# MANAGEMENT'S DISCUSSION AND ANALYSIS

# FOR THE YEAR ENDED DECEMBER 31, 2015

**WHERE TO FIND:**



*This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 10, 2016, should be read in conjunction with our December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 10, 2016, unless otherwise indicated. This MD&A 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 Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 10, 2016. 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, EDGAR at sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.*

**Basis of Presentation**

*This MD&A and the 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

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2015, we had a market capitalization of approximately $15 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 in 2015 was approximately 207,000 barrels per day and our average natural gas production was 441 MMcf per day. Our refineries processed an average of 419,000 gross barrels per day of crude oil feedstock into an average of 444,000 gross barrels per day of refined products.

### Our Key Message for 2015

2015 was a challenging year for the oil and gas industry as the low commodity price environment prompted significant reductions in capital spending programs and extensive efforts to reduce costs. The deterioration of crude oil prices resulted in a significant decline in our cash flow and earnings.

During these volatile times, Cenovus has remained focused on delivering value through preserving financial resilience, achieving sustainable cost reductions and exercising capital discipline. Together, our common share issuance and the sale of our royalty interest and mineral fee title lands business raised cash proceeds of approximately $4.7 billion. These transactions significantly strengthened our balance sheet and our net debt to capitalization ratio was 16 percent at December 31, 2015. We also reduced our capital, operating and general and administrative spending, capturing savings of approximately $540 million, relative to our budget.

We expect commodity prices to remain low for the foreseeable future and continue to make adjustments to our capital spending and cost structure. For more information, we direct our readers to review the news release for our revised 2016 guidance dated February 11, 2016. The news release is available on our website at cenovus.com, on SEDAR at sedar.com and on EDGAR at sec.gov.

### Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving stronger 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 production 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 December 31, 2015, we had $4.1 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 ensure our continued financial flexibility, 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 2015, we paid a dividend of $0.8524 per share compared with $1.0648 per share in 2014 (2013 – $0.968 per share). We reduced our dividend by 40 percent in the third quarter of 2015, from $0.2662 per share to $0.16 per share, as part of our strategy to maintain our long-term financial resilience. Our dividend was further reduced to $0.05 per share in the first quarter of 2016. 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:

| | 2015 | | |
|---|---|---|---|
| | Ownership Interest (percent) | Net Production Volumes (bbls/d) | Gross Production Volumes (bbls/d) |
| **Existing Projects** | | | |
| Foster Creek | 50 | 65,345 | 130,690 |
| Christina Lake | 50 | 74,975 | 149,950 |
| Narrows Lake | 50 | - | - |
| **Emerging Projects** | | | |
| 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.

| | 2015 | |
|---|---|---|
| ($ millions) | Crude Oil | Natural Gas |
| Operating Cash Flow | 1,046 | 10 |
| Capital Investment | 1,184 | 1 |
| **Operating Cash Flow Net of Related Capital Investment** | (138) | 9 |

### *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.

| | 2015 | |
|---|---|---|
| ($ millions) | Crude Oil (1) | Natural Gas |
| Operating Cash Flow | 683 | 297 |
| Capital Investment | 231 | 13 |
| **Operating Cash Flow Net of Related Capital Investment** | 452 | 284 |

(1) *Includes NGLs.*

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("$CO_2$") 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.

| | 2015 | |
|---|---|---|
| | Ownership Interest (percent) | Gross Nameplate Capacity (Mbbls/d) |
| Wood River | 50 | 314 |
| Borger | 50 | 146 |

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 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) | 2015 |
|---|---|
| Operating Cash Flow | 385 |
| Capital Investment | 248 |
| **Operating Cash Flow Net of Related Capital Investment** | 137 |

## 2015 HIGHLIGHTS

In 2015, Cenovus delivered on the commitments we made to our shareholders. We met our production targets, achieved significant sustainable cost savings in all areas of our business and strengthened our balance sheet. However, our financial results continued to be significantly impacted by low crude oil prices. Average crude oil benchmark prices declined approximately 50 percent from 2014. The expectation of sustained low commodity prices resulted in asset impairments of $338 million, further decreasing our earnings.

During 2015, Cenovus remained focused on delivering value through preserving financial resilience, achieving sustainable cost reductions and exercising capital discipline. We captured savings of approximately $540 million, relative to our budget, by reducing our capital, operating, and general and administrative spending. Approximately 50 percent of these savings came from lower than budgeted operating costs and 40 percent from reduced capital expenditures, including supply chain management initiatives.

In 2015, we also:

- Issued 67.5 million common shares at $22.25 per share for net proceeds of $1.4 billion;
- Completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion;
- Renegotiated our $3.0 billion committed credit facility, extending the maturity date to November 30, 2019 and added a new $1.0 billion tranche under the same facility with a maturity date of November 30, 2017;
- Reduced capital investment by 44 percent or $1.3 billion, compared with 2014;
- Realized gains of $656 million from crude oil and natural gas risk management activities;
- Reduced our workforce by 24 percent to align with our more moderate approach to oil sands expansions;
- Decreased our total crude oil operating costs by 20 percent or $228 million, compared with 2014;
- Increased proved bitumen reserves by 11 percent primarily due to approval of an area expansion at Christina Lake;
- Closed the purchase of a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options;
- Received regulatory approval for Christina Lake phase H, a 50,000 gross barrels per day phase; and
- Reduced our annual dividend from $1.0648 per share to $0.8524 per share.

## OPERATING RESULTS

Our upstream assets continued to perform well in 2015. Total crude oil production averaged 206,947 barrels per day during the year.

### Crude Oil Production Volumes

| (barrels per day) | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| **Oil Sands** | | | | | |
| Foster Creek | 65,345 | 10% | 59,172 | 11% | 53,190 |
| Christina Lake | 74,975 | 9% | 69,023 | 40% | 49,310 |
| | 140,320 | 9% | 128,195 | 25% | 102,500 |
| **Conventional** | | | | | |
| Heavy Oil | 34,888 | (12)% | 39,546 | (2)% | 40,245 |
| Light and Medium Oil | 30,486 | (12)% | 34,531 | (3)% | 35,467 |
| NGLs (1) | 1,253 | 3% | 1,221 | 15% | 1,063 |
| | 66,627 | (12)% | 75,298 | (2)% | 76,775 |
| **Total Crude Oil Production** | 206,947 | 2% | 203,493 | 14% | 179,275 |

*(1) NGLs include condensate volumes.*

Foster Creek production increased in 2015 due to the ramp-up of production from phase F and production from additional wells, partially offset by the impact of a forest fire in the second quarter, which decreased full-year production by approximately 2,600 barrels per day. Fourth quarter production was lower compared with 2014. 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 fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

Production from Christina Lake increased compared with 2014 due to production from additional wells and improved performance of our facilities.

In 2015, our Conventional crude oil production decreased from 2014. An increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production also declined due to reduced capital investment. Divested assets contributed 2,555 barrels per day (2014 – 6,532 barrels per day) to annual production.

### Natural Gas Production Volumes

| (MMcf per day) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Conventional | 422 | 466 | 508 |
| Oil Sands | 19 | 22 | 21 |
| | 441 | 488 | 529 |

Our natural gas production declined 10 percent in 2015. Production decreased primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business, which produced 10 MMcf per day during the year (2014 – 20 MMcf per day).

### Oil and Gas Reserves

Our proved bitumen reserves increased 11 percent to approximately 2.2 billion barrels and our proved plus probable bitumen reserves remained at approximately at 3.3 billion barrels. Additional information about our reserves and resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

### Operating Netbacks

| | Crude Oil (1) ($/bbl) | | | Natural Gas ($/Mcf) | | |
|---|---|---|---|---|---|---|
| | 2015 | 2014 | 2013 | 2015 | 2014 | 2013 |
| Price (2) | 35.38 | 71.35 | 67.01 | 2.92 | 4.37 | 3.20 |
| Royalties | 1.75 | 6.18 | 5.01 | 0.07 | 0.08 | 0.04 |
| Transportation and Blending (2) (3) | 5.48 | 2.98 | 3.12 | 0.11 | 0.12 | 0.11 |
| Operating Expenses (4) | 11.98 | 15.40 | 15.49 | 1.20 | 1.22 | 1.16 |
| Production and Mineral Taxes | 0.22 | 0.50 | 0.48 | 0.01 | 0.05 | 0.02 |
| **Netback Excluding Realized Risk Management** | 15.95 | 46.29 | 42.91 | 1.53 | 2.90 | 1.87 |
| Realized Risk Management Gain (Loss) | 7.51 | 0.50 | 1.09 | 0.37 | 0.04 | 0.32 |
| **Netback Including Realized Risk Management** | 23.46 | 46.79 | 44.00 | 1.90 | 2.94 | 2.19 |

*(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 $21.09 per barrel (2014 – $30.49 per barrel; 2013 – $28.33 per barrel).*
*(3) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.*
*(4) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

Our average crude oil netback in 2015, excluding realized risk management gains and losses, decreased significantly compared with 2014. Lower sales prices, consistent with the decline in benchmark prices, were partially offset by weakening of the Canadian dollar relative to the U.S. dollar and a decline in royalties and operating costs. The weakening of the Canadian dollar compared with 2014 had a positive impact on our crude oil price of approximately $4.81 per barrel.

In 2015, 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

In 2015, we successfully completed planned turnarounds at both of our Borger and Wood River refineries and received permit approval for the Wood River debottlenecking project.

| | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| Crude Oil Runs [1] (Mbbls/d) | **419** | **(1)%** | 423 | (4)% | 442 |
| Heavy Crude Oil [1] | **200** | **1%** | 199 | (10)% | 222 |
| Refined Product [1] (Mbbls/d) | **444** | **-** | 445 | (4)% | 463 |
| Crude Utilization [1] (percent) | **91** | **(1)%** | 92 | (5)% | 97 |

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

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 [1]

| | Q4 2015 | Percent Change | Q4 2014 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|---|
| **Crude Oil Prices** (US$/bbl) | | | | | | |
| Brent | | | | | | |
| Average | **44.71** | **(42)%** | 76.98 | **53.64** | 99.51 | 108.76 |
| End of Period | **37.28** | **(35)%** | 57.33 | **37.28** | 57.33 | 110.80 |
| WTI | | | | | | |
| Average | **42.18** | **(42)%** | 73.15 | **48.80** | 93.00 | 97.97 |
| End of Period | **37.04** | **(30)%** | 53.27 | **37.04** | 53.27 | 98.42 |
| Average Differential Brent-WTI | **2.53** | **(34)%** | 3.83 | **4.84** | 6.51 | 10.79 |
| WCS [2] | | | | | | |
| Average | **27.69** | **(53)%** | 58.91 | **35.28** | 73.60 | 72.77 |
| End of Period | **24.98** | **(34)%** | 37.59 | **24.98** | 37.59 | 74.80 |
| Average Differential WTI-WCS | **14.49** | **2%** | 14.24 | **13.52** | 19.40 | 25.20 |
| Condensate (C5 @ Edmonton) [3] | | | | | | |
| Average | **41.67** | **(41)%** | 70.57 | **47.36** | 92.95 | 101.69 |
| Average Differential WTI-Condensate (Premium)/Discount | **0.51** | **(80)%** | 2.58 | **1.44** | 0.05 | (3.72) |
| Average Differential WCS-Condensate (Premium)/Discount | **(13.98)** | **20%** | (11.66) | **(12.08)** | (19.35) | (28.92) |
| **Average Refined Product Prices** (US$/bbl) | | | | | | |
| Chicago Regular Unleaded Gasoline ("RUL") | **55.24** | **(32)%** | 81.26 | **67.68** | 107.40 | 116.35 |
| Chicago Ultra-low Sulphur Diesel ("ULSD") | **59.23** | **(42)%** | 101.48 | **68.12** | 117.55 | 126.31 |
| **Refining Margin: Average 3-2-1 Crack Spreads** (US$/bbl) | | | | | | |
| Chicago | **14.47** | **(1)%** | 14.60 | **19.11** | 17.61 | 21.77 |
| Group 3 | **13.82** | **4%** | 13.28 | **18.16** | 16.27 | 20.80 |
| **Average Natural Gas Prices** | | | | | | |
| AECO (C$/Mcf) | **2.65** | **(34)%** | 4.01 | **2.77** | 4.42 | 3.17 |
| NYMEX (US$/Mcf) | **2.27** | **(43)%** | 4.00 | **2.66** | 4.42 | 3.65 |
| Basis Differential NYMEX-AECO (US$/Mcf) | **0.27** | **(39)%** | 0.44 | **0.49** | 0.40 | 0.58 |
| **Foreign Exchange Rates** (US$ per C$1) | | | | | | |
| Average | **0.749** | **(15)%** | 0.881 | **0.782** | 0.905 | 0.971 |

*(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 2015 was $45.12 per barrel (2014 – $81.33 per barrel; 2013 – $74.94 per barrel); fourth quarter average WCS benchmark price was $36.97 per barrel (2014 – $66.87 per barrel).*
*(3) The average Canadian dollar condensate benchmark price for 2015 was $60.56 per barrel (2014 – $102.71 per barrel; 2013 – $104.73 per barrel); fourth quarter average condensate benchmark price was $55.63 per barrel (2014 – $80.10 per barrel).*

### *Crude Oil Benchmarks*

The average Brent, WTI and WCS benchmark prices continued to be impacted by a 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 sustained 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. Despite significantly lower crude oil prices and increased global demand in 2015, the imbalance has only slightly improved. Economic uncertainty in China, resilient U.S. production, continued strong production from Saudi Arabia and Iraq, as well as concerns regarding the return of Iranian production have contributed to sustained low crude oil prices.

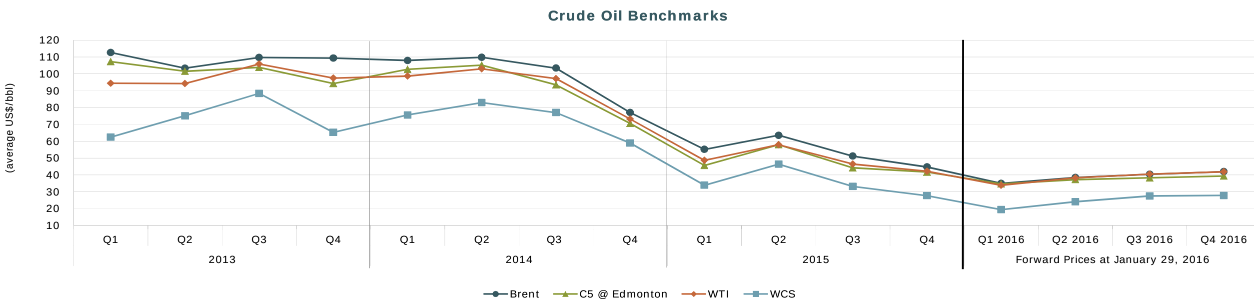
The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices.

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 2014. WTI benchmark prices strengthened relative to Brent as a result of high global crude oil inventory levels and continued strong demand in the U.S., leaving transportation costs as the primary driver of the Brent-WTI differential.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in 2015. The narrower differential resulted primarily from increased demand for WCS due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity and the slow return of heavy crude oil supply forced offline due to forest fires in northeastern Alberta during the second quarter of 2015.

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 value attributed to transporting the condensate to Edmonton.

The average WCS-Condensate differential narrowed in 2015 due to condensate supply growth as well as improved diluent transportation infrastructure for condensate imports into Alberta and heavy oil exports to market.



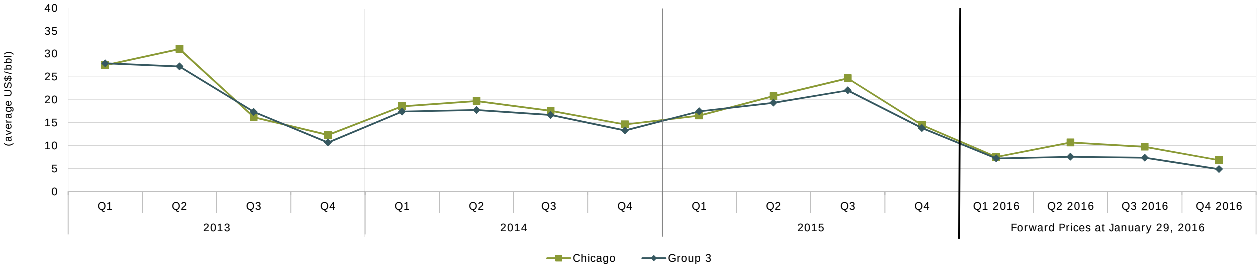

### *Refining Benchmarks*

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 increased in 2015 compared with 2014 driven by stronger product demand. Average Group 3 crack spreads increased as a major unplanned refinery outage in August 2015 caused product inventory drawdowns during the driving season.

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.

Refining 3-2-1 Crack Spread Benchmarks




### *Natural Gas Benchmarks*

Average natural gas prices decreased in 2015 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 2015 compared with 2014, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices, strengthening of the U.S. economy, and Canadian political and economic uncertainty. The weakening of the Canadian dollar compared with 2014 had a positive impact of approximately $1,772 million on our revenues and also resulted in $1,064 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

Sustained low commodity prices in 2015 significantly impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

| ($ millions, except per share amounts) | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| **Revenues** | **13,064** | **(33)%** | 19,642 | 5% | 18,657 |
| **Operating Cash Flow** [(1) (2)] | **2,439** | **(42)%** | 4,179 | (7)% | 4,484 |
| **Cash Flow** [(1)] | **1,691** | **(51)%** | 3,479 | (4)% | 3,609 |
| Per Share – Diluted | **2.07** | **(55)%** | 4.59 | (4)% | 4.76 |
| **Operating Earnings (Loss)** [(1)] | **(403)** | **(164)%** | 633 | (46)% | 1,171 |
| Per Share – Diluted | **(0.49)** | **(158)%** | 0.84 | (46)% | 1.55 |
| **Net Earnings (Loss)** | **618** | **(17)%** | 744 | 12% | 662 |
| Per Share – Basic | **0.75** | **(23)%** | 0.98 | 11% | 0.88 |
| Per Share – Diluted | **0.75** | **(23)%** | 0.98 | 13% | 0.87 |
| **Total Assets** | **25,791** | **4%** | 24,695 | (2)% | 25,224 |
| **Total Long-Term Financial Liabilities** [(3)] | **6,552** | **19%** | 5,484 | (10)% | 6,113 |
| **Capital Investment** [(4)] | **1,714** | **(44)%** | 3,051 | (6)% | 3,262 |
| **Dividends** | | | | | |
| Cash Dividends | **528** | **(34)%** | 805 | 10% | 732 |
| In Shares from Treasury | **182** | **-** | - | - | - |
| Per Share | **0.8524** | **(20)%** | 1.0648 | 10% | 0.968 |

*(1) Non-GAAP measure defined in this MD&A.*
*(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*
*(3) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.*
*(4) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.*

## Revenues

| ($ millions) | 2015 vs. 2014 | 2014 vs. 2013 |
|---|---|---|
| **Revenues, Comparative Year** | **19,642** | 18,657 |
| Increase (Decrease) due to: | | |
| Oil Sands | **(1,799)** | 1,020 |
| Conventional | **(1,401)** | 220 |
| Refining and Marketing | **(3,853)** | (48) |
| Corporate and Eliminations | **475** | (207) |
| **Revenues, End of Year** | **13,064** | 19,642 |

Combined Oil Sands and Conventional revenues declined 41 percent in 2015 due to lower crude oil blend and natural gas sales prices, partially offset by higher crude oil sales volumes, weakening of the Canadian dollar relative to the U.S. dollar and lower royalties. The sale of our royalty interest and mineral fee title lands business also reduced revenues.

Revenues from our Refining and Marketing segment decreased 30 percent from 2014. 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 2015 decreased 36 percent from 2014, primarily due to a decline in sales prices, partially offset by an increase in purchased crude oil volumes.

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

Overall, revenues increased in 2014 compared with 2013 primarily due to higher blended crude oil sales volumes and higher average sales prices for blended crude oil and natural gas, partially offset by an increase in royalties.

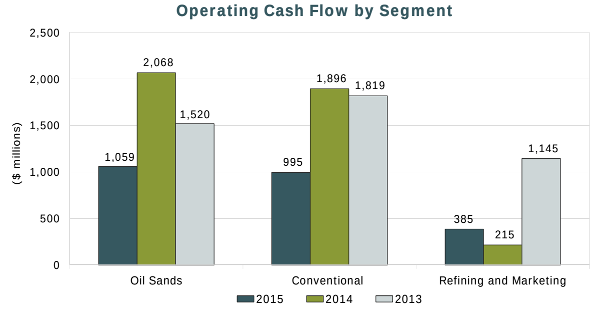
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

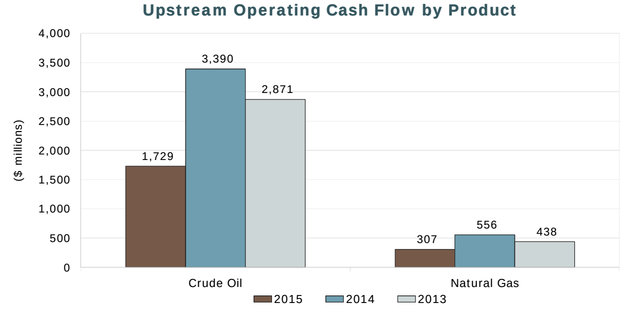
## Operating Cash Flow

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) | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Revenues** | **13,401** | 20,454 | 19,262 |
| (Add) Deduct: | | | |
| Purchased Product | **7,709** | 11,767 | 11,004 |
| Transportation and Blending | **2,045** | 2,477 | 2,074 |
| Operating Expenses (1) | **1,846** | 2,051 | 1,787 |
| Production and Mineral Taxes | **18** | 46 | 35 |
| Realized (Gain) Loss on Risk Management Activities | **(656)** | (66) | (122) |
| **Operating Cash Flow** | **2,439** | 4,179 | 4,484 |

(1) *For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*



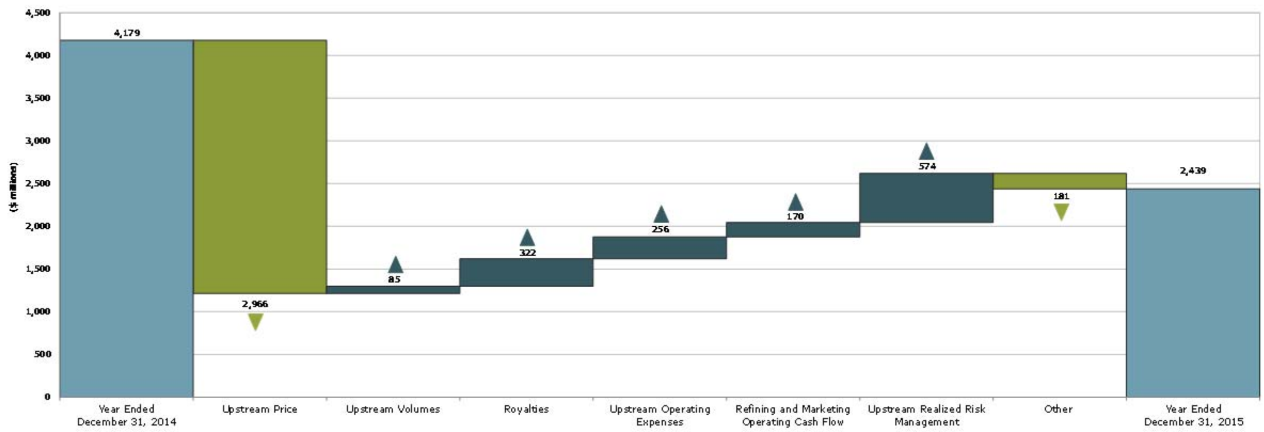

Operating Cash Flow declined 42 percent in 2015 primarily due to:

- A 50 percent decrease in our average crude oil sales price and a 33 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices; and
- A 10 percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $613 million, excluding Refining and Marketing, compared with $39 million in 2014;
- Lower royalties primarily due to a decrease in crude oil sales prices;
- A decrease of $3.42 per barrel in crude oil operating expenses primarily due to a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs;
- Higher Operating Cash Flow from Refining and Marketing as a result of improved margins on the sale of secondary products, such as coke and asphalt, and weakening of the Canadian dollar relative to the U.S. dollar, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and higher operating costs; and
- An inventory write-down of $66 million compared with an inventory write-down of $131 million in 2014.

### *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) | **2015** | 2014 | 2013 |
|---|---|---|---|
| **Cash From Operating Activities** | **1,474** | 3,526 | 3,539 |
| (Add) Deduct: | | | |
| Net Change in Other Assets and Liabilities | **(107)** | (135) | (120) |
| Net Change in Non-Cash Working Capital | **(110)** | 182 | 50 |
| **Cash Flow** | **1,691** | 3,479 | 3,609 |

In 2015, Cash Flow decreased due to a combination of lower Operating Cash Flow, as discussed above, and higher current income tax. Current income tax rose due to the timing of recognition of partnership income for tax purposes.

## 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) | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Earnings, Before Income Tax** | **537** | 1,195 | 1,094 |
| Add (Deduct): | | | |
| Unrealized Risk Management (Gain) Loss (1) | **195** | (596) | 415 |
| Non-operating Unrealized Foreign Exchange (Gain) Loss (2) | **1,064** | 458 | 52 |
| Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable | **-** | - | 146 |
| (Gain) Loss on Divestiture of Assets | **(2,392)** | (156) | 1 |
| **Operating Earnings (Loss), Before Income Tax** | **(596)** | 901 | 1,708 |
| Income Tax Expense (Recovery) | **(193)** | 268 | 537 |
| **Operating Earnings (Loss)** | **(403)** | 633 | 1,171 |

*(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 2014 primarily due to lower Cash Flow, and higher depreciation, depletion and amortization ("DD&A") and exploration expense due to asset impairments. These items were partially offset by a recovery of deferred income tax compared with an expense in 2014 and a goodwill impairment of $497 million recorded in 2014.

## Net Earnings

| ($ millions) | 2015 vs. 2014 | 2014 vs. 2013 |
|---|---|---|
| **Net Earnings, Comparative Year** | **744** | 662 |
| Increase (Decrease) due to: | | |
| Operating Cash Flow (1) (2) | **(1,740)** | (305) |
| Corporate and Eliminations: | | |
| Unrealized Risk Management Gain (Loss) | **(791)** | 1,011 |
| Unrealized Foreign Exchange Gain (Loss) | **(686)** | (371) |
| Gain (Loss) on Divestiture of Assets | **2,236** | 157 |
| Expenses (2) (3) | **46** | 191 |
| Depreciation, Depletion and Amortization | **(168)** | (113) |
| Goodwill Impairment | **497** | (497) |
| Exploration Expense | **(52)** | 28 |
| Income Tax Expense | **532** | (19) |
| **Net Earnings, End of Year** | **618** | 744 |

*(1) Non-GAAP measure defined in this MD&A.*
*(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*
*(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 2015, Net Earnings declined as an after-tax gain of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business, and a deferred tax recovery related to non-operating items compared with an expense in 2014, were more than offset by:

- A decline in Operating Earnings, as discussed above;
- Unrealized risk management losses, after-tax, of $141 million (2014 – unrealized gains of $444 million); and
- Non-operating unrealized foreign exchange losses, after-tax, of $1,064 million (2014 – $458 million).

Net Earnings increased in 2014 compared with 2013 primarily due to unrealized risk management gains compared with losses in 2013, a gain on the sale of non-core assets and no realized foreign exchange loss in 2014 related to the Partnership Contribution Receivable, partially offset by a decline in operating earnings and higher non-operating unrealized foreign exchange losses.

## Net Capital Investment

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Oil Sands | **1,185** | 1,986 | 1,885 |
| Conventional | **244** | 840 | 1,189 |
| Refining and Marketing | **248** | 163 | 107 |
| Corporate and Eliminations | **37** | 62 | 81 |
| **Capital Investment** | **1,714** | 3,051 | 3,262 |
| Acquisitions | **87** | 18 | 32 |
| Divestitures | **(3,344)** | (277) | (283) |
| **Net Capital Investment (1)** | **(1,543)** | 2,792 | 3,011 |

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

Capital investment in 2015 declined 44 percent as we reduced our capital investment in light of the low commodity price environment.

In 2015, Oil Sands capital investment focused on sustaining capital related to existing production, the phase G expansion at Foster Creek, and Christina Lake optimization project and phase F expansion. We drilled 164 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 $CO_2$ enhanced oil recovery project at Weyburn and drilling activity in the second half of the year at our tight oil projects in southeast Alberta.

Capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving 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.

### *Acquisitions and Divestitures*

In 2015, we completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion, recording an after-tax gain of approximately $1.9 billion. The sale included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on Cenovus's working interest production on these fee lands and a Gross Overriding Royalty ("GORR") on production from our Pelican Lake and Weyburn assets were also included.

In 2015, we purchased a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options.

Divestitures in 2014 primarily included the sale of certain of our Bakken assets in southeastern Saskatchewan and the sale of certain of our Wainwright assets in Alberta for net proceeds of $269 million, resulting in a gain of $153 million. In 2013, divestitures included the sale of our Lower Shaunavon asset for net proceeds of $241 million, resulting in a loss of $2 million.

We had no material acquisitions in 2014 or 2013.

## 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) | **2015** | 2014 | 2013 |
|---|---|---|---|
| Cash Flow [(1)] | **1,691** | 3,479 | 3,609 |
| Capital Investment (Committed and Growth) | **1,714** | 3,051 | 3,262 |
| Free Cash Flow [(2)] | **(23)** | 428 | 347 |
| Cash Dividends | **528** | 805 | 732 |
| | **(551)** | (377) | (385) |

*(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) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Oil Sands | 3,001 | 4,800 | 3,780 |
| Conventional | 1,595 | 2,996 | 2,776 |
| Refining and Marketing | 8,805 | 12,658 | 12,706 |
| Corporate and Eliminations | (337) | (812) | (605) |
| | 13,064 | 19,642 | 18,657 |

## 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 in 2015 compared with 2014 include:

- Production at Foster Creek increasing 10 percent, to an average of 65,345 barrels per day, primarily as a result of the ramp-up of phase F, partially offset by the impact of a forest fire in the second quarter. Fourth quarter production was lower compared with 2014. 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 fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production;
- Christina Lake production increasing nine percent, to an average of 74,975 barrels per day primarily due to production from additional wells, and improved performance of our facilities;
- Completion of the optimization project at Christina Lake, which is expected to add 22,000 barrels per day of gross production capacity. Incremental production from the project is anticipated in 2016;
- Reducing our crude oil operating costs by $104 million or $3.37 per barrel; and
- Receiving regulatory approval for Christina Lake phase H, a 50,000 gross barrels per day phase.

## Oil Sands – Crude Oil

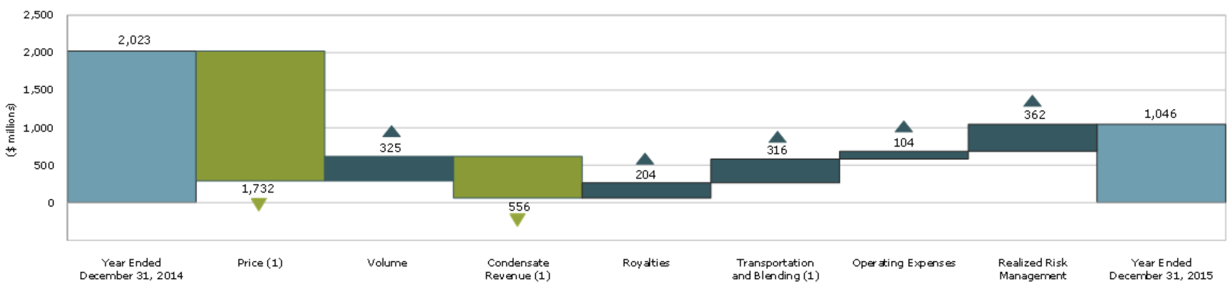
### *Financial and Per-unit Results*

| ($ millions, unless otherwise noted) | 2015 | 2015 $ per-unit [1] | 2014 | 2014 $ per-unit [1] | 2013 | 2013 $ per-unit [1] |
|---|---|---|---|---|---|---|
| **Gross Sales** | **3,000** | 60 | 4,963 | 109 | 3,850 | 103 |
| Less: Royalties | **29** | 1 | 233 | 5 | 131 | 4 |
| **Revenues** | **2,971** | 59 | 4,730 | 104 | 3,719 | 99 |
| **Expenses** | | | | | | |
| Transportation and Blending | **1,814** | 36 | 2,130 | 47 | 1,748 | 47 |
| Operating [2] | **511** | 10 | 615 | 14 | 527 | 14 |
| (Gain) Loss on Risk Management | **(400)** | (8) | (38) | (1) | (33) | (1) |
| **Operating Cash Flow** | **1,046** | 21 | 2,023 | 44 | 1,477 | 39 |
| Capital Investment | **1,184** | | 1,980 | | 1,880 | |
| **Operating Cash Flow Net of Related Capital Investment** | **(138)** | | 43 | | (403) | |

*(1) Per-unit amounts are calculated on an unblended crude oil basis.*
*(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments in 2015 and 2013. Proceeds from our common share issuance and the sale of our royalty interest and mineral fee title lands business also contributed to funding our capital investment in 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*

In 2015, our average crude oil sales price was $30.88 per barrel, a 53 percent decrease from 2014 as the prices we received were adversely impacted by the worldwide low commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by 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. The WCS-CDB differential narrowed by 40 percent to a discount of US$2.37 per barrel (2014 – a discount of US$3.94 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In 2015, 86 percent of our Christina Lake production was sold as CDB (2014 – 88 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*

| (barrels per day) | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| Foster Creek | **65,345** | **10%** | 59,172 | 11% | 53,190 |
| Christina Lake | **74,975** | **9%** | 69,023 | 40% | 49,310 |
| | **140,320** | **9%** | 128,195 | 25% | 102,500 |

Foster Creek production increased in 2015 primarily due to the ramp-up of phase F and production from additional wells. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately 18 months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when production at Foster Creek was shut down for 11 full days as a safety precaution due to a nearby forest fire. The forest fire decreased production by approximately 2,600 barrels per day. Fourth quarter production was lower compared with 2014. 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 fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

Production from Christina Lake increased in 2015 due to production from additional wells, phase E reaching nameplate production capacity in the second quarter of 2014, and improved 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) | **2015** | 2014 | 2013 |
|---|---|---|---|
| Foster Creek | **1.9** | 8.8 | 5.8 |
| Christina Lake | **2.8** | 7.5 | 6.8 |

Royalties decreased $204 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, the royalty calculation was based on gross revenues as compared with a calculation based on net profits for 2014. In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate. Excluding the credit, the effective royalty rate for Foster Creek would have been 3.1 percent in 2015. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

### Expenses

*Transportation and Blending*

Transportation and blending costs decreased $316 million or 15 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes, consistent with the rise in production. In 2015, we recorded a $44 million (2014 – $6 million) write-down of our blended crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher-priced inventory and the transportation costs associated with moving the condensate to our oil sands projects.

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. 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.

We incurred higher transportation charges on the Trans Mountain pipeline system, with our long-term commitment for firm service. Transportation costs also increased as lower volumes moved by rail were more than offset by new lease costs for railcars, and higher loading fees and storage costs. In 2015, we transported an average of 7,057 gross barrels per day of crude oil by rail, consisting of 43 unit train shipments (2014 – 7,325 gross barrels per day, 47 unit train shipments).

*Operating*

Primary drivers of our operating expenses for 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $104 million or $3.37 per barrel, primarily as a result of lower natural gas prices that reduced fuel costs, higher production, a decline in workover activities and efforts from our supply chain management.

### Per-unit Operating Expenses

| ($/bbl) | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| **Foster Creek** | | | | | |
| Fuel | **2.80** | **(37)%** | 4.46 | 55% | 2.88 |
| Non-fuel (1) | **9.80** | **(18)%** | 11.89 | (7)% | 12.74 |
| Total | **12.60** | **(23)%** | 16.35 | 5% | 15.62 |
| **Christina Lake** | | | | | |
| Fuel | **2.20** | **(40)%** | 3.65 | 20% | 3.03 |
| Non-fuel (1) | **5.81** | **(22)%** | 7.44 | (20)% | 9.34 |
| Total | **8.01** | **(28)%** | 11.09 | (10)% | 12.37 |
| **Total** | **10.13** | **(25)%** | 13.50 | (4)% | 14.07 |

(1) *For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

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

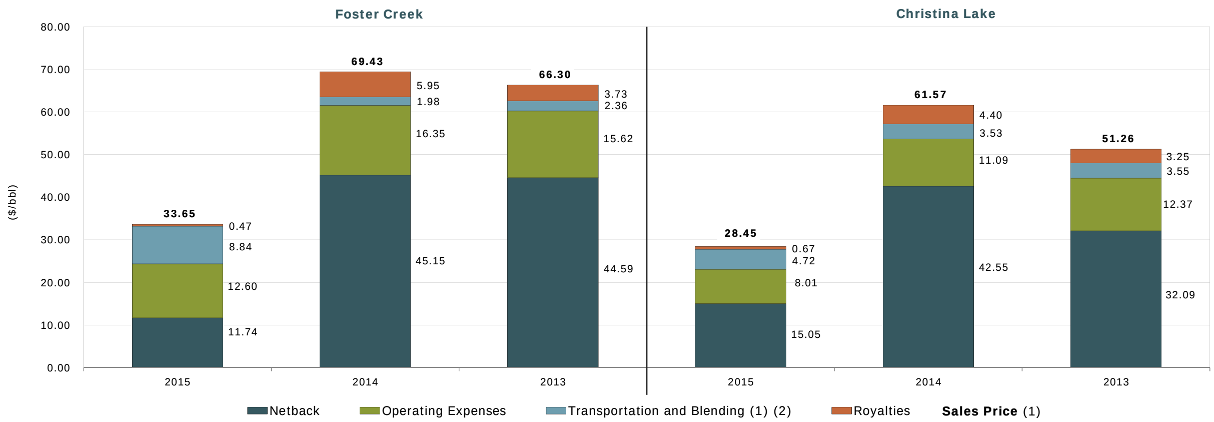
- Higher production volumes;
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Lower electricity costs.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.11 per barrel of incremental costs associated with the shut-down due to a nearby forest fire that occurred in the second quarter of 2015.

At Christina Lake, fuel costs decreased due to lower natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:

- Increased production;
- Lower workover costs related to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities and no turnaround costs in 2015.

## Operating Netbacks




(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 2015 was $27.44 per barrel (2014 – $42.01 per barrel; 2013 – $42.41 per barrel) for Foster Creek, and $29.50 per barrel (2014 – $45.45 per barrel; 2013 – $45.25 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

(2) *The netbacks do not reflect non-cash write-downs of product inventory in 2015 and 2014. There was no product inventory write-down recorded in 2013.*

### *Risk Management*

Risk management activities in 2015 resulted in realized gains of $400 million (2014 – $38 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 2015, net of internal usage, was 19 MMcf per day (2014 – 22 MMcf per day). Operating Cash Flow was $10 million in 2015 (2014 – $46 million) primarily due to the decline in natural gas sales prices.

### Oil Sands – Capital Investment

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Foster Creek | **403** | 796 | 797 |
| Christina Lake | **647** | 794 | 688 |
| | **1,050** | 1,590 | 1,485 |
| Narrows Lake | **47** | 175 | 152 |
| Telephone Lake | **24** | 112 | 93 |
| Grand Rapids | **38** | 63 | 39 |
| Other [(1)] | **26** | 46 | 116 |
| **Capital Investment [(2)]** | **1,185** | 1,986 | 1,885 |

(1) *Includes new resource plays and Athabasca natural gas.*
(2) *Includes expenditures on PP&E and E&E assets.*

#### *Existing Projects*

Capital investment at Foster Creek in 2015 focused on sustaining capital related to existing production, expansion phase G and the drilling of stratigraphic test wells. In 2015, capital investment declined mainly due to the start-up of phase F in the third quarter of 2014.

In 2015, Christina Lake capital investment focused on sustaining capital related to existing production, expansion phases F and G, and the optimization project. The optimization project has been completed and is expected to add 22,000 barrels per day of gross production capacity. Incremental production from the optimization project is anticipated in 2016. Capital investment in 2015 decreased from 2014 due to lower spending on phase F facilities, partially offset by increased investment in sustaining activities.

Capital investment at Narrows Lake in 2015 was mainly on detailed engineering and construction wind-down. Capital investment declined in 2015 compared with 2014 due to the suspension of construction at Narrows Lake.

#### *Emerging Projects*

In 2015, Telephone Lake capital investment focused primarily on completing front-end engineering work on the central processing facility and preliminary infrastructure development. Capital spending decreased in 2015 as we did not drill any stratigraphic test wells during the year (2014 – 45 stratigraphic test wells).

Capital investment at Grand Rapids in 2015 focused on continued operation of the SAGD pilot project. A third well pair was drilled, completed and commenced steam circulation. Capital investment decreased in 2015 compared with 2014 as there were no stratigraphic test wells drilled in 2015 (2014 – 10 stratigraphic test wells) and all work related to the dismantling and removal of an existing SAGD facility purchased in 2014 was completed.

#### *Drilling Activity [(1)]*

| | Gross Stratigraphic Test Wells [(2)] | | | Gross Production Wells [(3)] | | |
|---|---|---|---|---|---|---|
| | **2015** | 2014 | 2013 | **2015** | 2014 | 2013 |
| Foster Creek | **124** | 165 | 112 | **28** | 63 | 56 |
| Christina Lake | **40** | 57 | 74 | **67** | 67 | 35 |
| | **164** | 222 | 186 | **95** | 130 | 91 |
| Narrows Lake | **-** | 22 | 26 | **-** | - | - |
| Telephone Lake | **-** | 45 | 28 | **-** | - | - |
| Grand Rapids | **-** | 10 | 3 | **1** | - | - |
| Other | **-** | 21 | 96 | **-** | - | - |
| | **164** | 320 | 339 | **96** | 130 | 91 |

(1) *In addition to the drilling activity included within the table, we drilled eight gross service wells in 2015 (2014 – three gross service wells; 2013 – 27 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 2015, we drilled seven wells (2014 – 14 wells; 2013 – 24 wells) and commissioned our second SkyStrat™ drilling rig.*
(3) *SAGD well pairs are counted as a single producing well.*

Stratigraphic test wells were drilled at Foster Creek and Christina Lake to help identify well pad locations for sustaining wells and near-term expansion phases.

### Future Capital Investment

Due to our expectation that low commodity prices will persist for an extended period, we have adopted a more moderate and staged approach to future oil sands expansions. Expanding existing projects and developing emerging projects will depend upon commodity prices, achieving further cost reductions as well as additional 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. 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. Construction work on phase G was deferred earlier 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 completing 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. As of February 2016, further activity in respect of the SAGD pilot at Grand Rapids has been deferred in response to the current low commodity price environment.

### DD&A and Exploration Expense

### *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.

In 2015, Oil Sands DD&A increased $72 million primarily due to higher sales volumes and the impairment of a sulphur recovery facility for $16 million. The average depletion rate was approximately $11.65 per barrel compared with $10.85 per barrel in 2014 as the impact of higher PP&E and future development expenditures were only partially offset by proved reserves additions. Future development costs, which compose approximately 60 percent of the depletable base, increased due to the inclusion of Foster Creek phase J.

### *Exploration Expense*

In 2015, $67 million of previously capitalized E&E costs, related to exploration assets within the Northern Alberta cash-generating unit ("CGU"), were deemed not to be technically feasible and commercially viable and were recorded as exploration expense. In 2014, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense.

## CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a $CO_2$ 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.

On July 29, 2015, we completed the sale of our royalty interest and mineral fee title lands business, which included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on our working interest production from these fee lands and a GORR on production from our Pelican Lake and Weyburn assets were also included in the sale. We received cash proceeds of approximately $3.3 billion and recorded an after-tax gain of approximately $1.9 billion. Associated third-party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day.

Additional developments in our Conventional segment in 2015 compared with 2014 include:

- Crude oil production averaging 66,627 barrels per day, decreasing 12 percent, as an increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production also declined due to reduced capital investment;
- Reducing our crude oil operating costs by $124 million or $2.77 per barrel;
- Generating Operating Cash Flow net of capital investment of $751 million, a decrease of 29 percent;
- Recording an impairment of $184 million associated with our Northern Alberta CGU due to lower crude oil prices and a slowing down of the development plan; and
- Recording an exploration expense of $71 million related to previously capitalized exploration assets deemed not to be technically feasible and commercially viable.

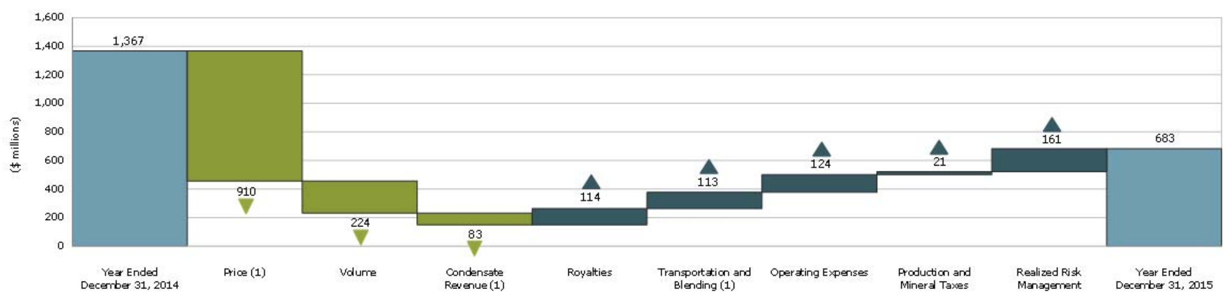
## Conventional – Crude Oil

### *Financial and Per-unit Results*

| ($ millions, unless otherwise noted) | 2015 | $ per-unit (1) | 2014 | $ per-unit (1) | 2013 | $ per-unit (1) |
|---|---|---|---|---|---|---|
| **Gross Sales** | **1,239** | 51 | 2,456 | 90 | 2,373 | 85 |
| Less: Royalties | **103** | 4 | 217 | 8 | 196 | 7 |
| **Revenues** | **1,136** | 47 | 2,239 | 82 | 2,177 | 78 |
| **Expenses** | | | | | | |
| Transportation and Blending | **213** | 9 | 326 | 12 | 305 | 11 |
| Operating (2) | **381** | 15 | 505 | 19 | 489 | 18 |
| Production and Mineral Taxes | **16** | 1 | 37 | 1 | 32 | 1 |
| (Gain) Loss on Risk Management | **(157)** | (6) | 4 | - | (43) | (2) |
| **Operating Cash Flow** | **683** | 28 | 1,367 | 50 | 1,394 | 50 |
| Capital Investment | **231** | | 812 | | 1,167 | |
| **Operating Cash Flow Net of Related Capital Investment** | **452** | | 555 | | 227 | |

*(1) Per-unit amounts are calculated on an unblended crude oil basis.*
*(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

## 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 was $44.63 per barrel in 2015, 45 percent lower than in 2014, consistent with the decline in crude oil benchmark prices.

### *Production Volumes*

| (barrels per day) | 2015 | Percent Change | 2014 | Percent Change | 2013 |
|---|---|---|---|---|---|
| Heavy Oil | **34,888** | **(12)%** | 39,546 | (2)% | 40,245 |
| Light and Medium Oil | **30,486** | **(12)%** | 34,531 | (3)% | 35,467 |
| NGLs | **1,253** | **3%** | 1,221 | 15% | 1,063 |
| | **66,627** | **(12)%** | 75,298 | (2)% | 76,775 |

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production also declined due to reduced capital investment. Divested assets contributed 2,555 barrels per day (2014 – 6,532 barrels per day) to annual production.

### *Condensate*

Revenues represent the total value of blended crude oil sold and include the value of condensate.

### *Royalties*

Royalties decreased $114 million primarily due to lower realized sales prices, 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. For 2015, the effective crude oil royalty rate for our Conventional properties was 9.9 percent (2014 – 10.1 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 was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

In 2015, 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.

## Expenses

### *Transportation and Blending*

Transportation and blending costs decreased $113 million. Blending costs declined primarily due to lower condensate prices. In 2015, we recorded a $7 million (2014 – $12 million) write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in volumes moved by rail. We transported an average of 597 barrels per day of crude oil by rail (2014 – 2,706 barrels per day).

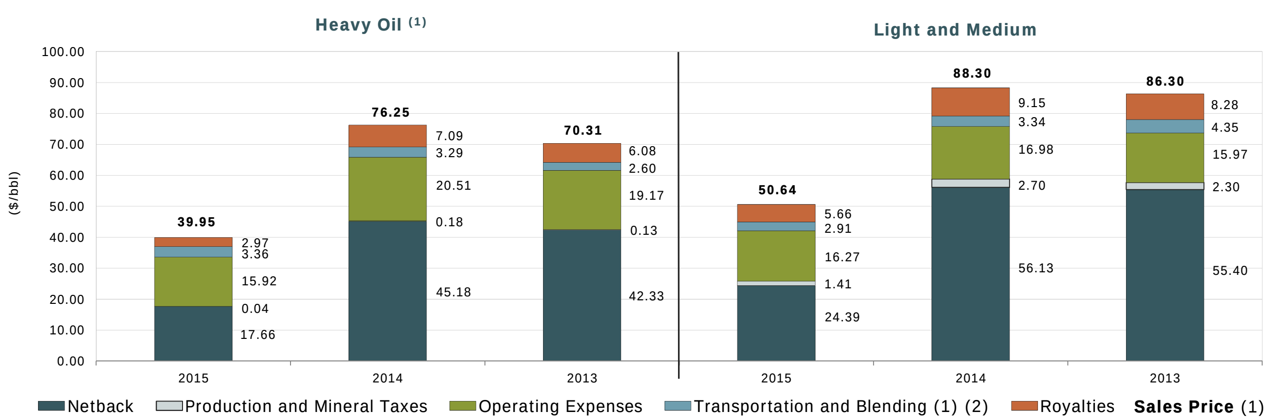
### *Operating*

Primary drivers of our operating expenses for 2015 were workforce costs, workover activities, electricity and chemical consumption. Operating expenses declined $124 million or $2.77 per barrel.

The per-unit decline was primarily due to:
- A decline in workover costs and lower repairs and maintenance as a result of focusing on critical activities and achieving operational efficiencies;
- Lower trucking expenses as we added pipeline infrastructure;
- Lower chemical costs associated with reduced polymer consumption; and
- Lower electricity costs as a result of a decrease in consumption due in part to the disposition of non-core assets, and a decline in price.

These decreases were partially offset by lower production.

## Operating Netbacks




(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 $10.94 per barrel (2014 – $15.71 per barrel; 2013 – $14.60 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

(2) *The netbacks do not reflect non-cash write-downs of product inventory in 2015 and 2014. There was no product inventory write-down recorded in 2013.*

*Risk Management*

Risk management activities for 2015 resulted in realized gains of $157 million (2014 – realized losses of $4 million), consistent with our contract prices exceeding average benchmark prices.

## Conventional – Natural Gas

### *Financial Results*

| ($ millions) | **2015** | 2014 | 2013 |
|---|---|---|---|
| **Gross Sales** | **450** | 744 | 594 |
| Less: Royalties | **11** | 12 | 8 |
| **Revenues** | **439** | 732 | 586 |
| **Expenses** | | | |
| Transportation and Blending | **17** | 20 | 20 |
| Operating [(1)] | **175** | 198 | 208 |
| Production and Mineral Taxes | **2** | 9 | 3 |
| (Gain) Loss on Risk Management | **(52)** | (5) | (61) |
| **Operating Cash Flow** | **297** | 510 | 416 |
| Capital Investment | **13** | 28 | 22 |
| **Operating Cash Flow Net of Related Capital Investment** | **284** | 482 | 394 |

*(1) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

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

### Revenues

*Pricing*

In 2015, our average natural gas sales price decreased 33 percent to $2.93 per Mcf, consistent with the decline in the AECO benchmark price.

*Production*

Production decreased nine percent to 422 MMcf per day in 2015 (2014 – eight percent to 466 MMcf per day) due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 10 MMcf per day in 2015 (2014 – 20 MMcf per day).

*Royalties*

Royalties decreased slightly compared with 2014. Reduced royalties as a result of lower prices and production declines were offset by additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business. The average royalty rate in 2015 was 2.7 percent (2014 – 1.6 percent).

### Expenses

*Transportation*

In 2015, transportation costs decreased as a result of lower production volumes, partially offset by higher pipeline tariffs.

*Operating*

Primary drivers of our operating expenses were property taxes and lease costs, and workforce. In 2015, operating expenses decreased by $23 million primarily due to lower workforce costs, and repairs and maintenance, partially offset by lower production volumes.

*Risk Management*

Risk management activities resulted in realized gains of $52 million in 2015 (2014 – $5 million), consistent with our contract prices exceeding average benchmark prices.

## Conventional – Capital Investment

| ($ millions) | **2015** | 2014 | 2013 |
|---|---|---|---|
| Heavy Oil | **63** | 338 | 598 |
| Light and Medium Oil | **168** | 474 | 569 |
| Natural Gas | **13** | 28 | 22 |
| **Capital Investment [(1)]** | **244** | 840 | 1,189 |

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

Capital investment declined in 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment. Capital investment in 2015 was primarily related to maintenance capital, spending for our $CO_2$ enhanced oil recovery project at Weyburn and drilling activities at our tight oil projects in southeast Alberta.

### *Drilling Activity*

| (net wells, unless otherwise stated) | **2015** | 2014 | 2013 |
|---|---|---|---|
| Crude Oil | **32** | 126 | 212 |
| Recompletions | **724** | 803 | 751 |
| Gross Stratigraphic Test Wells | **13** | 30 | 54 |
| Other [1] | **3** | 40 | 77 |

*(1) Includes dry and abandoned, observation and service wells.*

Drilling activity declined in 2015, reflecting the decision to suspend the majority of our 2015 drilling program in southern Alberta and Saskatchewan as a result of the low commodity price environment. In the second half of the year, modest drilling activities resumed at our tight oil projects in southeast Alberta and at our $CO_2$ enhanced oil recovery project at Weyburn.

### Future Capital Investment

Consistent with our expectation that commodity prices will continue to be low for a prolonged period of time, we are taking a more moderate approach to developing our conventional crude oil opportunities. 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, Goodwill Impairment and Exploration Expense

#### *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 $66 million in 2015 as a decline in sales volumes was more than offset by impairment losses and higher DD&A rates. The average depletion rate increased approximately five percent in 2015 as the impact of lower proved reserves due to the slowdown of our development plans was partially offset by lower PP&E. Future development costs, which compose approximately 30 percent of the depletable base, were consistent with 2014.

In 2015, we recorded an impairment loss of $184 million associated with our Northern Alberta CGU due to lower crude oil prices and a slowing down of our development plan. In 2014, an impairment loss of $52 million was recorded on equipment and in 2013, we recorded a $57 million impairment loss related to our Lower Shaunavon asset sold in July 2013.

#### *Goodwill Impairment*

In 2014, we recorded $497 million of goodwill impairment associated with our Pelican Lake property. There was no goodwill impairment in 2015 or 2013.

#### *Exploration Expense*

In 2015, $71 million (2014 – $82 million) of previously capitalized E&E costs related to exploration assets within the Northern Alberta and Saskatchewan CGUs that were deemed not to be technically feasible and commercially viable and were recorded as exploration expense.

In 2013, $50 million of exploration expense and $64 million of pre-exploration expense was recorded.

## 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.

Significant developments in our Refining and Marketing segment in 2015 compared with 2014 include:

- Closing the purchase of a crude-by-rail terminal for $75 million, plus adjustments. We commenced operating the terminal in August 2015 and loaded 34 unit trains, including 20 unit trains for third parties;
- Operating Cash Flow increasing 79 percent to $385 million primarily due to improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and higher operating costs;
- Receiving permit approval for the Wood River debottlenecking project;
- Successfully completing planned turnarounds at both of our Borger and Wood River refineries; and
- Exporting crude oil from the U.S. Gulf Coast to broaden market access for our crude oil production.

### Refinery Operations [1]

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Crude Oil Capacity** [2] (Mbbls/d) | **460** | 460 | 457 |
| **Crude Oil Runs** (Mbbls/d) | **419** | 423 | 442 |
| Heavy Crude Oil | **200** | 199 | 222 |
| Light/Medium | **219** | 224 | 220 |
| **Refined Products** (Mbbls/d) | **444** | 445 | 463 |
| Gasoline | **228** | 231 | 232 |
| Distillate | **137** | 137 | 144 |
| Other | **79** | 77 | 87 |
| **Crude Utilization** (percent) | **91** | 92 | 97 |

*(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 refine heavy crude oil demonstrates our ability to economically integrate our heavy crude oil production. The discount of WCS relative to WTI benefits our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In 2015, crude oil runs and refined product output were slightly lower compared with 2014. The unplanned outages and planned turnarounds at both of our refineries in 2015 had a similar impact on crude oil runs and refined product output as the outage and turnarounds in 2014.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. 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. The volume of heavy crude oil processed in 2015 increased slightly from 2014.

### Financial Results

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Revenues | **8,805** | 12,658 | 12,706 |
| Purchased Product | **7,709** | 11,767 | 11,004 |
| **Gross Margin** | **1,096** | 891 | 1,702 |
| **Expenses** | | | |
| Operating [1] | **754** | 703 | 538 |
| (Gain) Loss on Risk Management | **(43)** | (27) | 19 |
| **Operating Cash Flow** | **385** | 215 | 1,145 |
| Capital Investment | **248** | 163 | 107 |
| **Operating Cash Flow Net of Related Capital Investment** | **137** | 52 | 1,038 |

*(1) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

#### *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 2015, the increase in gross margin was primarily due to:

- Improved margins on the sale of our secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the decline in WTI;
- Weakening of the Canadian dollar relative to the U.S. dollar; and
- An inventory write-down of $15 million related to our refined product inventory, compared with a write-down of $113 million in 2014.

The increase in gross margin was partially offset by higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential.

The weakening of the Canadian dollar relative to the U.S. dollar in 2015, compared with 2014, had a positive impact of approximately $143 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 2015, the cost of our RINs was $200 million (2014 – $123 million). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues and purchased product from third-party crude oil and natural gas sales undertaken by the marketing group in 2015 decreased 36 percent and 38 percent, respectively, from 2014, primarily due to a decline in sales prices, partially offset by an increase in purchased crude oil volumes.

#### *Operating Expense*

Primary drivers of operating expenses in 2015 were maintenance, labour, utilities and supplies. Reported operating expenses increased compared with 2014 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.

### Refining and Marketing – Capital Investment

| ($ millions) | **2015** | 2014 | 2013 |
|---|---|---|---|
| Wood River Refinery | **162** | 101 | 64 |
| Borger Refinery | **78** | 61 | 42 |
| Marketing | **8** | 1 | 1 |
| | **248** | 163 | 107 |

Capital expenditures in 2015 focused on the debottlenecking project at Wood River, capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives. We received permit approval in the first quarter of 2015 for the Wood River debottlenecking project and start-up 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 3 to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $35 million in 2015, 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 2015, our risk management activities resulted in $195 million of unrealized losses (2014 – $596 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

| ($ millions) | **2015** | 2014 | 2013 |
|---|---|---|---|
| General and Administrative (1) | **335** | 379 | 365 |
| Finance Costs | **482** | 445 | 529 |
| Interest Income | **(28)** | (33) | (96) |
| Foreign Exchange (Gain) Loss, Net | **1,036** | 411 | 208 |
| Research Costs | **27** | 15 | 24 |
| (Gain) Loss on Divestiture of Assets | **(2,392)** | (156) | 1 |
| Other (Income) Loss, Net | **2** | (4) | 2 |
| | **(538)** | 1,057 | 1,033 |

*(1) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

#### *Expenses*

### General and Administrative

Primary drivers of our general and administrative expenses in 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased by $87 million primarily due to workforce reductions and lower employee long-term incentive costs driven by the decline in our share price, offset by severance costs of approximately $43 million. Lower discretionary spending also contributed to the reduction of general and administration costs.

### Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $37 million in 2015 compared with 2014 as weakening of the Canadian dollar relative to the U.S. dollar increased interest incurred on our U.S. dollar denominated debt, partially offset by lower interest incurred on the Partnership Contribution Payable, which was repaid in the first quarter of 2014.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2015 was 5.3 percent (2014 – 5.0 percent).

### Foreign Exchange

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Unrealized Foreign Exchange (Gain) Loss | 1,097 | 411 | 40 |
| Realized Foreign Exchange (Gain) Loss | (61) | - | 168 |
| | 1,036 | 411 | 208 |

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was 16 percent weaker at December 31, 2015 compared with December 31, 2014, resulting in an unrealized loss of $1,097 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 2015 was $78 million (2014 – $83 million).

### Income Tax

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| Current Tax | | | |
| Canada | 586 | 94 | 143 |
| United States | (12) | (2) | 45 |
| **Total Current Tax Expense (Recovery)** | 574 | 92 | 188 |
| **Deferred Tax Expense (Recovery)** | (655) | 359 | 244 |
| | (81) | 451 | 432 |

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

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Earnings Before Income Tax** | 537 | 1,195 | 1,094 |
| Canadian Statutory Rate | 26.1% | 25.2% | 25.2% |
| **Expected Income Tax** | 140 | 301 | 276 |
| Effect of Taxes Resulting From: | | | |
| Foreign Tax Rate Differential | (41) | (43) | 87 |
| Non-Deductible Stock-Based Compensation | 7 | 13 | 10 |
| Non-Taxable Capital Losses | 137 | 74 | 6 |
| Unrecognized Capital Losses Arising from Unrealized Foreign Exchange | 135 | 50 | 25 |
| Adjustments Arising From Prior Year Tax Filings | (55) | (16) | (13) |
| Derecognition (Recognition) of Capital Losses | (149) | (9) | 15 |
| Recognition of U.S. Tax Basis | (415) | - | - |
| Change in Statutory Rate | 161 | - | - |
| Foreign Exchange Gain (Loss) not Included in Net Earnings | - | (13) | 19 |
| Goodwill Impairment | - | 125 | - |
| Other | (1) | (31) | 7 |
| **Total Tax** | (81) | 451 | 432 |
| **Effective Tax Rate** | (15.1)% | 37.7% | 39.5% |

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 2015, current tax increased due to the sale of our royalty interest and mineral fee title lands business and the timing of recognition of partnership income for tax purposes. Of the $574 million of current tax, $391 million is attributed to the sale of the royalty interest and mineral fee title lands business.

We recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of our refining assets. The increase in tax basis was a result of our partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. Additionally, the deferred tax recovery was due to the timing of recognition of partnership income, unrealized risk management losses, reversal of other temporary differences and current year operating losses. This was partially offset by a one-time charge of approximately $161 million from the revaluation of the deferred tax liability due to an increase in the Alberta corporate income tax rate from 10 percent to 12 percent on July 1, 2015.

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 for 2015 differs from the statutory rate due to an increase in tax basis of our U.S. assets, and the recognition of the benefit of capital losses, partially offset by non-deductible unrealized foreign exchange losses and a one-time deferred tax expense arising from the Alberta corporate income tax rate increase.

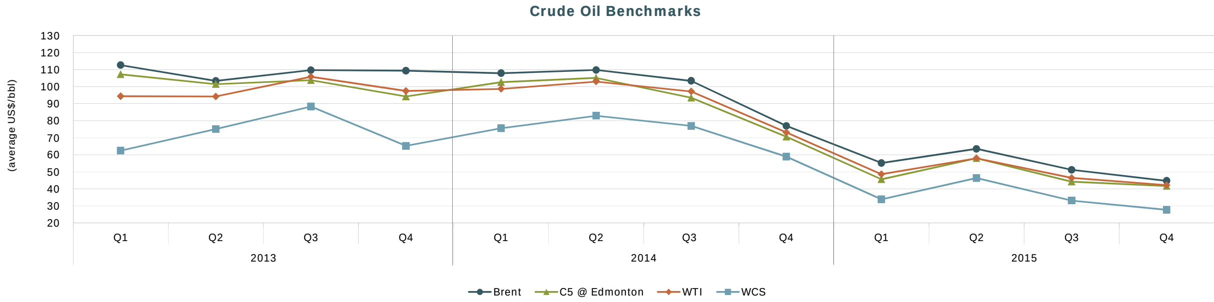
## QUARTERLY RESULTS

Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices. Crude oil production in the fourth quarter of 2015 was six percent higher than in the fourth quarter of 2013, while and natural gas production decreased 18 percent from the fourth quarter of 2013. Our average crude oil and natural gas prices in the fourth quarter of 2015 were 53 percent and 13 percent lower compared with the fourth quarter of 2013.

| ($ millions, except per share amounts or where otherwise indicated) | 2015 Q4 | 2015 Q3 | 2015 Q2 | 2015 Q1 | 2014 Q4 | 2014 Q3 | 2014 Q2 | 2014 Q1 | 2013 Q4 |
|---|---|---|---|---|---|---|---|---|---|
| **Production Volumes** | | | | | | | | | |
| Crude Oil (bbls/d) | 199,556 | 210,422 | 199,954 | 218,020 | 216,177 | 199,089 | 201,688 | 196,854 | 188,743 |
| Natural Gas (MMcf/d) | 424 | 430 | 450 | 462 | 479 | 489 | 507 | 476 | 514 |
| **Refinery Operations** | | | | | | | | | |
| Crude Oil Runs (Mbbls/d) | 405 | 394 | 441 | 439 | 420 | 407 | 466 | 400 | 447 |
| Refined Products (Mbbls/d) | 430 | 414 | 462 | 469 | 442 | 429 | 489 | 420 | 469 |
| **Revenues** | 2,924 | 3,273 | 3,726 | 3,141 | 4,238 | 4,970 | 5,422 | 5,012 | 4,747 |
| **Operating Cash Flow** (1) (2) | 357 | 602 | 932 | 548 | 537 | 1,156 | 1,305 | 1,181 | 976 |
| **Cash Flow** (1) | 275 | 444 | 477 | 495 | 401 | 985 | 1,189 | 904 | 835 |
| Per Share – Diluted | 0.33 | 0.53 | 0.58 | 0.64 | 0.53 | 1.30 | 1.57 | 1.19 | 1.10 |
| **Operating Earnings (Loss)** (1) | (438) | (28) | 151 | (88) | (590) | 372 | 473 | 378 | 212 |
| Per Share – Diluted | (0.53) | (0.03) | 0.18 | (0.11) | (0.78) | 0.49 | 0.62 | 0.50 | 0.28 |
| **Net Earnings (Loss)** | (641) | 1,801 | 126 | (668) | (472) | 354 | 615 | 247 | (58) |
| Per Share – Basic | (0.77) | 2.16 | 0.15 | (0.86) | (0.62) | 0.47 | 0.81 | 0.33 | (0.08) |
| Per Share – Diluted | (0.77) | 2.16 | 0.15 | (0.86) | (0.62) | 0.47 | 0.81 | 0.33 | (0.08) |
| **Capital Investment** (3) | 428 | 400 | 357 | 529 | 786 | 750 | 686 | 829 | 898 |
| **Dividends** | | | | | | | | | |
| Cash Dividends | 132 | 133 | 125 | 138 | 201 | 201 | 201 | 202 | 183 |
| In Shares from Treasury | - | - | 98 | 84 | - | - | - | - | - |
| Per Share | 0.16 | 0.16 | 0.2662 | 0.2662 | 0.2662 | 0.2662 | 0.2662 | 0.2662 | 0.242 |

*(1) Non-GAAP measure defined in this MD&A.*
*(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*
*(3) Includes expenditures on PP&E and E&E assets.*

A substantial downward shift in the commodity price environment occurred late in 2014 and continued throughout 2015. Declining crude oil and refining benchmark prices impacted our fourth quarter financial results. Average Brent and WTI benchmark prices decreased 42 percent in the fourth quarter of 2015 compared with 2014, while the U.S. dollar average WCS price decreased 53 percent.




## Fourth Quarter 2015 Results as Compared with the Fourth Quarter 2014

### *Production Volumes*

Total crude oil production declined eight percent primarily due to expected natural declines, the sale of our royalty interest and mineral fee title lands business, and lower production at Foster Creek. Fourth quarter production was lower compared with 2014. 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 fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

These reductions were partially offset by higher production at Christina Lake and from successful horizontal well performance in southern Alberta. Third-party royalty interest volumes prior to the divestiture in the third quarter were approximately 6,580 barrels of oil equivalent per day.

Natural gas production in the fourth quarter of 2015 decreased 11 percent due to expected natural declines. We continued to focus capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

### *Refinery Operations*

Crude oil runs decreased and refined product output decreased as the planned turnaround at Wood River in 2015 was larger in scale than in 2014. In addition, our Wood River refinery experienced unplanned outages in the fourth quarter of 2015.

### *Revenue*

Revenues decreased $1,314 million or 31 percent primarily due to:

- A decline in Refining and Marketing revenues of $743 million largely due a decrease in refined product prices, consistent with a 37 percent decline in average refined product benchmark prices, and lower refined product output;
- Crude oil and natural gas sales volumes decreasing two percent and 11 percent, respectively;
- Our average crude oil sales price (excluding financial hedging) decreasing 50 percent to $27.63 per barrel; and
- A decline in natural gas sales prices (excluding financial hedging) of 29 percent to $2.78 per Mcf.

The decreases to revenues were partially offset by:

- Crude oil royalties decreasing $68 million; and
- An increase in condensate volumes used for blending with our bitumen and heavy oil production.

### *Operating Cash Flow*

Operating Cash Flow decreased $180 million, or 34 percent, in the three months ended December 31, 2015 compared with 2014. Upstream Operating Cash Flow decreased 54 percent due to lower crude oil and natural gas sales prices, and lower crude oil and natural gas sales volumes, partially offset by higher realized risk management gains and lower royalties due to a decrease in crude oil sales prices.

Refining and Marketing Operating Cash Flow increased by 88 percent to a loss of $40 million. The increase was due to improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, an increase in average market crack spreads and lower refined product inventory impairments, partially offset by lower refined product output and higher operating costs.

### *Cash Flow*

Cash Flow decreased $126 million or 31 percent in the fourth quarter of 2015 compared with 2014, primarily due to lower Operating Cash Flow, as discussed above, and an increase in our general and administrative expenses mainly driven by severance costs related to the previously announced workforce reductions, partially offset by a higher current income tax recovery.

### *Operating Earnings (Loss)*

In the fourth quarter of 2015, our Operating Loss was $438 million compared with a loss of $590 million in the same period in 2014. The improvement was primarily due to no goodwill impairment in 2015 compared with a goodwill impairment of $497 million in 2014 and a higher income tax recovery, partially offset by lower Cash Flow and an increase in DD&A and exploration expense.

### *Net Earnings (Loss)*

In 2015, our Net Loss included unrealized risk management losses of $26 million and non-operating foreign exchange losses of $212 million in addition to the Operating Loss discussed above. In 2014, our Net Loss was smaller due to unrealized risk management gains of $416 million, partially offset by a larger Operating Loss and non-operating foreign exchange losses of $186 million.

### *Capital Investment*

Capital investment in the fourth quarter of 2015 was $428 million, a 46 percent decrease from the same period in 2014 primarily due to lower spending in our Oil Sands and Conventional segments. Capital investment was reduced with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment.

## OIL AND GAS RESERVES AND RESOURCES

We retain independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and coal bed methane ("CBM") reserves and 100 percent of our bitumen contingent and prospective resources producible with established technology.

The sale of our royalty interest and mineral fee title lands business had a minimal effect on our reserves, before royalties. However, our proved and proved plus probable reserves, after royalties, decreased by 27 MMBOE and 39 MMBOE, respectively.

Additional developments in 2015 compared with 2014 include:

- Proved bitumen reserves increasing 11 percent due to Christina Lake proved reserves additions of 234 million barrels from improved reservoir performance and regulatory approval of the Kirby East area expansion converting probable reserves to proved reserves;
- Proved plus probable bitumen reserves remaining constant due to improved reservoir performance at Foster Creek and Christina Lake offsetting production;
- Heavy oil proved reserves and proved plus probable reserves declining 15 percent and 21 percent, respectively. The decrease was due to the deferral of drilling at Pelican Lake, the impact of low crude oil prices and the loss of undeveloped reserves at Elk Point due to poor economics;
- Light and medium oil and NGLs proved reserves decreasing eight percent and proved plus probable reserves decreasing seven percent as production exceeded additions;
- Natural gas proved reserves declining nine percent and proved plus probable reserves decreasing 10 percent as additions and improved performance were more than offset by reductions due to production; and
- Bitumen best estimate economic contingent resources remaining flat at 9.3 billion barrels and bitumen best estimate prospective resources decreasing slightly to 7.4 billion barrels. Factors impacting the results include:
    - Reduced stratigraphic drilling yielding negligible contingent resources revisions; and
    - Minor mapping changes plus small lease expiries slightly reducing prospective resources.

The reserves and resources data that follows is presented as at December 31, 2015 using McDaniel & Associates Consultants Ltd.'s ("McDaniel's") January 1, 2016 forecast prices and inflation. Comparative information as at December 31, 2014 uses McDaniel's January 1, 2015 forecast prices and inflation.

### Reserves

| As at December 31, (before royalties) | Bitumen (MMbbls) | | Heavy Oil (MMbbls) | | Light and Medium Oil & NGLs (MMbbls) | | Natural Gas & CBM (Bcf) | |
|---|---|---|---|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 | **2015** | 2014 |
| Proved | **2,183** | 1,970 | **133** | 156 | **110** | 120 | **721** | 796 |
| Probable | **1,115** | 1,330 | **87** | 123 | **44** | 46 | **232** | 260 |
| **Proved plus Probable** | **3,298** | 3,300 | **220** | 279 | **154** | 166 | **953** | 1,056 |

### Reconciliation of Proved Reserves

| (before royalties) | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2014 | 1,970 | 156 | 120 | 796 |
| Extensions and Improved Recovery | 188 | - | 1 | 8 |
| Technical Revisions | 76 | (10) | 1 | 79 |
| Economic Factors | - | - | (1) | (1) |
| Production [1] | (51) | (13) | (11) | (161) |
| **December 31, 2015** | 2,183 | 133 | 110 | 721 |
| Year Over Year Change | 213 | (23) | (10) | (75) |
| | 11% | (15)% | (8)% | (9)% |

*(1) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.*

### Reconciliation of Probable Reserves

| (before royalties) | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2014 | 1,330 | 123 | 46 | 260 |
| Extensions and Improved Recovery | - | - | 1 | 7 |
| Technical Revisions | (215) | (36) | (4) | (36) |
| Economic Factors | - | - | 1 | 1 |
| **December 31, 2015** | 1,115 | 87 | 44 | 232 |
| Year Over Year Change | (215) | (36) | (2) | (28) |
| | (16)% | (29)% | (4)% | (11)% |

### Economic Contingent Resources and Prospective Resources

| As at December 31, (billions of barrels, before royalties) | Bitumen 2015 | Bitumen 2014 |
|---|---|---|
| **Economic Contingent Resources** [1] | | |
| Best Estimate | 9.3 | 9.3 |
| **Prospective Resources** [1] [2] | | |
| Best Estimate | 7.4 | 7.5 |

*(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.*
*(2) There is uncertainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.*

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), and material risks and uncertainties associated with estimates of reserves and contingent and prospective resources is contained in our AIF for the year ended December 31, 2015. Further information with respect to contingent and prospective resources including project descriptions, significant factors relevant to the resource estimates, and contingencies which prevent the classification of contingent resources as reserves is contained in our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2015 ("Resources Statement"). Both our AIF and Resources Statement are available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions) | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Net Cash From (Used In)** | | | |
| Operating Activities | 1,474 | 3,526 | 3,539 |
| Investing Activities | 888 | (4,350) | (1,519) |
| **Net Cash Provided (Used) Before Financing Activities** | 2,362 | (824) | 2,020 |
| Financing Activities | 894 | (797) | (726) |
| Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency | (34) | 52 | (2) |
| **Increase (Decrease) in Cash and Cash Equivalents** | 3,222 | (1,569) | 1,292 |

| As at December 31, | 2015 | 2014 | 2013 |
|---|---|---|---|
| **Cash and Cash Equivalents** | 4,105 | 883 | 2,452 |
| **Committed and Undrawn Credit Facilities** | 4,000 | 3,000 | 3,000 |

### Operating Activities

Cash from operating activities decreased in 2015 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 $4,337 million at December 31, 2015 compared with $772 million at December 31, 2014. Working capital increased due to cash proceeds received on the sale of our royalty interest and mineral fee title lands business in July of 2015 and the common share issuance in the first quarter of 2015.

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

### Investing Activities

Cash from investing activities in 2015 was primarily due to the divestiture of our royalty interest and mineral fee title lands business in 2015. In 2014, cash used by investing activities related to the repayment of the US$1.4 billion Partnership Contribution Payable. Lower capital expenditures in 2015 also contributed to the increase in cash from investing activities.

### Financing Activities

Cash provided by financing activities increased in 2015 primarily due to net proceeds from our common share issuance and cash savings from our DRIP. We issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion in the first quarter of 2015. We plan to use the net proceeds to partially fund our capital expenditure program for 2016 and for general corporate purposes.

In 2015, we paid dividends of $0.8524 per share or $710 million, of which $528 million was paid in cash and $182 million was reinvested in common shares through our DRIP (2014 – $1.0648 per share or $805 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Our long-term debt at December 31, 2015 was $6,525 million (December 31, 2014 – $5,458 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 $1,067 million increase in long-term debt is due to weakening of the Canadian dollar relative to the U.S. dollar.

As at December 31, 2015, 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 December 31, 2015:

| ($ millions) | Amount | Term |
|---|---|---|
| Cash and Cash Equivalents | **4,105** | **Not applicable** |
| Committed Credit Facility | **1,000** | **November 2017** |
| Committed Credit Facility | **3,000** | **November 2019** |
| U.S. Base Shelf Prospectus [(1)] | **US$2,000** | **July 2016** |
| Canadian Base Shelf Prospectus [(1)] | **1,500** | **July 2016** |

*(1) Availability is subject to market conditions.*

#### *Committed Credit Facility*

In 2015, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at December 31, 2015, we had $4.0 billion available on our committed credit facility.

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

#### *U.S. and Canadian Base Shelf Prospectuses*

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue.

On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue.

As at December 31, 2015, no notes were issued under the existing U.S. or Canadian base shelf prospectuses.

It is our intention to file a new prospectus prior to the maturity of the existing 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.

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 higher debt balances from the weakening of the Canadian dollar relative to the U.S. dollar were offset by the increase in Shareholders' Equity as a result of the common share issuance. Debt to Adjusted EBITDA increased from higher debt balances due to foreign exchange and lower Adjusted EBITDA primarily due to a decline in Cash Flow as a result of low commodity prices.

Debt to Capitalization and Net Debt to Capitalization are calculated as follows:

| As at December 31, | **2015** | 2014 | 2013 |
|---|---|---|---|
| Debt | **6,525** | 5,458 | 4,997 |
| Shareholders' Equity | **12,391** | 10,186 | 9,946 |
| Capitalization | **18,916** | 15,644 | 14,943 |
| **Debt to Capitalization** | **34%** | 35% | 33% |
| Net Debt (1) | **2,420** | 4,575 | 4,070 |
| Shareholders' Equity | **12,391** | 10,186 | 9,946 |
| Capitalization | **14,811** | 14,761 | 14,016 |
| **Net Debt to Capitalization** | **16%** | 31% | 29% |

*(1) Net Debt is defined as Debt and the current and long-term portions of the Partnership Contribution Payable, net of cash and cash equivalents.*

The following is a reconciliation of Adjusted EBITDA, and the calculations of Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA:

| As at December 31, | **2015** | 2014 | 2013 |
|---|---|---|---|
| **Debt** | **6,525** | 5,458 | 4,997 |
| **Net Debt (1)** | **2,420** | 4,575 | 4,070 |
| **Adjusted EBITDA** | | | |
| Net Earnings | **618** | 744 | 662 |
| Add (Deduct): | | | |
| Finance Costs | **482** | 445 | 529 |
| Interest Income | **(28)** | (33) | (96) |
| Income Tax Expense | **(81)** | 451 | 432 |
| DD&A | **2,114** | 1,946 | 1,833 |
| Goodwill Impairment | **-** | 497 | - |
| E&E Impairment | **138** | 86 | 50 |
| Unrealized (Gain) Loss on Risk Management | **195** | (596) | 415 |
| Foreign Exchange (Gain) Loss, Net | **1,036** | 411 | 208 |
| (Gain) Loss on Divestiture of Assets | **(2,392)** | (156) | 1 |
| Other (Income) Loss, Net | **2** | (4) | 2 |
| | **2,084** | 3,791 | 4,036 |
| **Debt to Adjusted EBITDA** | **3.1x** | 1.4x | 1.2x |
| **Net Debt to Adjusted EBITDA** | **1.2x** | 1.2x | 1.0x |

*(1) Net Debt is defined as Debt and the current and long-term portions of the Partnership Contribution Payable, net of cash and cash equivalents.*

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 at December 31, 2015, there were approximately 833 million common shares outstanding (December 31, 2014 – 757 million common shares). Cenovus issued 76.2 million common shares in 2015, including 8.7 million shares issued under the DRIP and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

The DRIP permits shareholders to reinvest their dividends into additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. In the first half of 2015, participants in our DRIP were issued shares from treasury at a three percent discount to the average market price, as defined in the DRIP; this resulted in cash savings of $177 million. For the second half of the year, common shares acquired by the DRIP were purchased on the open market. Refer to cenovus.com for more details.

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 27 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

| As at January 31, 2016 | Units Outstanding (thousands) | Units Exercisable (thousands) |
|---|---|---|
| Common Shares | **833,290** | **N/A** |
| Stock Options | **43,660** | **25,892** |
| Other Stock-Based Compensation Plans | **10,257** | **1,488** |

### 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.

The below contractual obligations have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise:

| | Expected Payment Date | | | | | | |
|---|---|---|---|---|---|---|---|
| ($ millions) | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter | Total |
| **Operating** | | | | | | | |
| Transportation and Storage [(1)] | 702 | 715 | 780 | 774 | 901 | 23,537 | **27,409** |
| Operating Leases (Building Leases) | 116 | 120 | 156 | 153 | 151 | 2,647 | **3,343** |
| Product Purchases | 84 | 3 | - | - | - | - | **87** |
| Other Long-term Commitments | 45 | 31 | 24 | 26 | 15 | 125 | **266** |
| Interest on Long-term Debt | 349 | 349 | 349 | 349 | 247 | 4,193 | **5,836** |
| Decommissioning Liabilities | 34 | 28 | 28 | 30 | 36 | 6,509 | **6,665** |
| **Total Operating** | 1,330 | 1,246 | 1,337 | 1,332 | 1,350 | 37,011 | **43,606** |
| **Investing** | | | | | | | |
| Capital Commitments | 61 | 14 | 4 | - | - | - | **79** |
| **Total Investing** | 61 | 14 | 4 | - | - | - | **79** |
| **Financing** | | | | | | | |
| Long-term Debt (principal only) | - | - | - | 1,799 | - | 4,775 | **6,574** |
| **Total Financing** | - | - | - | 1,799 | - | 4,775 | **6,574** |
| **Total Payments [(2)]** | 1,391 | 1,260 | 1,341 | 3,131 | 1,350 | 41,786 | **50,259** |
| Fixed Price Product Sales | 55 | 3 | - | - | - | - | **58** |

*(1) Certain transportation commitments included are subject to regulatory approval.*
*(2) Contracts on behalf of FCCL Partnership ("FCCL") and WRB are reflected at our 50 percent interest.*

As operator of Foster Creek, Christina Lake and Narrows Lake, we are responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. 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.

Commitments for various firm pipeline transportation agreements were $27 billion, consistent with 2014. Reduced obligations from changes to TransCanada's proposed Energy East pipeline were offset by increases to our U.S. dollar commitments due to the weakening of the Canadian dollar relative to the U.S. dollar, and higher costs and tolls on existing commitments.

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our purchase of a crude-by-rail terminal and exporting crude oil from the U.S. Gulf Coast. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, assessing options to maximize the value of our crude oil by offering a wider range of products, including existing dilbit blends, under-blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

As at December 31, 2015, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 29 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 11 Bcf of natural gas, at a weighted average price of $4.94 per Mcf.

In the normal course of business, we also lease office space for staff who support field operations and for corporate purposes.

### 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.

### Related Party Transactions

Cenovus did not enter into any related party transactions during the years ended December 31, 2015 or 2014, except for our key management compensation. A summary of key management compensation can be found in the notes to the Consolidated Financial Statements.

## RISK MANAGEMENT

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. Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus.

### Risk Governance

The ERM Policy, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Practices, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in its *ISO 31000 – Risk Management Principles and Guidelines*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through quarterly updates.


### Risk Assessment

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized risk assessment tools.

Using a Risk Matrix, each risk is classified on a continuum ranging from "Low" to "Extreme". Risks are first evaluated on an inherent basis, without considering the presence of controls or mitigating measures. Risks are then re-evaluated based on their residual risk ranking, reflecting the exposure that remains after implemented mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking. There are prescribed actions for escalating and communicating risk to the right decision makers.

### Significant Risk Factors

The following discussion describes the financial, operations and regulatory risks relating to Cenovus and our operations. A description of the risk factors and uncertainties can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2015.

#### *Financial Risk*

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations of commodity prices, interest rates and foreign exchange rates.

### Commodity Prices

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.

Crude oil and natural gas prices are impacted by a number of factors including global and regional supply and demand and economic conditions, the actions of OPEC, government regulation, political stability, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility. Changing prices will affect the revenues generated by the sale of our production. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

Commodity prices began to decline in the fourth quarter of 2014 and have remained low, resulting in an impairment to the carrying value of some of our assets. If crude oil and natural gas prices continue to decline significantly and remain at low levels for an extended period of time, future capital spending could be reduced causing projects to be impaired, delayed or cancelled, and production could be curtailed or suspended, among other impacts.

Refined product prices are affected by several factors including global supply and demand for refined products, weather conditions, and planned and unplanned refinery maintenance, all of which are beyond our control and can result in a high degree of price volatility. The financial performance of our refining operations is also impacted by margin volatility due to fluctuations in the supply and demand for refined products, crude oil costs and seasonal factors when production changes to match seasonal demand.

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 3 and 32 to the Consolidated Financial Statements.

*Impact of Financial Risk Management Activities*

| | 2015 | | | 2014 | | |
|---|---|---|---|---|---|---|
| ($ millions) | **Realized** | **Unrealized** | **Total** | Realized | Unrealized | Total |
| Crude Oil | **(571)** | **123** | **(448)** | (37) | (536) | (573) |
| Natural Gas | **(59)** | **55** | **(4)** | (7) | (55) | (62) |
| Refining | **(36)** | **10** | **(26)** | (26) | (11) | (37) |
| Power | **10** | **5** | **15** | 4 | 6 | 10 |
| Interest Rate | **-** | **2** | **2** | - | - | - |
| **(Gain) Loss on Risk Management** | **(656)** | **195** | **(461)** | (66) | (596) | (662) |
| Income Tax Expense (Recovery) | **175** | **(54)** | **121** | 20 | 152 | 172 |
| **(Gain) Loss on Risk Management, After Tax** | **(481)** | **141** | **(340)** | (46) | (444) | (490) |

In 2015, we recorded realized gains on crude oil and natural gas risk management activities, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions partially offset by changes in market prices.

*Commodity Price Sensitivities – Risk Management Positions*

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) for the year on open risk management positions as at December 31, 2015 as follows:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10 per bbl Applied to Brent and WTI Hedges | **(243)** | **245** |
| Crude Oil Differential Price | ± US$5 per bbl Applied to Differential Hedges Tied to Production | **80** | **(80)** |
| Condensate Commodity Price | ± US$10 per bbl Applied to Condensate Hedges | **23** | **(23)** |
| Power Commodity Price | ± $25 per MWHr Applied to Power Hedge | **19** | **(19)** |
| Interest Rate Swaps | ± 50 Basis Points | **38** | **(46)** |

*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're 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.

#### Liquidity

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due or be unable to liquidate assets in a timely manner at a reasonable price. In declining economic times, such as the low commodity price environment in which we are currently operating, or due to unforeseen events, our liquidity risk could become heightened.

Liquidity risk is further impacted by the amount and timing of financial and operating commitments, future capital expenditures, debt repayments as well as available sources of liquidity, which may be impacted by our credit ratings. If we were unable to meet our financial obligations as they became due or be unable to liquidate assets in a timely manner at a reasonable price, this could have a material adverse effect on our financial condition, results of operations, cash flows, access to capital, ability to comply with various financial and operating covenants, credit ratings and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including, but not limited to, cash and cash equivalents, cash from operating activities, undrawn credit facilities and availability under our shelf prospectuses. At December 31, 2015, we had cash and cash equivalents of $4.1 billion. No amounts were drawn on our $4.0 billion committed credit facility. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$2.0 billion in unused capacity under our U.S. base shelf prospectus, the availability of which is dependent on market conditions and our credit ratings. We intend to file a new prospectus prior to the maturity of the existing prospectuses.

#### Foreign Exchange Rates

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. 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. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

### *Operational Risk*

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. To partially mitigate our risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System ("COMS") to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition to leveraging COMS, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

#### Market Access and Transportation Restrictions

Cenovus's production is transported through pipelines and by rail and its refineries are reliant on pipelines to receive feedstock. Disruptions in, or restricted availability of pipeline service or rail shipments, could adversely affect our crude oil and natural gas sales, projected production growth, refining operations and cash flows. Insufficient transportation capacity for our production will impact our ability to efficiently access end markets. This may negatively impact our financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades of crude oil, and in extreme situations, production curtailment.

#### Operational Outages and Major Environmental or Safety Incidents

Our crude oil and natural gas production activities are subject to inherent operational risks such as encountering unexpected formations or pressures, blowouts, equipment failures and other accidents, interdependence of component systems, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Our refining and marketing activities are subject to risks including slowdowns due to equipment failure or transportation disruptions, weather, fires, explosions, railcar incidents or derailments, unavailability of feedstock, and poor price and quality of feedstock. Cenovus's operations could also be interrupted by natural disasters or other events beyond our control.

Failure to manage these risks effectively could result in potential fatalities, serious injury, asset damage or environmental impacts, any of which could have a material adverse effect on our reputation, financial condition, results of operations and cash flows. Cenovus does not insure against all potential occurrences and disruptions and our insurance may be insufficient to cover any such occurrences or disruptions.

#### Project Execution

There are risks associated with the execution and operations of our upstream and refining growth and development projects. Successful project execution will be highly dependent upon the availability and cost of materials, equipment and skilled labour, our ability to finance growth and general economic conditions. Project execution will also be impacted by our ability to obtain the necessary environmental and regulatory approvals, and the effect of changing government regulations and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could also cause delays in achieving targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

#### Cost Management

Our operating costs could escalate and become uncompetitive due to labour costs, equipment limitations, commodity prices, higher steam-to-oil ratios in our oil sands operations, additional government or environmental regulations and general inflationary pressures. Operating costs associated with our crude oil production are largely fixed in the short-term and, as a result, are largely dependent on levels of production. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

#### Reserves Replacement

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves.

#### Leadership and Talent

Our success in executing our business strategy is dependent upon Management and their leadership capabilities, as well as, the quality and competency of our employees. If we fail to retain critical talent or are unsuccessful in attracting and retaining new talent, with the necessary leadership traits, skills and technical competencies, it could have a materially adverse effect on Cenovus's results of operations, pace of growth and financial condition.

### *Regulatory Risk*

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for a crude oil or natural gas development project. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as result in compliance costs, adversely impacting our financial condition, results of operations and cash flows.

#### Regulatory Approvals

Our operations are subject to regulation and intervention by governments in areas such as energy policies, environmental and safety policies, land tenure, taxes, royalties, government fees, the export of crude oil, natural gas and other products, production rates, expropriation or cancellation of contract rights, acquisition of exploration and production rights, and control over the development and abandonment of fields. Changes to government regulation could impact Cenovus's existing and planned projects or increase capital investment or operating expenses, adversely impacting our financial condition, results of operations and cash flows.

#### Royalty Regimes

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 report on January 29, 2015. The report recommends no changes to existing oil sands royalty rates but recommended further government-industry consultation on administrative aspects of the oil sands royalty regime. The royalty review report recommended a modernization of Alberta's conventional oil and gas royalty regime but did not provide details. The changes proposed to conventional oil and gas royalties will require further consultation between industry and government to fully understand their impacts. These changes to the Alberta provincial royalty structure could have a significant impact on Cenovus's financial condition, results of operations and cash flows. An increase in the royalty rates applicable in one or both provinces could make, in the respective province, future capital expenditures or existing operations uneconomic.

#### Environmental Regulations

Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances in the environment. They also impose restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations can require significant expenditures, including clean-up costs and damages arising from contaminated properties. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and environmental protection orders. The costs of complying with environmental regulations in the future may have a material adverse effect on our financial condition, results of operations and cash flows. Non-compliance with environmental regulations could have an adverse impact on Cenovus's reputation. There is also a risk that Cenovus could face litigation initiated by third parties relating to climate change or other environmental regulations.

*Species at Risk Act*

The Canadian federal legislation, Species at Risk Act, and provincial counterparts regarding threatened or endangered species may influence development in areas identified as critical habitat for species of concern (e.g. woodland caribou). In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may limit our pace and amount of development and, in some cases, may result in an inability to operate in affected areas.

*Climate Change*

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. In November, 2015, the Government of Alberta announced its climate leadership plan (the "CLP") highlighting four key strategies that the government will implement to address climate change: (1) the complete phase-out of coal-fired sources of electricity by 2030; (2) an Alberta economy-wide price on GHG emissions of $30/tonne; (3) capping oil sands emissions to a province-wide total of 100 megatonnes per year, with certain exceptions for cogeneration power sources and new upgrading capacity; and (4) reducing methane emissions from oil and gas activities by 45 percent by 2025.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes per year or more of GHG. 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 starting in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The SGER amendments have increased the price for such credits from $15/tonne to $20/tonne for 2016 and $30/tonne beginning in 2017.

If comprehensive GHG regulation is enacted in Alberta or any jurisdiction in which we operate, including legislation to implement the CLP, and as a result of the amendments to the SGER, we may incur increased compliance costs, loss of markets, permitting delays, 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.

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.

*Water Licenses*

To operate our SAGD facilities we rely on water, which is obtained under licenses issued through the Alberta Water Act. Currently, we are not required to pay for the water we use under these licenses. If a change under these licenses reduces the amount of water available for our use, our production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses.

*Alberta's Land-Use Framework*

The Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), which identifies legally binding management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation. This may have a material adverse effect on our financial condition, results of operations and cash flows. Additional regional plans are in the process of being developed by the Government of Alberta and no assurances can be given that such plans, if approved and implemented, will not materially impact our operations or future operations.

## CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

### Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our Consolidated Financial Statements.

#### *Joint Arrangements*

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations and our share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements*", we considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

#### *Exploration and Evaluation Assets*

The application of Cenovus's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and Cenovus's internal approval process.

#### *Identification of CGUs*

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of Cenovus's upstream, refining, crude-by-rail and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses.

### 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. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

### *Crude Oil and Natural Gas Reserves*

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

### *Impairment of Assets*

Impairment calculations require the use of estimates and assumptions, which are subject to change as new information becomes available. For our upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the our refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions, and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Refer to the Outlook section of this MD&A for more details on future commodity prices and to the reportable segments section of this MD&A for more details on impairments.

As at December 31, 2015, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal. Key assumptions in the determination of cash flows from reserves include crude oil and natural gas prices, and the discount rate. All reserves have been evaluated at December 31, 2015 by IQREs.

#### Crude Oil and Natural Gas Prices

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

| | 2016 | 2017 | 2018 | 2019 | 2020 | Average Annual % Change to 2026 |
|---|---|---|---|---|---|---|
| WTI (US$/barrel) | 45.00 | 53.60 | 62.40 | 69.00 | 73.10 | 3.8% |
| WCS ($/barrel) | 46.40 | 54.40 | 59.70 | 66.30 | 68.20 | 3.9% |
| AECO ($/Mcf) (1) | 2.70 | 3.20 | 3.55 | 3.85 | 3.95 | 4.0% |

*(1) 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 IQREs 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.

### *Decommissioning Costs*

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgement to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. Refer to Note 22 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

### *Income Tax Provisions*

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods. Refer to the Corporate and Eliminations section of this MD&A for more details on changes to estimates related to income taxes.

### Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during 2015.

### Future Accounting Pronouncements

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2016 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2015. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

#### *Leases*

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

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 16 on the Consolidated Financial Statements.

#### *Revenue Recognition*

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

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. Early adoption is permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements.

#### *Financial Instruments*

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. We do not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

## CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2015. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting.

Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2015.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2015. There have been no changes to ICFR during the year ended December 31, 2015 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.

## CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and integrating our corporate responsibility principles in the way we conduct our business. Our Corporate Responsibility ("CR") policy guides our activities in the areas of: Leadership; Corporate Governance and Business Practices; People; Environmental Performance; Stakeholder and Aboriginal Engagement; and Community Involvement and Investment.

We published our 2014 CR report in June 2015, detailing our efforts to accelerate our environmental performance, protect the health and safety of our staff, invest in and engage with the communities where we operate and maintain the highest standards of corporate governance. Our CR report also lists external recognition we received for our commitment to corporate responsibility and our efforts to balance economic, governance, social and environmental performance. Our CR policy and CR report are available on our website at cenovus.com.

## OUTLOOK

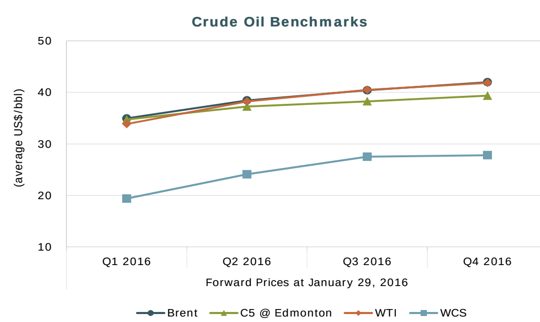
We expect 2016 will be another challenging year for our industry. Maintaining our financial resilience remains a top priority. Our revised 2016 guidance reflects reduced capital spending plans, consistent with our expectation that commodity prices will continue to be low for a prolonged period of time.

The following outlook commentary is focused on the next 12 months.

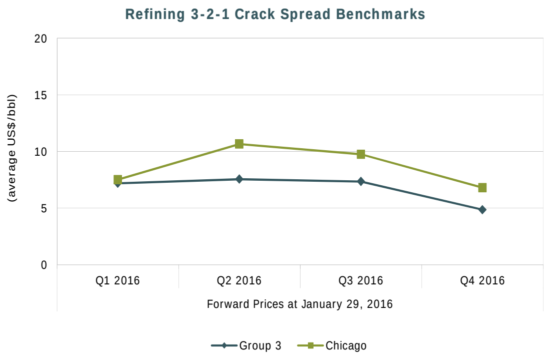
### Commodity Prices Underlying our Financial Results

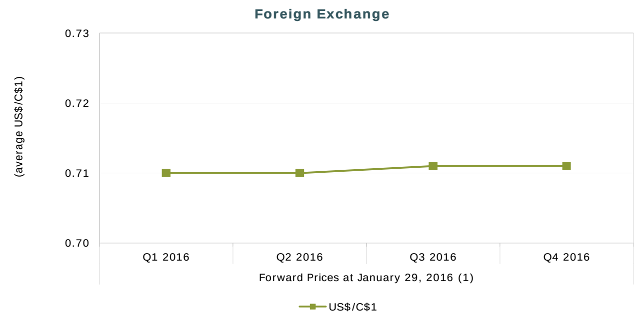
Our crude oil pricing outlook is influenced by the following:

- 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 of the global economy. Overall, we expect crude oil price volatility and a modest price improvement in 2016. Slower global supply growth, 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 anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth 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.




  We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production, which will depress crude oil prices, and that economic uncertainty in China may slow emerging market demand;
- We expect the Brent-WTI differential to remain narrow now that the U.S. has lifted restrictions on 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 and further expansions on existing pipeline systems.




(1) *Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.*

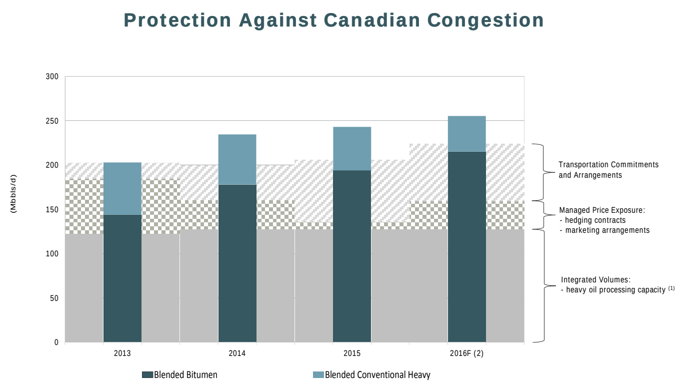
Refining crack spreads in 2016, as forecasted at January 29, 2016, are expected to strengthen late in the second quarter due to higher seasonal demand for refined products and then decline in the second half of the year.

Natural gas production is anticipated to increase marginally in 2016 due to low levels of drilling activity. However, warmer weather is expected to reduce residential and commercial demand, while coal-to-gas substitution in the power sector is expected to continue. As a result, natural gas prices are anticipated to remain weak through the first half of 2016.

The average foreign exchange forward price expected over the next 12 months is US$0.711/C$. We expect that the Canadian dollar, compared with the U.S. dollar, will remain relatively weak in the near term due to weak commodity prices and Canadian economic uncertainty. Overall, a weak Canadian dollar should 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.




(1) *Expected gross production capacity.*
(2) *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).*

## Key Priorities for 2016

### *Maintain Financial Resilience*

Maintaining our financial resilience continues to be a top priority. At December 31, 2015, we had $4.1 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. We also have Canadian and U.S. base shelf prospectuses, the availability of which is dependent on market conditions and our credit ratings. 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, as we anticipate commodity prices to remain low in the upcoming year.

### *Attack Cost Structures*

We will continue to focus on reducing our cost structure. In 2015, we captured savings of approximately $540 million, relative to our budget, from capital, operating and general and administrative cost reductions. We believe approximately 60 percent of these cost savings are sustainable over the long term and were reflected in our original 2016 budget.

We believe we are positioned to achieve additional sustainable cost reductions going forward. 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 budget announced in December 2015. We are targeting $100 million to $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.

## ADVISORY

### Oil and Gas Information

The estimates of reserves and resources data and related information were prepared effective December 31, 2015 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2016 price forecast. For additional information about our reserves, resources and other oil and gas information, see “Reserves Data and Other Oil and Gas Information” in our AIF for the year ended December 31, 2015 and our Resources Statement.

Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The estimate of contingent resources has not been adjusted for risk based on the chance of development.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus’s case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2015 reserves evaluation, which comply with NI 51-101 requirements.

Prospective resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources were estimated for individual projects and then aggregated for disclosure purposes.

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

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2015, and our Resources Statement, both available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

## Forward-looking Information

This document contains certain forward-looking statements and other information (collectively “forward-looking information”) about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as “anticipate”, “believe”, “expect”, "estimate", “plan”, “forecast” or “F”, “future”, “target”, "position", “project”, “capacity”, “could”, “should”, “focus”, “goal”, “outlook”, "proposed", “potential”, “may”, "schedule", "on track", “strategy”, “forward”, “opportunity” or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules; projected future value; projections for 2016 and future years; forecast operating and financial results; targets for our Debt to Capitalization and Debt to EBITDA ratios; planned capital expenditures, including the timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves and resources; broadening market access; expected capacities, including for projects, transportation and refining; improving cost structures, forecast cost savings and sustainability thereof; dividend plans and strategy anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and expected impact to Cenovus; future use and development of technology, including expected effects on our environmental impact; and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2016 guidance, as updated on February 11, 2016, 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 our actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of our 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; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated business; reliability of our assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; 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 our business; the timing and the costs of well and pipeline construction; our 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 our ability to attract and retain, critical talent; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the period ended December 31, 2015, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

## ABBREVIATIONS

The following abbreviations 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. |