewan receive royalties on the production of crude oil and natural gas from lands where they own the mineral rights. The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 (the "Review"). The Review recommends no changes to the existing oil sands royalty structure. It also calls for a modernization of Alberta's conventional oil and gas royalty regime and the Government of Alberta is currently consulting with industry to finalize details of the royalty calculations. The Review further recommends that all wells drilled before 2017 be grandfathered under the current rules for a 10 year period. The Government of Alberta has accepted the recommendations and is expected to adopt them in the spring of 2016, to take effect in 2017.

These changes to the Alberta provincial royalty structure are not anticipated to materially impact Cenovus's financial condition; however, any future changes to the royalty and mineral tax regimes in provinces in which we operate, could have a significant impact on Cenovus's financial condition, results of operations, cash flows, and future capital expenditures.

### Climate Change Risk

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas emissions ("GHG") and other air pollutants. In November, 2015, the Government of Alberta announced its climate leadership plan (the "CLP") highlighting four key strategies that will be implemented to address climate change. Legislation to implement the CLP is anticipated to be brought forward in the spring of 2016, to take effect in 2017.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of GHG emitting facilities. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12 percent to 15 percent in 2016 and 20 percent in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The SGER amendments increased the price for such credits from \$15 per tonne to \$20 per tonne for 2016 and \$30 per tonne in 2017.

In December 2015, Canada and other countries that are members of the United Nations Framework Convention on Climate Change signed the Paris Agreement on climate change, which aims to limit the rate of global warming and contemplates developing carbon markets by 2020. The Government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016. We are unable to predict the impact of the Paris Agreement on our operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on our financial condition, results of operations, and cash flow.

If comprehensive GHG regulation is enacted in Alberta or any jurisdiction in which we operate, including in relation to the CLP, the Paris Agreement, or the amendments to the SGER, we may incur increased compliance costs or actions, loss of markets, permitting delays, and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil, natural gas and certain refined products. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

## **CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES 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 Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

### **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 three months ended March 31, 2016. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

### **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.

### **Changes in Accounting Policies**

There were no new or amended accounting standards or interpretations adopted during the three months ended March 31, 2016.

### **Future Accounting Pronouncements**

A description of additional accounting standards and interpretations that will be adopted in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

## **CONTROL ENVIRONMENT**

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There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

## OUTLOOK

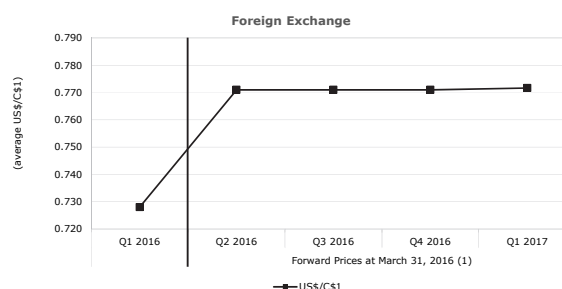
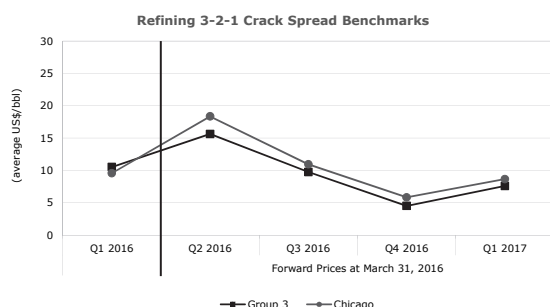
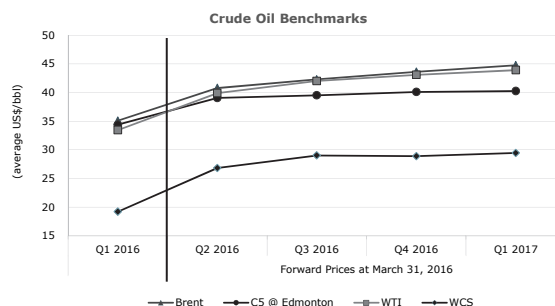
We expect 2016 will be a very challenging year for our industry and our business. Maintaining our financial resilience remains our top priority, while maintaining safe operations. Our 2016 guidance reflects reduced capital, operating, general and administrative spending.

The following outlook commentary is focused on the next 12 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 and the pace of growth in global demand. Overall, we expect crude oil price volatility and a modest price improvement in 2016. Anticipated global supply declines, combined with annual increases in demand growth, should support prices in the second half of the year, constrained by the need to draw down surplus crude oil inventories and re-entry of Iranian crude oil into markets. We continue to anticipate supply declines from North American producers as a result of the significant reductions in capital spending. The low crude oil price environment also serves to help boost global economic momentum. However, we believe that economic uncertainty in China may continue and we expect it to impact emerging market demand;
- We expect the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We also expect that the WTI-WCS differential will remain wide due to additional Canadian supply growth and declining U.S. light tight oil supply. However, substantially wider differentials are unlikely due to excess rail capacity.



(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at [cenovus.com](http://cenovus.com).

Refining crack spreads in 2016, as forecasted at March 31, 2016, are expected to strengthen late in the second quarter due to higher seasonal demand for refined products and then decline in the second half of the year.

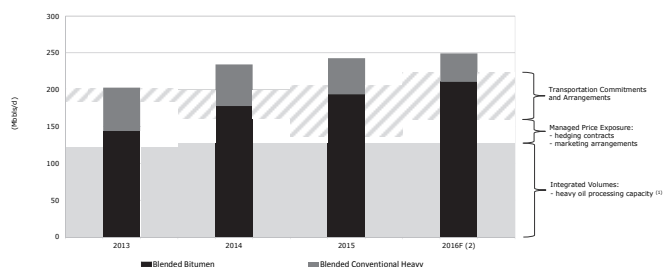
Weak natural gas prices in the first quarter of 2016 reflect lower demand due to warmer than normal winter temperatures and above average storage levels. Pricing is anticipated to improve throughout 2016 due to lower supply growth, although price escalation should be limited by the continued need for coal-to-gas substitution in the power sector.

The average foreign exchange forward price expected over the next 12 months is US\$0.771/C\$. Overall, we expect the Canadian dollar to remain relatively weak which will have a positive impact on our revenues and Operating Cash Flow.

Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian congestion. While we expect to see volatility in crude oil prices, we 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.

#### Protection Against Canadian Congestion



- (1) Excludes additional 18,000 bbls/d heavy oil capacity expected as a result of the Wood River debottlenecking project (expected in the second half of 2016).
- (2) Expected gross production capacity.

### Key Priorities for 2016

#### Maintain Financial Resilience

Maintaining our financial resilience continues to be our top priority, while maintaining safe operations. At March 31, 2016, we had \$3.9 billion of cash on hand and \$4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 16 years, with no debt maturing until the fourth quarter of 2019. Although we have a strong balance sheet, we plan to undertake additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs.

#### Attack Cost Structures

We will continue to focus on reducing our cost structure. We anticipate capital investment in 2016 of \$1.2 billion to \$1.3 billion, a reduction of \$200 million to \$300 million from our original 2016 budget announced in December 2015. We are targeting \$200 million of further savings in operating, general and administrative and compensation costs. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

#### Disciplined and Value-added Growth

We are committed to exercising capital discipline. We will consider expanding existing projects and developing emerging opportunities only when we believe we will generate attractive potential returns for shareholders. Although we have some of the needed fiscal and regulatory clarity at the provincial level, additional certainty around federal fiscal and regulatory regimes, commodity prices and our ability to sustain cost reductions is required. We will only commit to project reactivation if it does not undermine the strength of our balance sheet.

## CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) (unaudited)

For the periods ended March 31,  
(\$ millions, except per share amounts)

	Notes	Three Months Ended	
		2016	2015
<b>Revenues</b>	1		
Gross Sales		2,265	3,165
Less: Royalties		20	24
		2,245	3,141
<b>Expenses</b>	1		
Purchased Product		1,362	1,732
Transportation and Blending		450	528
Operating		451	477
Production and Mineral Taxes		2	5
(Gain) Loss on Risk Management	18	(16)	(6)
Depreciation, Depletion and Amortization	6,11	542	499
Exploration Expense	10	1	-
General and Administrative		60	71
Finance Costs	3	124	121
Interest Income		(11)	(11)
Foreign Exchange (Gain) Loss, Net	4	(403)	515
Research Costs		18	7
(Gain) Loss on Divestiture of Assets	5	-	(16)
<b>Earnings (Loss) Before Income Tax</b>		(335)	(781)
Income Tax Expense (Recovery)	7	(217)	(113)
<b>Net Earnings (Loss)</b>		(118)	(668)
<b>Net Earnings (Loss) Per Share (\$)</b>	8		
Basic		(0.14)	(0.86)
Diluted		(0.14)	(0.86)

See accompanying Notes to Consolidated Financial Statements (unaudited).

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

For the periods ended March 31,  
(\$ millions)

	Notes	Three Months Ended	
		2016	2015
<b>Net Earnings (Loss)</b>		(118)	(668)
<b>Other Comprehensive Income (Loss), Net of Tax</b>	15		
<i>Items That Will Not be Reclassified to Profit or Loss:</i>			
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		(4)	(1)
<i>Items That May be Reclassified to Profit or Loss:</i>			
Change in Value of Available for Sale Financial Assets		(3)	-
Foreign Currency Translation Adjustment		(256)	272
<b>Total Other Comprehensive Income (Loss), Net of Tax</b>		(263)	271
<b>Comprehensive Income (Loss)</b>		(381)	(397)

See accompanying Notes to Consolidated Financial Statements (unaudited).

# CONSOLIDATED BALANCE SHEETS (unaudited)

As at  
(\$ millions)

	Notes	March 31, 2016	December 31, 2015
<b>Assets</b>			
<b>Current Assets</b>			
Cash and Cash Equivalents		3,883	4,105
Accounts Receivable and Accrued Revenues		1,110	1,251
Income Tax Receivable		6	6
Inventories	9	858	810
Risk Management	18,19	176	301
<b>Current Assets</b>		6,033	6,473
Exploration and Evaluation Assets	1,10	1,604	1,575
Property, Plant and Equipment, Net	1,11	16,536	17,335
Income Tax Receivable		-	90
Risk Management	18,19	1	-
Other Assets		84	76
Goodwill	1	242	242
<b>Total Assets</b>		24,500	25,791
<b>Liabilities and Shareholders' Equity</b>			
<b>Current Liabilities</b>			
Accounts Payable and Accrued Liabilities		1,700	1,702
Income Tax Payable		126	133
Risk Management	18,19	26	23
<b>Current Liabilities</b>		1,852	1,858
Long-Term Debt	12	6,113	6,525
Risk Management	18,19	44	7
Decommissioning Liabilities	13	1,786	2,052
Other Liabilities		148	142
Deferred Income Taxes		2,583	2,816
<b>Total Liabilities</b>		12,526	13,400
Shareholders' Equity		11,974	12,391
<b>Total Liabilities and Shareholders' Equity</b>		24,500	25,791

See accompanying Notes to Consolidated Financial Statements (unaudited).

# **CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY** **(unaudited)** (\$ millions)

	Share Capital (Note 14)	Paid in Surplus	Retained Earnings	AOCI <sup>(1)</sup> (Note 15)	Total
<b>As at December 31, 2014</b>	3,889	4,291	1,599	407	10,186
Net Earnings (Loss)	-	-	(668)	-	(668)
Other Comprehensive Income (Loss)	-	-	-	271	271
Total Comprehensive Income (Loss)	-	-	(668)	271	(397)
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	84	-	-	-	84
Stock-Based Compensation Expense	-	15	-	-	15
Dividends on Common Shares	-	-	(222)	-	(222)
<b>As at March 31, 2015</b>	<b>5,436</b>	<b>4,306</b>	<b>709</b>	<b>678</b>	<b>11,129</b>
<b>As at December 31, 2015</b>	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(118)	-	(118)
Other Comprehensive Income (Loss)	-	-	-	(263)	(263)
Total Comprehensive Income (Loss)	-	-	(118)	(263)	(381)
Stock-Based Compensation Expense	-	5	-	-	5
Dividends on Common Shares	-	-	(41)	-	(41)
<b>As at March 31, 2016</b>	<b>5,534</b>	<b>4,335</b>	<b>1,348</b>	<b>757</b>	<b>11,974</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 March 31,  
(\$ millions)

	Notes	Three Months Ended	
		2016	2015
<b>Operating Activities</b>			
Net Earnings (Loss)		(118)	(668)
Depreciation, Depletion and Amortization	6,11	542	499
Exploration Expense	10	1	-
Deferred Income Taxes	7	(190)	(27)
Unrealized (Gain) Loss on Risk Management	18	149	145
Unrealized Foreign Exchange (Gain) Loss	4	(409)	523
(Gain) Loss on Divestiture of Assets	5	-	(16)
Unwinding of Discount on Decommissioning Liabilities	3,13	32	31
Other		19	8
Net Change in Other Assets and Liabilities		(29)	(54)
Net Change in Non-Cash Working Capital		185	(166)
<b>Cash From Operating Activities</b>		<b>182</b>	<b>275</b>
<b>Investing Activities</b>			
Capital Expenditures – Exploration and Evaluation Assets	10	(34)	(74)
Capital Expenditures – Property, Plant and Equipment	11	(289)	(455)
Proceeds From Divestiture of Assets	5	-	16
Net Change in Investments and Other		1	2
Net Change in Non-Cash Working Capital		(47)	(132)
<b>Cash From (Used in) Investing Activities</b>		<b>(369)</b>	<b>(643)</b>
<b>Net Cash Provided (Used) Before Financing Activities</b>		<b>(187)</b>	<b>(368)</b>
<b>Financing Activities</b>			
Net Issuance (Repayment) of Short-Term Borrowings		-	(19)
Common Shares Issued, Net of Issuance Costs		-	1,449
Dividends Paid on Common Shares	8	(41)	(138)
<b>Cash From (Used in) Financing Activities</b>		<b>(41)</b>	<b>1,292</b>
<b>Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency</b>		<b>6</b>	<b>(3)</b>
<b>Increase (Decrease) in Cash and Cash Equivalents</b>		<b>(222)</b>	<b>921</b>
<b>Cash and Cash Equivalents, Beginning of Period</b>		<b>4,105</b>	<b>883</b>
<b>Cash and Cash Equivalents, End of Period</b>		<b>3,883</b>	<b>1,804</b>

See accompanying Notes to Consolidated Financial Statements (unaudited).

## 1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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.

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 cash flow. 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 Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which 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 operating 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.

Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense to conform to the presentation adopted for the year ended December 31, 2015. As a result, for the three months ended March 31, 2015, a recovery of \$1 million was reclassified.

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 March 31, 2016

## A) Results of Operations – Segment and Operational Information

For the three months ended March 31,	Oil Sands		Conventional		Refining and Marketing	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	470	732	274	443	1,588	2,096
Less: Royalties	-	3	20	21	-	-
	470	729	254	422	1,588	2,096
<b>Expenses</b>						
Purchased Product	-	-	-	-	1,428	1,838
Transportation and Blending	404	470	47	58	-	-
Operating	127	144	122	158	203	177
Production and Mineral Taxes	-	-	2	5	-	-
(Gain) Loss on Risk Management	(106)	(90)	(39)	(47)	(20)	(14)
<b>Operating Cash Flow</b>	45	205	122	248	(23)	95
Depreciation, Depletion and Amortization	148	170	322	262	55	46
Exploration Expense	1	-	-	-	-	-
<b>Segment Income (Loss)</b>	(104)	35	(200)	(14)	(78)	49
For the three months ended March 31,	Corporate and Eliminations		Consolidated			
	2016	2015	2016	2015		
<b>Revenues</b>						
Gross Sales	(67)	(106)	2,265	3,165		
Less: Royalties	-	-	20	24		
	(67)	(106)	2,245	3,141		
<b>Expenses</b>						
Purchased Product	(66)	(106)	1,362	1,732		
Transportation and Blending	(1)	-	450	528		
Operating	(1)	(2)	451	477		
Production and Mineral Taxes	-	-	2	5		
(Gain) Loss on Risk Management	149	145	(16)	(6)		
Depreciation, Depletion and Amortization	17	21	542	499		
Exploration Expense	-	-	1	-		
<b>Segment Income (Loss)</b>	(165)	(164)	(547)	(94)		
General and Administrative	60	71	60	71		
Finance Costs	124	121	124	121		
Interest Income	(11)	(11)	(11)	(11)		
Foreign Exchange (Gain) Loss, Net	(403)	515	(403)	515		
Research Costs	18	7	18	7		
(Gain) Loss on Divestiture of Assets	-	(16)	-	(16)		
	(212)	687	(212)	687		
<b>Earnings (Loss) Before Income Tax</b>			(335)	(781)		
Income Tax Expense (Recovery)			(217)	(113)		
<b>Net Earnings (Loss)</b>			(118)	(668)		

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

## B) Financial Results by Upstream Product

For the three months ended March 31,	Crude Oil <sup>(1)</sup>					
	Oil Sands		Conventional		Total	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	465	723	189	315	654	1,038
Less: Royalties	-	3	17	19	17	22
	465	720	172	296	637	1,016
<b>Expenses</b>						
Transportation and Blending	404	470	44	53	448	523
Operating	122	139	78	110	200	249
Production and Mineral Taxes	-	-	2	5	2	5
(Gain) Loss on Risk Management	(106)	(89)	(40)	(37)	(146)	(126)
<b>Operating Cash Flow</b>	<b>45</b>	<b>200</b>	<b>88</b>	<b>165</b>	<b>133</b>	<b>365</b>

(1) Includes NGLs.

For the three months ended March 31,	Natural Gas					
	Oil Sands		Conventional		Total	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	4	6	82	122	86	128
Less: Royalties	-	-	3	2	3	2
	4	6	79	120	83	126
<b>Expenses</b>						
Transportation and Blending	-	-	3	5	3	5
Operating	3	4	42	47	45	51
Production and Mineral Taxes	-	-	-	-	-	-
(Gain) Loss on Risk Management	-	(1)	1	(10)	1	(11)
<b>Operating Cash Flow</b>	<b>1</b>	<b>3</b>	<b>33</b>	<b>78</b>	<b>34</b>	<b>81</b>

For the three months ended March 31,	Other					
	Oil Sands		Conventional		Total	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	1	3	3	6	4	9
Less: Royalties	-	-	-	-	-	-
	1	3	3	6	4	9
<b>Expenses</b>						
Transportation and Blending	-	-	-	-	-	-
Operating	2	1	2	1	4	2
Production and Mineral Taxes	-	-	-	-	-	-
(Gain) Loss on Risk Management	-	-	-	-	-	-
<b>Operating Cash Flow</b>	<b>(1)</b>	<b>2</b>	<b>1</b>	<b>5</b>	<b>-</b>	<b>7</b>

For the three months ended March 31,	Total Upstream					
	Oil Sands		Conventional		Total	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	470	732	274	443	744	1,175
Less: Royalties	-	3	20	21	20	24
	470	729	254	422	724	1,151
<b>Expenses</b>						
Transportation and Blending	404	470	47	58	451	528
Operating	127	144	122	158	249	302
Production and Mineral Taxes	-	-	2	5	2	5
(Gain) Loss on Risk Management	(106)	(90)	(39)	(47)	(145)	(137)
<b>Operating Cash Flow</b>	<b>45</b>	<b>205</b>	<b>122</b>	<b>248</b>	<b>167</b>	<b>453</b>

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

## C) Geographic Information

For the three months ended March 31,	Canada		United States		Consolidated	
	2016	2015	2016	2015	2016	2015
<b>Revenues</b>						
Gross Sales	1,134	1,625	1,131	1,540	2,265	3,165
Less: Royalties	20	24	-	-	20	24
	1,114	1,601	1,131	1,540	2,245	3,141
<b>Expenses</b>						
Purchased Product	373	432	989	1,300	1,362	1,732
Transportation and Blending	450	528	-	-	450	528
Operating	264	307	187	170	451	477
Production and Mineral Taxes	2	5	-	-	2	5
(Gain) Loss on Risk Management	(17)	(1)	1	(5)	(16)	(6)
Depreciation, Depletion and Amortization	488	453	54	46	542	499
Exploration Expense	1	-	-	-	1	-
<b>Segment Income (Loss)</b>	<b>(447)</b>	<b>(123)</b>	<b>(100)</b>	<b>29</b>	<b>(547)</b>	<b>(94)</b>

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

### By Segment

As at	E&E <sup>(1)</sup>		PP&E <sup>(2)</sup>	
	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015
Oil Sands	1,589	1,560	8,912	8,907
Conventional	15	15	3,214	3,720
Refining and Marketing	-	-	4,113	4,398
Corporate and Eliminations	-	-	297	310
<b>Consolidated</b>	<b>1,604</b>	<b>1,575</b>	<b>16,536</b>	<b>17,335</b>

As at	Goodwill		Total Assets	
	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015
Oil Sands	242	242	11,108	11,069
Conventional	-	-	3,311	3,830
Refining and Marketing	-	-	5,552	5,844
Corporate and Eliminations	-	-	4,529	5,048
<b>Consolidated</b>	<b>242</b>	<b>242</b>	<b>24,500</b>	<b>25,791</b>

(1) Exploration and evaluation ("E&E") assets.

(2) Property, plant and equipment ("PP&E").

### By Geographic Region

As at	E&E		PP&E	
	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015
Canada	1,604	1,575	12,516	13,028
United States	-	-	4,020	4,307
<b>Consolidated</b>	<b>1,604</b>	<b>1,575</b>	<b>16,536</b>	<b>17,335</b>

As at	Goodwill		Total Assets	
	March 31, 2016	December 31, 2015	March 31, 2016	December 31, 2015
Canada	242	242	19,495	20,627
United States	-	-	5,005	5,164
<b>Consolidated</b>	<b>242</b>	<b>242</b>	<b>24,500</b>	<b>25,791</b>

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

For the periods ended March 31,	Three Months Ended	
	2016	2015
<b>Capital</b>		
Oil Sands	227	414
Conventional	39	66
Refining and Marketing	52	44
Corporate	5	5
	<b>323</b>	<b>529</b>

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

## 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"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2015, except for income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. 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, 2015, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective April 26, 2016.

## 3. FINANCE COSTS

For the periods ended March 31,	Three Months Ended	
	2016	2015
Interest Expense – Short-Term Borrowings and Long-Term Debt	88	80
Unwinding of Discount on Decommissioning Liabilities (Note 13)	32	31
Other	4	10
	<b>124</b>	<b>121</b>

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

For the periods ended March 31,	Three Months Ended	
	2016	2015
Unrealized Foreign Exchange (Gain) Loss on Translation of:		
U.S. Dollar Debt Issued From Canada	(413)	514
Other	4	9
<b>Unrealized Foreign Exchange (Gain) Loss</b>	<b>(409)</b>	<b>523</b>
<b>Realized Foreign Exchange (Gain) Loss</b>	<b>6</b>	<b>(8)</b>
	<b>(403)</b>	<b>515</b>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

### 5. DIVESTITURES

There were no divestitures for the three months ended March 31, 2016.

In the first quarter of 2015, the Company divested an office building, recording a gain of \$16 million.

### 6. IMPAIRMENTS

#### Cash-Generating Unit ("CGU") Impairments

As indicators of impairment were noted due to a further decline in forward commodity prices, the Company has tested its upstream CGUs for impairment.

#### Key Assumptions

As at March 31, 2016, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal or an evaluation of comparable asset transactions. Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2015 by independent qualified reserves evaluators.

#### Crude Oil and Natural Gas Prices

The forward prices used to determine future cash flows from crude oil and natural gas reserves are:

	Remainder of 2016	2017	2018	2019	2020	Average Annual % Change to 2026
WTI (US\$/barrel) <sup>(1)</sup>	45.00	51.00	59.80	66.30	70.40	3.9%
WCS (C\$/barrel) <sup>(2)</sup>	43.40	50.10	57.00	63.60	65.50	4.0%
AECO (C\$/Mcf) <sup>(3) (4)</sup>	2.10	3.00	3.35	3.65	3.75	3.7%

(1) West Texas Intermediate ("WTI") crude oil.

(2) Western Canadian Select ("WCS") crude oil blend.

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

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

#### Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's independent qualified reserves evaluators in preparing their reserves reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

#### 2016 Impairments

As at March 31, 2016, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of \$170 million. The impairment was recorded as additional depreciation, depletion and amortization ("DD&A") in the Conventional segment. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage. Future cash flows for the Northern Alberta CGU declined due to lower forward crude oil prices.

The recoverable amount was determined using fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with 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. As at March 31, 2016, the recoverable amount of the Northern Alberta CGU was estimated to be approximately \$1.3 billion.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no impairments of goodwill for the three months ended March 31, 2016.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

### Sensitivities

Changes to the assumed discount rate or forward price estimates over the life of the reserves independently would have the following impact on the 2016 impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Price Estimates
Increase to Impairment of PP&E	159	320

### 2015 Impairments

There were no CGU or goodwill impairments for the three months ended March 31, 2015.

## 7. INCOME TAXES

The provision for income taxes is:

For the periods ended March 31,	Three Months Ended	
	2016	2015
Current Tax		
Canada	(27)	(86)
United States	-	-
<b>Total Current Tax Expense (Recovery)</b>	<b>(27)</b>	<b>(86)</b>
<b>Deferred Tax Expense (Recovery)</b>	<b>(190)</b>	<b>(27)</b>
	<b>(217)</b>	<b>(113)</b>

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

For the periods ended March 31,	Three Months Ended	
	2016	2015
<b>Earnings (Loss) Before Income Tax</b>	<b>(335)</b>	<b>(781)</b>
Canadian Statutory Rate	27.0%	25.2%
<b>Expected Income Tax (Recovery)</b>	<b>(90)</b>	<b>(197)</b>
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	(27)	(11)
Non-Deductible Stock-Based Compensation	2	5
Non-Taxable Capital (Gains) Losses	(56)	65
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	(56)	65
Adjustments Arising From Prior Year Tax Filings	-	(11)
Other	10	(29)
<b>Total Tax (Recovery)</b>	<b>(217)</b>	<b>(113)</b>
<b>Effective Tax Rate</b>	<b>64.8%</b>	<b>14.5%</b>



## 8. PER SHARE AMOUNTS

### A) Net Earnings (Loss) Per Share

For the periods ended March 31,	Three Months Ended	
	2016	2015
Net Earnings (Loss) – Basic and Diluted (\$ millions)	(118)	(668)
Basic – Weighted Average Number of Shares (millions)	833.3	778.9
Dilutive Effect of Cenovus TSARs <sup>(1)</sup>	-	-
Dilutive Effect of Cenovus NSRs <sup>(2)</sup>	-	-
Diluted – Weighted Average Number of Shares	833.3	778.9
<b>Net Earnings (Loss) Per Share (\$)</b>		
Basic	(0.14)	(0.86)
Diluted	(0.14)	(0.86)

(1) Tandem stock appreciation rights ("TSARs").

(2) Net settlement rights ("NSRs").

### B) Dividends Per Share

For the three months ended March 31, 2016, the Company paid dividends of \$41 million or \$0.05 per share, all of which was paid in cash (three months ended March 31, 2015 – \$222 million or \$0.2662 per share, including cash dividends of \$138 million).

## 9. INVENTORIES

As a result of a decline in crude oil and refined product prices, Cenovus recorded a write-down of its product inventory of \$31 million from cost to net realizable value as at March 31, 2016 (December 31, 2015 – \$66 million).

## 10. EXPLORATION AND EVALUATION ASSETS

	Total
<b>COST</b>	
As at December 31, 2015	1,575
Additions	34
Exploration Expense	(1)
Change in Decommissioning Liabilities	(4)
<b>As at March 31, 2016</b>	<b>1,604</b>

## 11. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets		Refining Equipment	Other <sup>(1)</sup>	Total
	Development & Production	Other Upstream			
<b>COST</b>					
As at December 31, 2015	31,481	331	5,206	1,037	38,055
Additions	233	-	50	6	289
Change in Decommissioning Liabilities	(256)	-	(13)	(1)	(270)
Exchange Rate Movements and Other	(14)	-	(328)	-	(342)
<b>As at March 31, 2016</b>	<b>31,444</b>	<b>331</b>	<b>4,915</b>	<b>1,042</b>	<b>37,732</b>
<b>ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION</b>					
As at December 31, 2015	18,908	277	896	639	20,720
Depreciation, Depletion and Amortization	291	9	54	15	369
Impairment Losses (Note 6)	170	-	-	3	173
Exchange Rate Movements and Other	(6)	-	(60)	-	(66)
<b>As at March 31, 2016</b>	<b>19,363</b>	<b>286</b>	<b>890</b>	<b>657</b>	<b>21,196</b>
<b>CARRYING VALUE</b>					
As at December 31, 2015	12,573	54	4,310	398	17,335
<b>As at March 31, 2016</b>	<b>12,081</b>	<b>45</b>	<b>4,025</b>	<b>385</b>	<b>16,536</b>

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

## 12. LONG-TERM DEBT

As at	US\$ Principal	March 31, 2016	December 31, 2015
Revolving Term Debt <sup>(1)</sup>	-	-	-
U.S. Dollar Denominated Unsecured Notes	4,750	6,161	6,574
<b>Total Debt Principal</b>		<b>6,161</b>	<b>6,574</b>
Debt Discounts and Transaction Costs		(48)	(49)
		<b>6,113</b>	<b>6,525</b>

(1) Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows the Company to offer, from time to time, up to US\$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018 and replaces the Company's US\$2.0 billion base debt shelf prospectus. In addition, the Company has a \$1.5 billion Canadian base debt shelf prospectus that will expire in July 2016. As at March 31, 2016, there have been no securities issued under either of these prospectuses.

Effective April 22, 2016, the Company extended the maturity date of the \$1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at March 31, 2016, Cenovus had \$4.0 billion available on its committed credit facility.

As at March 31, 2016, the Company is in compliance with all of the terms of its debt agreements.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

### 13. 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:

As at	March 31, 2016
Decommissioning Liabilities, Beginning of Year	2,052
Liabilities Incurred	1
Liabilities Settled	(22)
Change in Estimated Future Cash Flows	(1)
Change in Discount Rate	(274)
Unwinding of Discount on Decommissioning Liabilities	32
Foreign Currency Translation	(2)
<b>Decommissioning Liabilities, End of Period</b>	<b>1,786</b>

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 7.5 percent as at March 31, 2016 (December 31, 2015 – 6.4 percent).

### 14. 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	March 31, 2016	
	Number of Common Shares (Thousands)	Amount
Outstanding, Beginning of Year and End of Period	833,290	5,534

There were no preferred shares outstanding as at March 31, 2016 (December 31, 2015 – nil).

As at March 31, 2016, there were 14 million (December 31, 2015 – 12 million) common shares available for future issuance under the stock option plan.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

### 15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at March 31, 2016				
As at December 31, 2015	(10)	1,014	16	1,020
Other Comprehensive Income (Loss), Before Tax	(5)	(256)	(4)	(265)
Income Tax	1	-	1	2
As at March 31, 2016	(14)	758	13	757
As at March 31, 2015				
As at December 31, 2014	(30)	427	10	407
Other Comprehensive Income (Loss), Before Tax	(1)	272	-	271
Income Tax	-	-	-	-
As at March 31, 2015	(31)	699	10	678

### 16. STOCK-BASED COMPENSATION PLANS

Cenovus has a number of stock-based compensation plans which include stock options with associated NSRs, stock options with associated 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:

	Units Outstanding (thousands)	Units Exercisable (thousands)
As at March 31, 2016		
NSRs	40,321	30,651
TSARs	3,490	3,490
PSUs	4,129	-
RSUs	2,348	-
DSUs	1,566	1,566
	Units Granted (thousands)	Units Vested and Paid Out (thousands)
For the three months ended March 31, 2016		
NSRs	484	-
PSUs	121	979
RSUs	131	32
DSUs	79	-

The weighted average exercise price of NSRs and TSARs as at March 31, 2016 was \$31.44 and \$26.68, respectively.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

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

For the periods ended March 31,	Three Months Ended	
	2016	2015
NSRs	4	11
TSARs	-	(3)
PSUs	(8)	(16)
RSUs	3	3
DSUs	(1)	(2)
<b>Stock-Based Compensation Expense (Recovery)</b>	<b>(2)</b>	<b>(7)</b>
<b>Stock-Based Compensation Costs Capitalized</b>	<b>(1)</b>	<b>(3)</b>
<b>Total Stock-Based Compensation</b>	<b>(3)</b>	<b>(10)</b>

## 17. 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 metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). These metrics 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	March 31, 2016	December 31, 2015
Debt	6,113	6,525
Add (Deduct):		
Cash and Cash Equivalents	(3,883)	(4,105)
Net Debt	2,230	2,420
Debt	6,113	6,525
Shareholders' Equity	11,974	12,391
	18,087	18,916
<b>Debt to Capitalization</b>	<b>34%</b>	<b>34%</b>
Net Debt	2,230	2,420
Shareholders' Equity	11,974	12,391
	14,204	14,811
<b>Net Debt to Capitalization</b>	<b>16%</b>	<b>16%</b>

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

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

As at	March 31, 2016	December 31, 2015
Debt	6,113	6,525
Net Debt	2,230	2,420
Net Earnings	1,168	618
Add (Deduct):		
Finance Costs	485	482
Interest Income	(28)	(28)
Income Tax Expense (Recovery)	(185)	(81)
Depreciation, Depletion and Amortization	2,157	2,114
E&E Impairment	139	138
Unrealized (Gain) Loss on Risk Management	199	195
Foreign Exchange (Gain) Loss, Net	118	1,036
(Gain) Loss on Divestitures of Assets	(2,376)	(2,392)
Other (Income) Loss, Net	2	2
Adjusted EBITDA <sup>(1)</sup>	1,679	2,084
<b>Debt to Adjusted EBITDA</b>	<b>3.6x</b>	<b>3.1x</b>
<b>Net Debt to Adjusted EBITDA</b>	<b>1.3x</b>	<b>1.2x</b>

(1) Calculated on a trailing twelve month basis.

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 facilities or repay existing debt.

Effective April 22, 2016, the Company extended the maturity date of the \$1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at March 31, 2016, Cenovus had \$4.0 billion available on its committed credit facility. In addition, Cenovus had in place a US\$5.0 billion base shelf prospectus and a \$1.5 billion Canadian base debt shelf prospectus, the availability of which are dependent on market conditions. The US\$5.0 billion base shelf prospectus replaces the Company's US\$2.0 billion base debt shelf prospectus which was due to expire July 2016.

Under the committed credit facility, the Company is required to maintain a debt to capitalization ratio not to exceed 65 percent. The Company is well below this limit.

As at March 31, 2016, Cenovus is in compliance with all of the terms of its debt agreements.

## 18. FINANCIAL INSTRUMENTS

Cenovus's consolidated 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, 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 March 31, 2016, the carrying value of Cenovus's long-term debt was \$6,113 million and the fair value was \$5,659 million (December 31, 2015 carrying value – \$6,525 million, fair value – \$6,050 million).

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

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:

As at	March 31, 2016
Fair Value, Beginning of Year	42
Change in Fair Value <sup>(1)</sup>	(4)
<b>Fair Value, End of Period</b>	<b>38</b>

(1) Unrealized gains and losses 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, condensate, power purchase contracts, and interest rate swaps. Crude oil, condensate and, if entered, 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 power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including quoted market prices and interest rate yield curves (Level 2).

### Summary of Unrealized Risk Management Positions

As at	March 31, 2016			December 31, 2015		
	Asset	Liability	Net	Asset	Liability	Net
<b>Commodity Prices</b>						
Crude Oil	177	26	151	301	15	286
Power	-	-	-	-	13	(13)
	177	26	151	301	28	273
<b>Interest Rate</b>	-	44	(44)	-	2	(2)
<b>Total Fair Value</b>	<b>177</b>	<b>70</b>	<b>107</b>	<b>301</b>	<b>30</b>	<b>271</b>

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

As at	March 31, 2016	December 31, 2015
<b>Prices Sourced From Observable Data or Market Corroboration (Level 2)</b>	<b>107</b>	284
<b>Prices Determined From Unobservable Inputs (Level 3)</b>	-	(13)
	<b>107</b>	<b>271</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. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to March 31:

	2016	2015
Fair Value of Contracts, Beginning of Year	271	462
Fair Value of Contracts Realized During the Period <sup>(1)</sup>	(165)	(151)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Period <sup>(2)</sup>	16	6
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	(15)	1
<b>Fair Value of Contracts, End of Period</b>	<b>107</b>	<b>318</b>

(1) Includes a realized loss of \$3 million related to power contracts (2015 – \$3 million loss).

(2) Includes an increase of \$10 million related to power contracts (2015 – \$9 million decrease).

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

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

For the periods ended March 31,	Three Months Ended	
	2016	2015
Realized (Gain) Loss <sup>(1)</sup>	(165)	(151)
Unrealized (Gain) Loss <sup>(2)</sup>	149	145
<b>(Gain) Loss on Risk Management</b>	<b>(16)</b>	<b>(6)</b>

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.

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

## 19. RISK MANAGEMENT

The Company 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, 2015. The Company's exposure to these risks has not changed significantly since December 31, 2015. To manage the Company's exposure to interest rate volatility, the Company has entered into interest rate swap contracts related to future debt issuances. As at March 31, 2016, the Company had a notional amount of US\$350 million in interest rate swaps.

### Net Fair Value of Risk Management Positions

As at March 31, 2016	Notional Volumes	Terms	Average Price	Fair Value
<b>Crude Oil Contracts</b>				
Fixed Price Contracts				
Brent Fixed Price	17,000 bbls/d	January – June 2016	\$75.80/bbl	35
Brent Fixed Price	38,000 bbls/d	January – June 2016	US\$46.62/bbl	26
Brent Fixed Price	10,000 bbls/d	January – December 2016	US\$66.93/bbl	88
Brent Fixed Price	5,000 bbls/d	July – December 2016	\$75.46/bbl	18
WTI Fixed Price	10,000 bbls/d	July – December 2016	US\$39.02/bbl	(8)
WTI Fixed Price	19,000 bbls/d	January – June 2017	US\$45.23/bbl	4
WCS Differential <sup>(1)</sup>	31,600 bbls/d	January – December 2016	US\$(13.96)/bbl	(5)
Brent Collars	10,000 bbls/d	July – December 2016	US\$45.55 – US\$56.55/bbl	13
Other Financial Positions <sup>(2)</sup>				(18)
Crude Oil Fair Value Position				153
<b>Condensate Purchase Contracts</b>				
Mont Belvieu Fixed Price	3,000 bbls/d	January – December 2016	US\$39.20/bbl	(2)
<b>Interest Rate Swaps</b>				(44)

(1) Cenovus entered into fixed-price swaps to protect against widening light/heavy price differentials for heavy crudes.

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



## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2016

### **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 or interest rates, with all other variables held constant. Management believes the price and interest rate 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 based on the risk management positions in place as follows:

#### **Risk Management Positions in Place as at March 31, 2016**

<b>Sensitivity Range</b>		<b>Increase</b>	<b>Decrease</b>
Crude Oil Commodity Price	± US\$10 per bbl Applied to Brent and WTI Hedges	(252)	254
Crude Oil Differential Price	± US\$5 per bbl Applied to Differential Hedges Tied to Production	60	(60)
Condensate Commodity Price	± US\$10 per bbl Applied to Condensate Hedges	17	(17)
Interest Rate Swaps	± 50 Basis Points	46	(54)

## **20. COMMITMENTS AND CONTINGENCIES**

### **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, 2015.

During the three months ended March 31, 2016, the Company's transportation commitments decreased approximately \$1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement. As at March 31, 2016, total transportation commitments were \$26 billion.

As at March 31, 2016, there were outstanding letters of credit aggregating \$211 million issued as security for performance under certain contracts (December 31, 2015 – \$64 million).

### **B) Legal Proceedings**

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Financial Statistics

(\$ millions, except per share amounts)

Revenues	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales						
Upstream	744	4,739	1,002	1,152	1,410	1,175
Refining and Marketing	1,588	8,805	2,030	2,242	2,437	2,096
Corporate and Eliminations	(67)	(337)	(77)	(86)	(68)	(106)
Less: Royalties	20	143	31	35	53	24
<b>Revenues</b>	<b>2,245</b>	<b>13,064</b>	<b>2,924</b>	<b>3,273</b>	<b>3,726</b>	<b>3,141</b>

Operating Cash Flow	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids						
Foster Creek	11	454	72	168	130	84
Christina Lake	34	592	118	159	199	116
Conventional	88	683	132	163	223	165
Natural Gas	34	307	69	79	78	81
Other Upstream Operations	-	18	6	3	2	7
	167	2,054	397	572	632	453
Refining and Marketing	(23)	385	(40)	30	300	95
<b>Operating Cash Flow <sup>(1) (2)</sup></b>	<b>144</b>	<b>2,439</b>	<b>357</b>	<b>602</b>	<b>932</b>	<b>548</b>

Cash Flow	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
Cash from Operating Activities	182	1,474	322	542	335	275
Deduct (Add Back):						
Net Change in Other Assets and Liabilities	(29)	(107)	(26)	(13)	(14)	(54)
Net Change in Non-Cash Working Capital	185	(110)	73	111	(128)	(166)
<b>Cash Flow <sup>(3)</sup></b>	<b>26</b>	<b>1,691</b>	<b>275</b>	<b>444</b>	<b>477</b>	<b>495</b>
Per Share						
- Basic	0.03	2.07	0.33	0.53	0.58	0.64
- Diluted	0.03	2.07	0.33	0.53	0.58	0.64

Earnings	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Operating Earnings (Loss) <sup>(4)</sup></b>	<b>(423)</b>	<b>(403)</b>	<b>(438)</b>	<b>(28)</b>	<b>151</b>	<b>(88)</b>
Per Share						
- Diluted	(0.51)	(0.49)	(0.53)	(0.03)	0.18	(0.11)
<b>Net Earnings (Loss)</b>	<b>(118)</b>	<b>618</b>	<b>(641)</b>	<b>1,801</b>	<b>126</b>	<b>(668)</b>
Per Share						
- Basic	(0.14)	0.75	(0.77)	2.16	0.15	(0.86)
- Diluted	(0.14)	0.75	(0.77)	2.16	0.15	(0.86)

Tax & Exchange Rates	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Effective Tax Rates Using:</b>						
Net Earnings <sup>(5)</sup>	64.8%	(15.1)%				
Operating Earnings, Excluding Divestitures	29.4%	32.4%				
Canadian Statutory Rate <sup>(6)</sup>	27.0%	26.1%				
U.S. Statutory Rate	38.0%	38.0%				
<b>Foreign Exchange Rates (US\$ per C\$1)</b>						
Average	0.728	0.782	0.749	0.764	0.813	0.806
Period End	0.771	0.723	0.723	0.747	0.802	0.789

(1) Operating Cash Flow is a non-GAAP measure defined as revenues less purchased product, transportation and blending, operating expenses and 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 Cash Flow.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

(3) Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(4) Operating Earnings (Loss) is a non-GAAP measure that is 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, 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.

(5) The 2015 effective tax rate reflects an increase to the tax basis of Cenovus's U.S. assets, the two percent increase in the Alberta corporate income tax rate and the benefit from recognition of previously unrecognized capital losses.

(6) On June 29, 2015, the Alberta government enacted a two percent increase in the corporate income tax rate. The rate increase was effective July 1, 2015.

Financial Metrics (Non-GAAP measures)	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
Net Debt to Capitalization <sup>(1) (2)</sup>	16%	16%	16%	13%	28%	27%
Debt to Capitalization <sup>(3) (4)</sup>	34%	34%	34%	33%	35%	35%
Net Debt to Adjusted EBITDA <sup>(1) (5)</sup>	1.3x	1.2x	1.2x	0.8x	1.5x	1.3x
Debt to Adjusted EBITDA <sup>(3) (5)</sup>	3.6x	3.1x	3.1x	2.7x	2.1x	1.9x
Return on Capital Employed <sup>(6)</sup>	8%	5%	5%	6%	(3)%	0%
Return on Common Equity <sup>(7)</sup>	10%	5%	5%	7%	(6)%	(2)%

(1) 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.

(2) Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity.

(3) Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt.

(4) Capitalization is a non-GAAP measure defined as debt plus shareholders' equity.

(5) Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, asset impairments, 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.

(6) 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.

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

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Financial Statistics (continued)

#### Common Share Information

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Common Shares Outstanding (millions)</b>						
Period End	833.3	833.3	833.3	833.3	833.3	828.5
Average - Basic	833.3	818.7	833.3	833.3	828.6	778.9
Average - Diluted	833.3	818.7	833.3	833.3	828.6	778.9
<b>Price Range (\$ per share)</b>						
TSX - C\$						
High	18.15	26.42	22.35	20.91	24.28	26.42
Low	12.70	15.75	16.85	15.75	19.53	20.45
Close	16.90	17.50	17.50	20.24	19.98	21.35
NYSE - US\$						
High	13.97	21.12	17.23	15.97	19.72	21.12
Low	9.10	11.85	12.10	11.85	15.69	16.29
Close	13.00	12.62	12.62	15.16	16.01	16.88
<b>Dividends (\$ per share)</b>	0.0500	0.8524	0.1600	0.1600	0.2662	0.2662
<b>Share Volume Traded (millions)</b>	482.8	1,691.2	377.1	483.3	388.7	442.1

#### Net Capital Investment

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Capital Investment (\$ millions)</b>						
Oil Sands						
Foster Creek	89	403	85	96	73	149
Christina Lake	114	647	132	147	161	207
Total	203	1,050	217	243	234	356
Other Oil Sands	24	135	22	29	26	58
	227	1,185	239	272	260	414
Conventional	39	244	87	55	36	66
Refining and Marketing	52	248	89	67	48	44
Corporate	5	37	13	6	13	5
Capital Investment	323	1,714	428	400	357	529
Acquisitions	-	87	3	84	-	-
Divestitures	-	(3,344)	1	(3,329)	-	(16)
Net Acquisition and Divestiture Activity	-	(3,257)	4	(3,245)	-	(16)
<b>Net Capital Investment</b>	323	(1,543)	432	(2,845)	357	513

### Operating Statistics - Before Royalties

#### Upstream Production Volumes

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Crude Oil and Natural Gas Liquids (bbls/d)</b>						
Oil Sands						
Foster Creek	60,882	65,345	63,680	71,414	58,363	67,901
Christina Lake	77,093	74,975	75,733	75,329	72,371	76,471
	137,975	140,320	139,413	146,743	130,734	144,372
Conventional						
Heavy Oil	31,247	34,888	32,363	33,997	36,099	37,155
Light and Medium Oil	27,121	30,486	26,625	28,491	31,809	35,135
Natural Gas Liquids <sup>(1)</sup>	1,208	1,253	1,155	1,191	1,312	1,358
	59,576	66,627	60,143	63,679	69,220	73,648
Total Crude Oil and Natural Gas Liquids	197,551	206,947	199,556	210,422	199,954	218,020
<b>Natural Gas (MMcf/d)</b>						
Oil Sands	17	19	19	19	21	20
Conventional	391	422	405	411	429	442
Total Natural Gas	408	441	424	430	450	462
<b>Total Production (BOE/d)</b>	265,551	280,447	270,223	282,089	274,954	295,020

<sup>(1)</sup> Natural gas liquids include condensate volumes.

#### Average Royalty Rates

*(Excluding Impact of Realized Gain (Loss) on Risk Management)*

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Oil Sands</b>						
Foster Creek <sup>(1)</sup>	(4.9)%	1.9%	0.7%	0.8%	5.0%	(1.2)%
Christina Lake	1.2%	2.8%	1.9%	3.7%	2.5%	3.1%
<b>Conventional</b>						
Pelican Lake	8.3%	9.0%	8.1%	4.7%	14.3%	6.0%
Weyburn	16.6%	17.7%	17.0%	18.7%	18.4%	16.5%
Other	12.0%	5.2%	12.2%	8.2%	1.2%	3.5%
Natural Gas Liquids	16.1%	5.6%	12.8%	7.1%	2.2%	2.3%
<b>Natural Gas</b>	4.3%	2.5%	3.8%	3.7%	1.2%	1.6%

<sup>(1)</sup> In Q1 2015, regulatory approval was received to include certain capital costs incurred in previous years in the royalty calculation which has resulted in a negative rate. Excluding the credit, the Q1 2015 royalty rate would have been 5.9 percent.

# SUPPLEMENTAL INFORMATION *(unaudited)*

## Operating Statistics - Before Royalties (continued)

Refining	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Refinery Operations <sup>(1)</sup></b>						
Crude Oil Capacity (Mbbbls/d)	460	460	460	460	460	460
Crude Oil Runs (Mbbbls/d)	435	419	405	394	441	439
Heavy Oil	241	200	196	186	200	220
Light/Medium	194	219	209	208	241	219
Crude Utilization	95%	91%	88%	86%	96%	95%
Refined Products (Mbbbls/d)	460	444	430	414	462	469

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

Selected Average Benchmark Prices	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Crude Oil Prices (US\$/bbl)</b>						
Brent	35.08	53.64	44.71	51.17	63.50	55.17
West Texas Intermediate ("WTI")	33.45	48.80	42.18	46.43	57.94	48.63
Differential Brent - WTI	1.63	4.84	2.53	4.74	5.56	6.54
Western Canadian Select ("WCS")	19.21	35.28	27.69	33.16	46.35	33.90
Differential WTI - WCS	14.24	13.52	14.49	13.27	11.59	14.73
Condensate (C5 @ Edmonton)	34.39	47.36	41.67	44.21	57.94	45.62
Differential WTI - Condensate (Premium)/Discount	(0.94)	1.44	0.51	2.22	-	3.01
<b>Refining Margins 3-2-1 Crack Spreads <sup>(1)</sup> (US\$/bbl)</b>						
Chicago	9.58	19.11	14.47	24.67	20.77	16.53
Group 3	10.52	18.16	13.82	22.03	19.34	17.46
<b>Natural Gas Prices</b>						
AECO (C\$/Mcft)	2.11	2.77	2.65	2.80	2.67	2.95
NYMEX (US\$/Mcft)	2.09	2.66	2.27	2.77	2.64	2.98
Differential NYMEX - AECO (US\$/Mcft)	0.56	0.49	0.27	0.61	0.50	0.57

<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").

## Per-unit Results

*(Excluding Impact of Realized Gain (Loss) on Risk Management)*

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Heavy Oil - Foster Creek <sup>(1) (2)</sup> (\$/bbl)</b>						
Price	11.82	33.65	25.09	33.35	48.25	29.42
Royalties	(0.16)	0.47	0.12	0.20	1.97	(0.25)
Transportation and Blending	8.70	8.84	8.53	8.50	9.04	9.39
Operating <sup>(3)</sup>	12.05	12.60	11.66	11.27	13.29	14.50
Netback	(8.77)	11.74	4.78	13.38	23.95	5.78
<b>Heavy Oil - Christina Lake <sup>(1) (2)</sup> (\$/bbl)</b>						
Price	8.85	28.45	21.34	27.46	43.36	23.30
Royalties	0.05	0.67	0.30	0.83	0.99	0.61
Transportation and Blending	5.28	4.72	5.40	5.00	4.29	4.17
Operating <sup>(3)</sup>	7.61	8.01	7.80	7.80	8.20	8.24
Netback	(4.09)	15.05	7.84	13.83	29.88	10.28
<b>Total Heavy Oil - Oil Sands <sup>(1) (2)</sup> (\$/bbl)</b>						
Price	10.13	30.88	23.08	30.35	45.61	26.04
Royalties	(0.04)	0.58	0.22	0.52	1.44	0.22
Transportation and Blending	6.75	6.64	6.85	6.72	6.48	6.50
Operating <sup>(3)</sup>	9.52	10.13	9.59	9.46	10.57	10.99
Netback	(6.10)	13.53	6.42	13.65	27.12	8.33
<b>Heavy Oil - Conventional <sup>(1) (2)</sup> (\$/bbl)</b>						
Price	25.99	39.95	32.84	37.09	52.63	35.85
Royalties	1.40	2.97	2.24	1.73	5.34	2.34
Transportation and Blending	4.77	3.36	3.63	3.36	3.09	3.42
Operating <sup>(3)</sup>	13.98	15.92	15.20	15.59	15.45	17.30
Production and Mineral Taxes	-	0.04	(0.03)	0.07	0.08	0.02
Netback	5.84	17.66	11.80	16.34	28.67	12.77
<b>Total Heavy Oil <sup>(1) (2)</sup> (\$/bbl)</b>						
Price	12.98	32.73	24.87	31.63	47.24	28.15
Royalties	0.22	1.07	0.59	0.75	2.35	0.68
Transportation and Blending	6.39	5.97	6.26	6.08	5.69	5.83
Operating <sup>(3)</sup>	10.32	11.31	10.62	10.62	11.70	12.35
Production and Mineral Taxes	-	0.01	(0.01)	0.01	0.02	-
Netback	(3.95)	14.37	7.41	14.17	27.48	9.29

<sup>(1)</sup> The netbacks do not reflect non-cash write-downs of product inventory.

<sup>(2)</sup> Heavy oil price, and transportation and blending costs exclude the costs of purchased condensate, which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate is as follows:

<b>Cost of Condensate per Barrel of Unblended Crude Oil (\$/bbl)</b>						
Foster Creek	26.13	27.44	25.96	24.20	29.82	30.57
Christina Lake	26.45	29.50	27.39	26.42	32.90	31.60
Heavy Oil - Oil Sands	26.31	28.54	26.72	25.33	31.48	31.14
Heavy Oil - Conventional	10.04	10.94	9.99	9.56	12.42	11.50
Total Heavy Oil	23.39	24.94	23.64	22.34	27.06	26.91

<sup>(3)</sup> Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

# SUPPLEMENTAL INFORMATION *(unaudited)*

## Operating Statistics - Before Royalties (continued)

### Per-unit Results

*(Excluding Impact of Realized Gain (Loss) on Risk Management)*

	2016	2015				
	Q1	Year	Q4	Q3	Q2	Q1
<b>Light and Medium Oil (\$/bbl)</b>						
Price	34.36	50.64	45.35	49.57	61.66	45.81
Royalties	5.18	5.66	6.97	7.02	5.67	3.56
Transportation and Blending	2.73	2.91	2.80	2.88	3.06	2.88
Operating <sup>(1)</sup>	16.34	16.27	17.37	15.92	15.90	16.04
Production and Mineral Taxes	0.82	1.41	0.76	1.60	1.95	1.28
Netback	9.29	24.39	17.45	22.15	35.08	22.05
<b>Total Crude Oil <sup>(2)</sup> (\$/bbl)</b>						
Price	15.91	35.41	27.62	34.08	49.55	31.09
Royalties	0.90	1.75	1.44	1.60	2.88	1.16
Transportation and Blending	5.89	5.51	5.79	5.64	5.27	5.34
Operating <sup>(1)</sup>	11.14	12.05	11.52	11.35	12.37	12.97
Production and Mineral Taxes	0.11	0.22	0.10	0.23	0.33	0.22
Netback	(2.13)	15.88	8.77	15.26	28.70	11.40
<b>Natural Gas Liquids (\$/bbl)</b>						
Price	24.99	30.98	30.70	24.57	39.64	28.51
Royalties	4.03	1.74	3.94	1.75	0.87	0.66
Netback	20.96	29.24	26.76	22.82	38.77	27.85
<b>Total Liquids <sup>(2)</sup> (\$/bbl)</b>						
Price	15.97	35.38	27.63	34.03	49.48	31.08
Royalties	0.92	1.75	1.46	1.60	2.86	1.16
Transportation and Blending	5.85	5.48	5.76	5.61	5.24	5.31
Operating <sup>(1)</sup>	11.08	11.98	11.46	11.28	12.29	12.89
Production and Mineral Taxes	0.11	0.22	0.10	0.23	0.33	0.22
Netback	(1.99)	15.95	8.85	15.31	28.76	11.50
<b>Total Natural Gas (\$/Mcf)</b>						
Price	2.31	2.92	2.78	3.00	2.82	3.05
Royalties	0.09	0.07	0.10	0.11	0.03	0.05
Transportation and Blending	0.10	0.11	0.11	0.10	0.10	0.12
Operating <sup>(1)</sup>	1.23	1.20	1.25	1.16	1.14	1.26
Production and Mineral Taxes	-	0.01	0.02	0.01	0.02	0.01
Netback	0.89	1.53	1.30	1.62	1.53	1.61
<b>Total <sup>(2) (3)</sup> (\$/BOE)</b>						
Price	15.43	30.67	24.78	29.95	40.50	27.73
Royalties	0.82	1.40	1.23	1.36	2.13	0.93
Transportation and Blending	4.51	4.21	4.43	4.35	3.95	4.11
Operating <sup>(1)</sup>	10.14	10.72	10.43	10.18	10.78	11.49
Production and Mineral Taxes	0.08	0.18	0.10	0.19	0.27	0.17
Netback	(0.12)	14.16	8.59	13.87	23.37	11.03
<b>Realized Gain (Loss) on Risk Management</b>						
Liquids (\$/bbl)	8.16	7.51	11.39	10.07	1.75	6.58
Natural Gas (\$/Mcf)	-	0.37	0.42	0.37	0.39	0.29
Total <sup>(3)</sup> (\$/BOE)	6.08	6.11	9.08	8.07	1.92	5.31

<sup>(1)</sup> Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

<sup>(2)</sup> The netbacks do not reflect non-cash write-downs of product inventory.

<sup>(3)</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.

## 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).

### Non-GAAP Measures

This quarterly report contains references to non-GAAP measures as follows:

- Operating cash flow 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 and is used to provide a consistent measure of the cash generating performance of the company's assets for comparability of Cenovus's underlying financial performance between periods. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.
- Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim and annual Consolidated Financial Statements. Cash flow is a 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.
- Free cash flow is defined as cash flow less capital investment.
- Operating earnings is used to provide a consistent measure of the comparability of the company's underlying financial performance between periods by removing non-operating items. Operating earnings is defined as earnings before income tax excluding gain (loss) on discontinuance, 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 to capitalization, net debt to capitalization, debt to adjusted EBITDA and net debt to adjusted EBITDA are ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. 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. Capitalization is defined as debt plus shareholders' equity. Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity. Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill and asset impairments, unrealized gains or losses on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss, calculated on a trailing 12-month basis.

These measures do not have a standardized meaning as prescribed by IFRS and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, refer to Cenovus's most recent Management's Discussion and Analysis (MD&A) available at [cenovus.com](http://cenovus.com).

### OIL AND GAS INFORMATION

**Netbacks** reported in this quarterly report are calculated as set out in the Annual Information Form (AIF). Heavy oil prices and transportation and blending costs exclude the costs of purchased condensate, which is blended with heavy oil. For the first quarter 2016, the cost of condensate on a per barrel of unblended crude oil basis was as follows: Christina Lake - \$26.45 and Foster Creek - \$26.13.

## FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the company's experience and perception of historical trends. Forward-looking information in this document is identified by words such as "aim", "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "guidance", "budget", "position", "priority", "project", "capacity", "could", "should", "focus", "potential", "may", "strategy", "forward", "opportunity", "on track" or similar expressions and includes suggestions of future outcomes, including statements about: measures planned to help maintain the company's financial resilience; projections contained in the company's 2016 guidance; forecast operating and financial results; the strength of the company's financial position; projected shareholder value; commodity prices; planned capital expenditures and reductions; expectations regarding improving cost structures, process optimization, and forecast cost reductions, including the expected benefits of and sustainability thereof; expected timelines for achievement of cost reductions and status with respect to such timelines; expected future production, including the timing, stability or growth thereof; expected differences in the company's potential performance for the remainder of 2016 relative to the first quarter; expected correlation of cash flow to WTI price improvement; development strategy and related schedules; project capacities; targets and expectations with respect to the company's net debt to capitalization, net debt to adjusted EBITDA, debt to capitalization and debt to adjusted EBITDA ratios; the company's position to mitigate the impact of swings in the Canadian light-heavy oil price differential; and the company's financial resilience generally. Readers are cautioned not to place undue reliance on forward-looking information as the company's 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: assumptions inherent in Cenovus's 2016 guidance, available at [cenovus.com](http://cenovus.com); projected capital investment levels, the flexibility of 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; the company's ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; the company's ability to generate sufficient cash flow to meet its current and future obligations; and other risks and uncertainties described from time to time in the filings Cenovus makes with securities regulatory authorities.

2016 guidance (as updated on February 11, 2016), available at [cenovus.com](http://cenovus.com), assumes: Brent of US\$52.75/bbl, WTI of US\$49.00/bbl; WCS of US\$34.50/bbl; NYMEX of US\$2.50/MMBtu; AECO of \$2.50/GJ; Chicago 3-2-1 crack spread of US\$12.00/bbl; and an exchange rate of \$0.75 US\$/C\$.

The risk factors and uncertainties that could cause Cenovus's actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of the company's risk management program, including the impact of derivative financial instruments, the success of the company's hedging strategies and the sufficiency of its liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in the company's 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 to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization 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 dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; the company's ability to maintain relationships with partners and to successfully manage and operate the company's integrated business; reliability of 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

acceptance in the market; risks associated with the 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 costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other 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; changes in the company's 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 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, its financial results and its consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which Cenovus operates; 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 the company.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of Cenovus's material risk factors, see "Risk Factors" in the company's AIF or Form 40-F for the period ended December 31, 2015, and "Risk Management" in the Management's Discussion and Analysis for the three months ended March 31, 2016, all of which are available on SEDAR at [sedar.com](http://sedar.com), EDGAR at [sec.gov](http://sec.gov) and on Cenovus's website at [cenovus.com](http://cenovus.com).

## 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
MMbbls	million barrels	MMBtu	million British thermal units
BOE	barrel of oil equivalent	GJ	gigajoule
BOE/d	Barrel of oil equivalent per day	AECO	Alberta Energy Company
MBOE	thousand barrel of oil equivalent	NYMEX	New York Mercantile Exchange
MMBOE	million barrel of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	Trademark of Cenovus Energy Inc.



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