MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED MARCH 31, 2017

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", or "Cenovus", mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated April 25, 2017, should be read in conjunction with our March 31, 2017 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2016 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2016 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 25, 2017, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. The information in this MD&A, as it relates to our operations for the three months ended March 31, 2017, does not reflect the closing of the Acquisition (as defined in this MD&A). See the Transformational Acquisition section of this MD&A for more details. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

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

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

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On March 31, 2017, we had an enterprise value of approximately $16 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in western Canada. We conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production for the three months ended March 31, 2017 was approximately 234,900 barrels per day and our average natural gas production was 363 MMcf per day. The refining operations processed an average of 406,000 gross barrels per day of crude oil feedstock into an average of 433,000 gross barrels per day of refined products.

Transformational Acquisition

On March 29, 2017, we announced a transformational acquisition of approximately $17.7 billion with ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") to acquire ConocoPhillips' 50 percent interest in FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets in Alberta and British Columbia (the "Acquisition").

This Acquisition will provide us with full control over our oil sands operations, will double our oil sands production, and almost double our proved bitumen reserves. The transaction will give us an additional growth platform with more than three million net acres of undeveloped land, exploration and production assets, and related infrastructure in Alberta and British Columbia (collectively the "Deep Basin Assets"). The Deep Basin Assets are expected to provide complementary short-cycle development opportunities with high return potential.

Concurrent with the announcement of the Acquisition, we commenced marketing for sale certain non-core properties to help fund the Acquisition. We plan to divest of our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican Lake region, and our Suffield crude oil and natural gas assets.

The Acquisition has an effective date of January 1, 2017 and is expected to close in the second quarter of 2017, subject to customary closing conditions and regulatory approvals.

Our Operations

Oil Sands

Our operations include steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta, namely Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects, located in the Athabasca region of northeastern Alberta, are operated by Cenovus and jointly owned (50 percent interest) with ConocoPhillips, an unrelated U.S. public company. Our 100 percent-owned emerging project at Telephone Lake is located within the Borealis region of northeastern Alberta.

	Three Months Ended March 31, 2017	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Margin	**249**	**1**
Capital Investment	**169**	**3**
Operating Margin Net of Related Capital Investment	**80**	**(2)**

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 flows to help fund our growth opportunities.

	Three Months Ended March 31, 2017	
($ millions)	**Crude Oil (1)**	**Natural Gas**
Operating Margin	**100**	**44**
Capital Investment	**85**	**3**
Operating Margin Net of Related Capital Investment	**15**	**41**

(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 (50 percent interest) and operated by Phillips 66, an unrelated U.S. public company. The gross crude oil capacity at the Wood River and Borger refineries (the "Refineries") is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. The refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	**Three Months Ended March 31, 2017**
Operating Margin	**53**
Capital Investment	**46**
Operating Margin Net of Related Capital Investment	**7**

TRANSFORMATIONAL ACQUISITION

On March 29, 2017, we announced a transformational acquisition of approximately $17.7 billion to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets in Alberta and British Columbia (the "Deep Basin Assets"). The Acquisition will provide us with full control over our oil sands operations, will double our oil sands production, and almost double our proved bitumen reserves. The Deep Basin Assets will give us an additional growth platform with more than three million net acres of undeveloped land, exploration and production assets, and related infrastructure in Alberta and British Columbia. The Deep Basin Assets are expected to provide complementary short-cycle development opportunities with high return potential.

Total consideration for the Acquisition, as announced on March 29, 2017, includes US$10.6 billion in cash and 208 million Cenovus common shares (the "Consideration Shares"). To finance the cash portion of the purchase price, we:

- Closed a Bought-Deal Common Share Offering on April 6, 2017 for 187.5 million common shares at a price of $16.00 per share, raising gross proceeds of $3.0 billion;
- Completed an offering in the U.S. for US$2.9 billion of senior unsecured notes – US$1.2 billion 4.25 percent senior unsecured notes due April 2027, US$700 million 5.25 percent senior unsecured notes due June 2037, and US$1.0 billion 5.40 percent senior unsecured notes due June 2047. The funds from this offering (the "Note Offering") were placed into escrow subject to closing of the Acquisition;
- Intend to borrow $3.6 billion under a committed asset sale bridge credit facility ("Bridge Facility"); and
- Anticipate the remainder of the purchase price will be funded by our existing committed credit facility and cash on hand.

The committed asset sale bridge credit facility consists of three tranches which mature 12 months, 18 months and 24 months, respectively, following the Acquisition closing date. We expect to repay the committed Bridge Facility through the sale of certain assets. Concurrent with the announcement of the Acquisition, we commenced marketing for sale certain non-core properties to help fund the Acquisition. We plan to divest of our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican Lake region, and our Suffield crude oil and natural gas assets.

As part of the Acquisition, Cenovus has agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date for quarters in which the average Western Canadian Select ("WCS") crude oil price exceeds $52.00 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52.00 per barrel. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake which may reduce the amount of a contingent payment. There are no maximum payment terms. The terms of the contingent payment agreement allow Cenovus to retain 80 percent to 85 percent of the WCS prices above $52.00 per barrel, based on current gross production capacity at Foster Creek and Christina Lake. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

The Acquisition has an effective date of January 1, 2017 and is expected to close in the second quarter of 2017, subject to customary closing conditions and regulatory approvals. As at March 31, 2017, Cenovus has paid a deposit of US$129.5 million, which will be applied against the Acquisition purchase price at the date of closing. We anticipate the majority of the purchase price will be allocated to acquired Property, Plant and Equipment ("PP&E"), Exploration and Evaluation ("E&E") assets, and goodwill.

Our material change report dated April 5, 2017, available on SEDAR and EDGAR, included forecast information outlining the expected impacts that the Acquisition will have on our business. If forecast production from the acquired assets pertained to the full year of 2017, Cenovus would expect the Acquisition to increase Adjusted Funds Flow by 92 percent before the impact of expected dispositions, reduce upstream operating costs per BOE by seven percent and reduce general and administrative expenses per BOE by 24 percent. In addition, Cenovus would expect the acquired assets to generate Operating Margin of $1.8 billion for 2017 (assumes a flat US$50 per barrel WTI price throughout the year).

Before giving effect to the Acquisition, Cenovus, through a wholly owned subsidiary, was the managing partner and jointly owned 50 percent of FCCL. FCCL met the definition of a joint operation under IFRS 11, "*Joint Arrangements*" and as such we recognized our share of the assets, liabilities, revenues and expenses in our consolidated results before the business combination. Upon completion of the Acquisition, we will control FCCL, as defined under IFRS 10, "*Consolidated Financial Statements*" and accordingly FCCL will be consolidated. Upon closing, the Acquisition will be accounted for using the acquisition method pursuant to IFRS 3, "*Business Combinations*" ("IFRS 3"). As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings. At the closing date of the Acquisition, Cenovus expects to record a non-cash revaluation gain on the re-measurement to fair value of its existing interest in FCCL.

Additional information on the Acquisition is available in our news release, dated March 29, 2017 available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com, and in our material change report dated April 5, 2017 available on SEDAR and EDGAR. The information in this MD&A, as it relates to our operations for the three months ended March 31, 2017, does not reflect closing of the Acquisition.

QUARTERLY HIGHLIGHTS

In the first quarter of 2017, the West Texas Intermediate ("WTI") benchmark price fluctuated between US$47 per barrel and US$54 per barrel, a significant improvement from a 13-year low of US$26 per barrel in the first quarter of 2016. As a result, our average crude oil sales price almost tripled from the first quarter of 2016. The higher crude oil sales price, combined with a 32 percent increase in our Oil Sands production, contributed to a $329 million increase in Net Earnings in 2017. Our companywide Netback of $19.11 per BOE in the first quarter, before realized risk management activities, was our highest quarterly Netback since the second quarter of 2015. We continued to focus on lowering our cost structure and maintaining our financial resilience, while delivering safe and reliable operations.

In the first quarter, we:

- Announced a transformational Acquisition;
- Increased total crude oil production by 19 percent from the first quarter of 2016, primarily due to incremental production volumes from Foster Creek phase G and Christina Lake phase F, both of which started-up in the second half of 2016;
- Almost doubled our combined Oil Sands and Conventional revenues compared with the same period in 2016, primarily related to higher crude oil sales prices;
- Decreased our per-unit crude oil operating costs by $0.81 per barrel, or seven percent, compared with the first quarter of 2016;
- Achieved Cash From Operating Activities and Adjusted Funds Flow of $328 million and $323 million, respectively, an increase from the first quarter of 2016 of $146 million and $297 million, respectively;
- Recorded Net Earnings of $211 million compared with a Net Loss of $118 million in 2016; and
- Invested $313 million in capital spending, a three percent decline from the first quarter of 2016. We will continue to allocate capital in a disciplined manner, closely managing the pace at which we choose to invest.

OPERATING RESULTS

Our upstream assets continued to perform well in the first quarter of 2017. Total crude oil production increased as the planned ramp up of our expansion phases was partially offset by the expected lower production from our Conventional properties.

Crude Oil Production Volumes

	Three Months Ended March 31,		
(barrels per day)	**2017**	**Percent Change**	2016
Oil Sands			
Foster Creek	**80,866**	**33%**	60,882
Christina Lake	**100,635**	**31%**	77,093
	181,501	**32%**	137,975
Conventional			
Heavy Oil	**27,277**	**(13)%**	31,247
Light and Medium Oil	**25,089**	**(7)%**	27,121
NGLs (1)	**1,047**	**(13)%**	1,208
	53,413	**(10)%**	59,576
Total Crude Oil Production	**234,914**	**19%**	197,551

(1) NGLs include condensate volumes.

In the first quarter of 2017, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion and additional wells that were brought online. Production from Christina Lake increased due to incremental production volumes from the phase F expansion and reliable performance of our facilities. Ramp-up of phase G at Foster Creek and phase F at Christina Lake is progressing as planned and is expected to be completed in the second half of 2017.

Our Conventional crude oil production decreased from 2016 primarily due to expected natural declines.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended March 31, 2017	2016
Conventional	**348**	391
Oil Sands	**15**	17
	363	408

Our natural gas production decreased 11 percent compared with the first quarter of 2016 primarily due to expected natural declines.

Netbacks

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

	Crude Oil (1) ($/bbl)		**Natural Gas** ($/Mcf)	
	Three Months Ended March 31,			
	2017	2016	**2017**	2016
Sales Price	**41.41**	15.97	**2.99**	2.31
Royalties	**3.67**	0.92	**0.14**	0.09
Transportation and Blending	**5.14**	5.85	**0.12**	0.10
Operating Expenses	**10.27**	11.08	**1.34**	1.23
Production and Mineral Taxes	**0.22**	0.11	**0.02**	-
Netback Excluding Realized Risk Management	**22.11**	(1.99)	**1.37**	0.89
Realized Risk Management Gain (Loss)	**(4.53)**	8.16	**-**	-
Netback Including Realized Risk Management	**17.58**	6.17	**1.37**	0.89

(1) Includes NGLs.

Our average crude oil Netback for the first quarter of 2017, excluding realized risk management gains and losses, was substantially higher than the first quarter of 2016. Higher sales prices, consistent with the increase in benchmark prices, and a decrease in our per unit operating costs and transportation expenses, were partially offset by the rise in royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. The strengthening of the Canadian dollar compared with 2016 had a negative impact on our crude oil price of approximately $1.55 per barrel.

Our average natural gas Netback, excluding realized risk management gains and losses, increased primarily due to higher sales prices, consistent with the rise in the AECO benchmark price.

Refining

Crude oil runs and refined product output decreased compared with 2016 primarily due to planned turnarounds completed at both Refineries in the first quarter of 2017. Lower heavy crude oil volumes were processed due to the planned turnarounds and optimization of the total crude input slate.

	Three Months Ended March 31,		
	2017	**Percent Change**	2016
Crude Oil Runs (1) (Mbbls/d)	**406**	**(7)%**	435
Heavy Crude Oil (1)	**200**	**(17)%**	241
Refined Product (1) (Mbbls/d)	**433**	**(6)%**	460
Crude Utilization (1) (percent)	**88**	**(7)%**	95

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

In the first quarter of 2017, Refining and Marketing had an Operating Margin of $53 million compared with an Operating Margin loss of $23 million in 2016. The rise was primarily due to an increase in our gross margin, consistent with higher average market crack spreads. The increase in Operating Margin was partially offset by a realized risk management loss compared with a gain in 2016, a decline in crude utilization rates, a decrease in margins on the sale of secondary products, and higher operating costs.

Further information on the changes in our production volumes, items included in our Netbacks and refining results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the March 31, 2017 interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [(1)]

	Q1 2017	Q1 2016	**Percent Change**	Q4 2016
Crude Oil Prices (US$/bbl, unless otherwise indicated)				
Brent				
Average	**54.66**	35.08	**56%**	51.13
End of Period	**52.83**	39.60	**33%**	56.82
WTI				
Average	**51.91**	33.45	**55%**	49.29
End of Period	**50.60**	38.34	**32%**	53.72
Average Differential Brent-WTI	**2.75**	1.63	**69%**	1.84
WCS				
Average	**37.33**	19.21	**94%**	34.97
Average (C$/bbl)	**49.38**	26.39	**87%**	46.63
End of Period	**39.77**	26.75	**49%**	38.81
Average Differential WTI-WCS	**14.58**	14.24	**2%**	14.32
Condensate (C5 @ Edmonton)				
Average [(2)]	**52.26**	34.39	**52%**	48.33
Average Differential WTI-Condensate (Premium)/Discount	**(0.35)**	(0.94)	**(63)%**	0.96
Average Differential WCS-Condensate (Premium)/Discount	**(14.93)**	(15.18)	**(2)%**	(13.36)
Average Refined Product Prices (US$/bbl)				
Chicago Regular Unleaded Gasoline ("RUL")	**63.13**	42.00	**50%**	59.46
Chicago Ultra-low Sulphur Diesel ("ULSD")	**63.86**	44.55	**43%**	61.50
Refining Margin: Average 3-2-1 Crack Spread [(3)] (US$/bbl)				
Chicago	**11.54**	9.58	**20%**	10.96
Average Natural Gas Prices				
AECO (C$/Mcf)	**2.94**	2.11	**39%**	2.81
NYMEX (US$/Mcf)	**3.32**	2.09	**59%**	2.98
Basis Differential NYMEX-AECO (US$/Mcf)	**1.10**	0.56	**96%**	0.86
Foreign Exchange Rate (US$ per C$1)				
Average	**0.756**	0.728	**4%**	0.750

(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks table in the Operating Results section of this MD&A.
(2) The average Canadian dollar condensate benchmark price for the first quarter of 2017 was $69.13 per barrel (2016 – $47.24 per barrel).
(3) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

Crude Oil Benchmarks

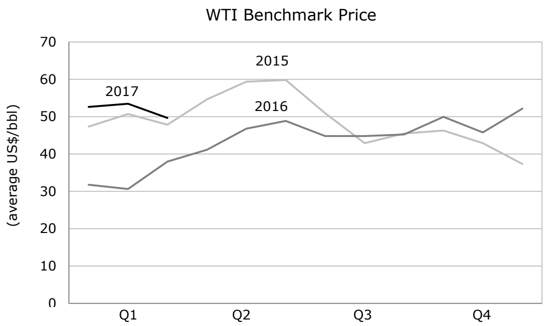
Average crude oil benchmark prices in the first quarter of 2017 increased significantly compared with 2016. Prices rose as the Organization of Petroleum Exporting Countries ("OPEC"), along with select non-OPEC countries, such as Russia, reached an agreement in the fourth quarter of 2016 to reduce production. In the first quarter of 2017, crude oil prices increased due to compliance with the plan to reduce production and expectations of future global crude oil inventory draws.

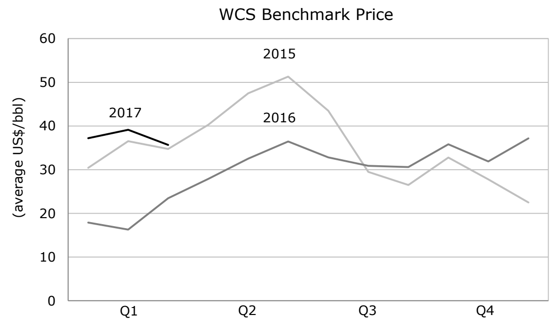
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI benchmark prices weakened relative to Brent due to growing U.S. crude oil supply resulting in a build of U.S. crude oil inventory.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential widened slightly from the first quarter of 2016 due to increasing heavy oil production in Alberta and limited pipeline capacity.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost attributed to transporting the condensate to Edmonton.

The average WTI-Condensate differential narrowed in the first quarter of 2017 compared with 2016. Condensate prices rose relative to WTI as higher seasonal demand for condensate blending was further supported by increased demand resulting from the ramp-up of oil sands production in Alberta.

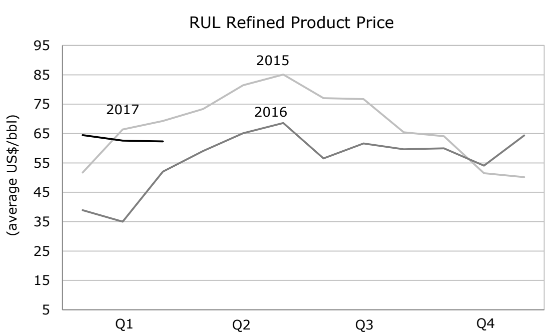


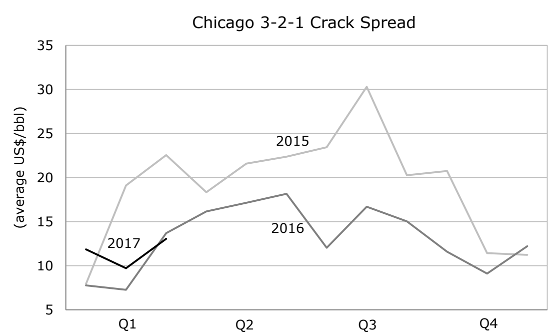


Refining Benchmarks

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 valued on a last in, first out accounting basis.

Average Chicago refined product prices increased in the first quarter of 2017 compared with 2016 primarily due to higher crude oil prices and stronger refined product demand. The increase in average Chicago 3-2-1 crack spreads in 2017 was due to increasing U.S. crude oil supply, resulting in a wider Brent-WTI differential, and strong refined product demand reducing refined product inventories. Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average natural gas prices increased in the first quarter of 2017, despite mild average temperatures over the quarter, due to declining supply and lower storage inventory levels relative to 2016.

Foreign Exchange Benchmark

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 strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In the first quarter of 2017, the Canadian dollar strengthened relative to the U.S. dollar due to higher crude oil benchmark prices, partially offset by U.S. interest rate increases. The strengthening of the Canadian dollar, compared with the first quarter of 2016, had a negative impact of approximately $145 million on our revenues.

As at March 31, 2017, the Canadian dollar was stronger relative to the U.S. dollar than as at December 31, 2016, which resulted in $56 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

Significant improvements in commodity prices in the first quarter of 2017 was the primary driver of our financial results. The following key performance measures are discussed in more detail within this MD&A.

	2017	2016				2015			
($ millions, except per share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	**3,865**	3,642	3,240	3,007	2,245	2,924	3,273	3,726	3,141
Operating Margin (1)	**450**	595	487	541	144	357	602	932	548
Cash From Operating Activities	**328**	164	310	205	182	322	542	335	275
Adjusted Funds Flow (2)	**323**	535	422	440	26	275	444	477	495
Operating Earnings (Loss) (2)	**(39)**	321	(236)	(39)	(423)	(438)	(28)	151	(88)
Per Share – Diluted ($)	**(0.05)**	0.39	(0.28)	(0.05)	(0.51)	(0.53)	(0.03)	0.18	(0.11)
Net Earnings (Loss)	**211**	91	(251)	(267)	(118)	(641)	1,801	126	(668)
Per Share – Basic and Diluted ($)	**0.25**	0.11	(0.30)	(0.32)	(0.14)	(0.77)	2.16	0.15	(0.86)
Capital Investment (3)	**313**	259	208	236	323	428	400	357	529
Dividends									
Cash Dividends	**41**	42	41	42	41	132	133	125	138
In Shares From Treasury	**-**	-	-	-	-	-	-	98	84
Per Share ($)	**0.05**	0.05	0.05	0.05	0.05	0.16	0.16	0.2662	0.2662

(1) *Additional subtotal found in Note 1 of the interim Consolidated Financial Statements and defined in this MD&A.*
(2) *Non-GAAP measure defined in this MD&A.*
(3) *Includes expenditures on PP&E, E&E assets, and Assets Held for Sale.*

Revenues

($ millions)	
Revenues for the Three Months Ended March 31, 2016	**2,245**
Increase (Decrease) due to:	
Oil Sands	**565**
Conventional	**70**
Refining and Marketing	**1,016**
Corporate and Eliminations	**(31)**
Revenues for the Three Months Ended March 31, 2017	**3,865**

Combined Oil Sands and Conventional revenues almost doubled in the first quarter of 2017 due to higher commodity prices and a rise in sales volumes, partially offset by higher royalties and the strengthening of the Canadian dollar relative to the U.S. dollar.

Revenues from our Refining and Marketing segment increased 64 percent from 2016. Refining revenues rose due to the increase in refined product pricing, consistent with higher Chicago RUL and Chicago ULSD benchmark prices. The rise was partially offset by decreased refined product output associated with the planned turnarounds at both Refineries in 2017 and the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group more than doubled from the first quarter of 2016, primarily due to higher sales prices and an increase in purchased crude oil and condensate sales volumes, partially offset by a decline in purchased natural gas sales volumes.

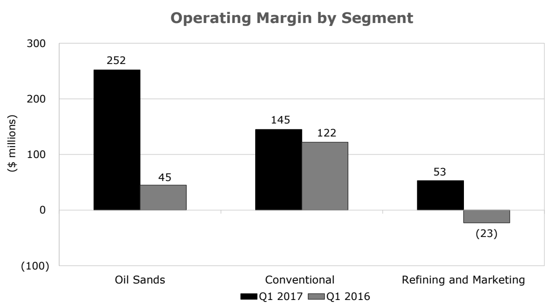
Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

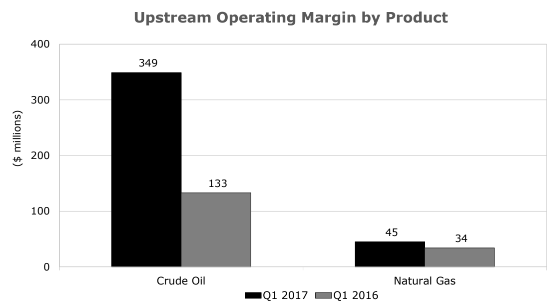
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Margin

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

	Three Months Ended March 31,	
($ millions)	**2017**	2016
Revenues	**3,963**	2,312
(Add) Deduct:		
Purchased Product	**2,330**	1,428
Transportation and Blending	**617**	451
Operating Expenses	**469**	452
Production and Mineral Taxes	**5**	2
Realized (Gain) Loss on Risk Management Activities	**92**	(165)
Operating Margin	**450**	144





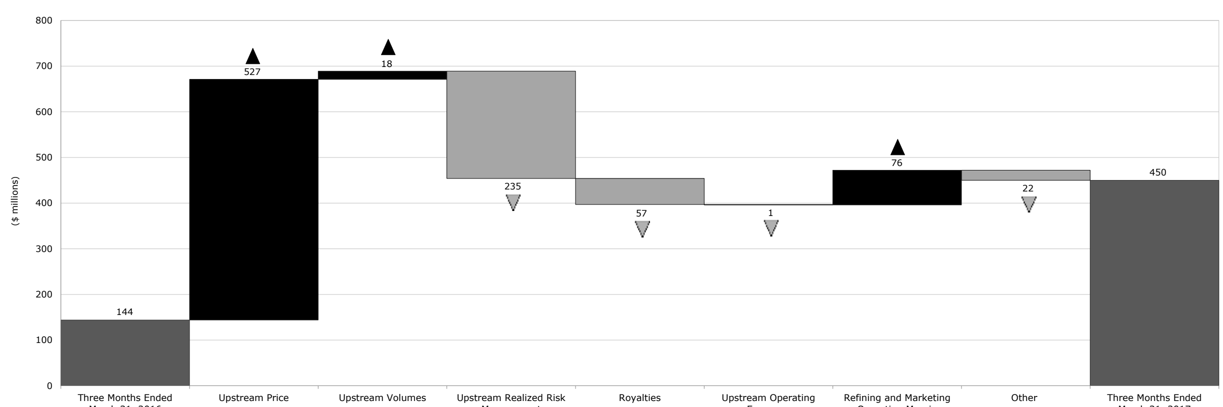
Operating Margin increased $306 million in the first quarter of 2017 primarily due to:

- Our average crude oil sales price almost tripling and our average natural gas sales price increasing 29 percent, consistent with higher associated benchmark prices;
- Higher Operating Margin from Refining and Marketing due to a rise in average market crack spreads, partially offset by a realized risk management loss compared with a gain in 2016, a decline in crude utilization rates, a decrease in margins on the sale of secondary products, and an increase in operating costs; and
- An 11 percent increase in our crude oil sales volumes.

These increases in Operating Margin were partially offset by:

- Realized risk management losses of $90 million, excluding Refining and Marketing, compared with gains of $145 million in the first quarter of 2016;
- A rise in transportation and blending expenses due to higher blending costs, related to an increase in condensate prices and condensate volumes required for blending our increased oil sands production; and
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate) and a rise in our crude oil sales price.

Operating Margin Variance



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

Cash From Operating Activities and Adjusted Funds Flow

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

($ millions)	Three Months Ended March 31, 2017	2016
Cash From Operating Activities	**328**	182
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(31)**	(29)
Net Change in Non-Cash Working Capital	**36**	185
Adjusted Funds Flow	**323**	26

In the first quarter of 2017, Cash From Operating Activities and Adjusted Funds Flow increased significantly primarily as a result of higher Operating Margin, as discussed above. The change in non-cash working capital for the three months ended March 31, 2017 was primarily due to a decline in accounts receivable, partially offset by a decrease in accounts payable. Accounts receivable declined as a result of lower crude oil sales volumes in March 2017 as compared to December 2016. Accounts payable declined primarily due to the repayment of a note payable to partner in the first quarter of 2017. In addition, upstream inventory increased primarily due to fulfilling our linefill requirements on the Athabasca Pipeline Twinning Project.

Operating Earnings (Loss)

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

($ millions)	Three Months Ended March 31, 2017	2016
Earnings (Loss), Before Income Tax	**260**	(335)
Add (Deduct):		
Unrealized Risk Management (Gain) Loss [(1)]	**(279)**	149
Non-operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**(56)**	(413)
(Gain) Loss on Divestiture of Assets	**1**	-
Operating Earnings (Loss), Before Income Tax	**(74)**	(599)
Income Tax Expense (Recovery)	**(35)**	(176)
Operating Earnings (Loss)	**(39)**	(423)

(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 Loss decreased compared with the first quarter of 2016 primarily due to an increase in Cash from Operating Activities and Adjusted Funds Flow, as discussed above, and a decline in depreciation, depletion and amortization ("DD&A") primarily related to an impairment loss of $170 million associated with our Northern Alberta CGU recorded in 2016. In 2017, exploration expense was $3 million (2016 – $1 million).

Net Earnings

($ millions)	
Net Earnings (Loss) for the Three Months Ended March 31, 2016	**(118)**
Increase (Decrease) due to:	
Operating Margin	**306**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**428**
Unrealized Foreign Exchange Gain (Loss)	**(337)**
Gain (Loss) on Divestiture of Assets	**(1)**
Expenses [(1)]	**22**
DD&A	**179**
Exploration Expense	**(2)**
Income Tax Recovery (Expense)	**(266)**
Net Earnings (Loss) for the Three Months Ended March 31, 2017	**211**

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

In the first quarter of 2017, Net Earnings increased primarily due to:

- Unrealized risk management gains of $279 million (2016 – unrealized losses of $149 million); and
- Lower Operating Losses, as discussed above.

The increase was partially offset by non-operating unrealized foreign exchange gains of $56 million as compared with gains of $413 million in 2016 and a deferred income tax expense of $71 million (2016 – recovery of $190 million).

Net Capital Investment

($ millions)	Three Months Ended March 31, 2017	2016
Oil Sands	**172**	227
Conventional	**88**	39
Refining and Marketing	**46**	52
Corporate and Eliminations	**7**	5
Capital Investment	**313**	323
Acquisitions and Divestitures	**-**	-
Net Capital Investment (1)	**313**	323

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

Capital investment in the first quarter of 2017 declined three percent compared with 2016. In the first quarter of 2016, work continued on the two expansion phases, Foster Creek phase G and Christina Lake phase F. In 2017, Oil Sands capital investment focused primarily on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells, near-term expansion phases, and progression of certain emerging assets; and module assembly for Christina Lake expansion phase G. Conventional capital investment focused on sustaining capital and the ramp-up of the tight oil drilling program in Southern Alberta. Capital investment in the Refining and Marketing segment focused on capital maintenance and reliability work.

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

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our uses of cash 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 flows. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	Three Months Ended March 31, 2017	2016
Adjusted Funds Flow	**323**	26
Capital Investment (Sustaining and Growth)	**313**	323
Free Funds Flow (1)	**10**	(297)
Cash Dividends	**41**	41
	(31)	(338)

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

On March 29, 2017, we entered into a purchase and sale agreement (the "Acquisition Agreement") with ConocoPhillips to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets. The Acquisition, which is subject to customary closing conditions and regulatory approvals, is expected to close in the second quarter of 2017. See the Transformational Acquisition section of this MD&A for more details. We intend to update our 2017 guidance estimates, including future capital investment, after the transaction closes. In the first quarter of 2016, capital investment in excess of Adjusted Funds Flow was funded through 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 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 reportable segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

Revenues by Reportable Segment

($ millions)	Three Months Ended March 31, 2017	2016
Oil Sands	**1,035**	470
Conventional	**324**	254
Refining and Marketing	**2,604**	1,588
Corporate and Eliminations	**(98)**	(67)
	3,865	2,245

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 project at Telephone Lake. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

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

- Increasing crude oil production by 32 percent due to incremental production volumes from ramp up of Foster Creek phase G and Christina Lake phase F, both of which started-up in the second half of 2016;
- Achieving crude oil Netbacks, excluding realized risk management activities, of $21.52 per barrel compared with a loss of $6.10 per barrel in 2016;
- Reducing our crude oil operating costs by $0.55 per barrel, a six percent decline; and
- Generating Operating Margin net of capital investment of $80 million, an increase of $262 million.

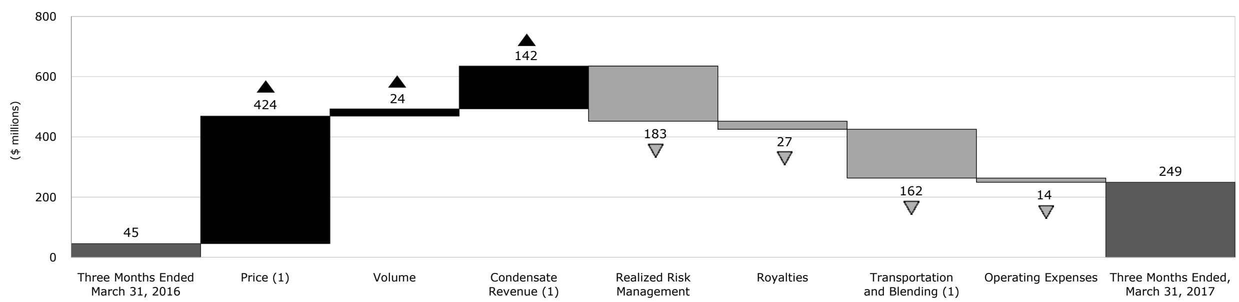
Oil Sands – Crude Oil

Financial Results

($ millions)	Three Months Ended March 31, 2017	2016
Gross Sales	**1,055**	465
Less: Royalties	**27**	-
Revenues	**1,028**	465
Expenses		
Transportation and Blending	**566**	404
Operating	**136**	122
(Gain) Loss on Risk Management	**77**	(106)
Operating Margin	**249**	45
Capital Investment	**169**	227
Operating Margin Net of Related Capital Investment	**80**	(182)

In 2016, capital investment in excess of Operating Margin from Oil Sands was funded through Operating Margin generated by our Conventional segment as well as our cash balance on hand.

Operating Margin Variance



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

Revenues

Price

In the first quarter of 2017, our average crude oil sales price increased substantially to $38.08 per barrel (2016 – $10.13 per barrel). The significant rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend ("CDB") benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. Our crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

The WCS-CDB differential narrowed by nine percent compared with the first quarter of 2016 to a discount of US$1.79 per barrel. In the first quarter of 2017, 85 percent of our Christina Lake production was sold as CDB (2016 – 90 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. Sales volumes at Christina Lake were significantly lower than production volumes during the three months ended March 31, 2017 primarily due to fulfilling our linefill requirements on the Athabasca Pipeline Twinning Project.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2017	Percent Change	2016
Foster Creek	**80,866**	**33%**	60,882
Christina Lake	**100,635**	**31%**	77,093
	181,501	**32%**	137,975

In the first quarter of 2017, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion and additional wells that were brought online. Production from Christina Lake increased compared with 2016 due to incremental production volumes from the phase F expansion and reliable performance of our facilities. Ramp-up of phase G at Foster Creek and phase F at Christina Lake is progressing well and is expected to be completed in the second half of 2017.

Condensate

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

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. In the first quarter of 2017, our royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2016.

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

Effective Royalty Rates

(percent)	Three Months Ended March 31, **2017**	2016
Foster Creek	**8.5**	(4.9)
Christina Lake	**2.7**	1.2

Royalties increased $27 million compared with the first quarter of 2016. At Foster Creek, higher royalties were due to a rise in crude oil sales prices and an increase in the WTI benchmark price (which determines the royalty rate). In the first quarter of 2016, the negative royalty rate was primarily due to low crude oil sales prices and a true-up of the 2015 royalty calculation. The Christina Lake royalty rate increased in 2017 as a result of the rise in the WTI benchmark price (which determines the royalty rate) and higher sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $162 million. Blending costs increased due to higher condensate prices and a rise in condensate volumes required for our increased production. Our condensate costs were higher than the average Edmonton benchmark price in the first quarter, primarily due to the transportation expense associated with moving the condensate to our oil sands projects, partially offset by the utilization of lower priced inventory.

Transportation costs increased slightly primarily due to higher sales volumes, partially offset by a decline in sales to the U.S. market resulting in lower costs associated with pipeline tariffs. To help ensure adequate capacity for our expected production growth, we have capacity commitments in excess of our current production. Production growth is expected to reduce our per-barrel transportation costs.

In addition, rail costs rose as higher volumes were moved by rail in the first quarter of 2017 as a result of increased pipeline congestion. We transported an average of 5,236 barrels per day of crude oil by rail (2016 – 2,314 barrels per day).

Operating

Primary drivers of our operating expenses for the first quarter were workforce, fuel, workovers, and chemical costs. Total operating expenses increased $14 million primarily as a result of higher natural gas prices that increased fuel costs, partially offset by a decline in repairs and maintenance activities.

Per-unit Operating Expenses

($/bbl)	2017	Percent Change	2016
	Three Months Ended March 31,		
Foster Creek			
Fuel	**2.93**	**18%**	2.48
Non-fuel	**7.06**	**(26)%**	9.57
Total	**9.99**	**(17)%**	12.05
Christina Lake			
Fuel	**2.57**	**31%**	1.96
Non-fuel	**5.51**	**(2)%**	5.65
Total	**8.08**	**6%**	7.61
Total	**8.97**	**(6)%**	9.52

In the first quarter of 2017, Foster Creek fuel costs rose compared with 2016 due to higher natural gas prices partially offset by a decline in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined on a per-barrel basis primarily due to higher production, in addition to:

- A true-up of the 2016 emissions charge under the Specified Gas Emitters Regulation ("SGER") program; and
- Lower repairs and maintenance costs from focusing on critical operational activities.

The decline was partially offset by an increase in workover activities related to more pump changes and higher well servicing costs.

At Christina Lake, fuel costs increased in 2017 due to higher natural gas prices partially offset by a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased on a per-barrel basis primarily due to higher production, in addition to:

- Lower well workover costs related to a decrease in well servicing fees;
- A decrease in electricity costs related to the electrical generation capacity added in the fourth quarter of 2016; and
- Lower repairs and maintenance costs from focusing on critical operational activities.

The decline was partially offset by a true-up of the 2016 emissions charged under the SGER program. Christina Lake's emissions are below the threshold set by the SGER program and generate performance credits which are applied to the charges incurred at Foster Creek.

Netbacks [(1)]

	Foster Creek		Christina Lake	
	Three Months Ended March 31,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**40.62**	11.82	**35.86**	8.85
Royalties	**2.83**	(0.16)	**0.86**	0.05
Transportation and Blending	**7.72**	8.70	**4.13**	5.28
Operating Expenses	**9.99**	12.05	**8.08**	7.61
Netback Excluding Realized Risk Management	**20.08**	(8.77)	**22.79**	(4.09)
Realized Risk Management Gain (Loss)	**(5.73)**	9.49	**(4.52)**	7.43
Netback Including Realized Risk Management	**14.35**	0.72	**18.27**	3.34

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

Risk Management

Risk management activities in the first quarter of 2017 resulted in realized losses of $77 million (2016 – realized gains of $106 million), consistent with average benchmark prices exceeding our contract prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the first quarter of 2017, net of internal usage, was 15 MMcf per day (2016 – 17 MMcf per day). Operating Margin was $1 million in 2017, consistent with the first quarter of 2016 as higher natural gas prices were offset by lower production.

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2017	2016
Foster Creek	**70**	89
Christina Lake	**63**	114
	133	203
Narrows Lake	**5**	4
Telephone Lake	**24**	7
Grand Rapids	**-**	5
Other (1)	**10**	8
Capital Investment (2)	**172**	227

(1) Includes new resource plays and Athabasca natural gas.
(2) Includes expenditures on PP&E, E&E assets, and assets held for sale.

Existing Projects

Capital investment at Foster Creek in the first quarter of 2017 focused on sustaining capital related to existing production and stratigraphic test wells. Capital investment declined in the current quarter compared with 2016. In the first quarter of 2016, capital spending was focused on the completion of expansion phase G and stratigraphic test wells.

In 2017, Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells, and module assembly related to the phase G expansion. Capital investment decreased in the first quarter of 2017 compared with 2016. In the first quarter of 2016, capital was focused on the completion of expansion phase F and stratigraphic test wells.

Capital investment at Narrows Lake in 2017 focused on drilling of stratigraphic test wells to further progress the project. Capital investment remained relatively consistent in the first quarter of 2017 compared with 2016.

Emerging Projects

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

Drilling Activity

	Gross Stratigraphic Test Wells		Gross Production Wells (1)	
Three Months Ended March 31,	**2017**	2016	**2017**	2016
Foster Creek	**92**	95	**-**	4
Christina Lake	**98**	97	**-**	18
	190	192	**-**	22
Narrows Lake	**2**	-	**-**	-
Telephone Lake	**13**	-	**-**	-
Other	**1**	5	**-**	-
	206	197	**-**	22

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

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

Future Capital Investment

On March 29, 2017, we entered into a purchase and sale agreement with ConocoPhillips to acquire ConocoPhillips' 50 percent interest in FCCL, which will increase our interest in FCCL to 100 percent. The Acquisition, which is subject to customary closing conditions and regulatory approvals, will have an effective date of January 1, 2017 and is expected to close in the second quarter of 2017. See the Transformational Acquisition section of this MD&A for more details. We intend to update our 2017 guidance estimates, including future capital investment, after the transaction closes. The following future capital investment information does not reflect closing of the Acquisition.

Our 2017 Oil Sands capital investment is forecast to be between $685 million and $815 million. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

Foster Creek is currently producing from phases A through G. Capital investment for 2017 is forecast to be between $325 million and $375 million. We plan to continue focusing on sustaining capital related to existing production and to progress engineering and design work on phase H. Spending related to construction work on phase H was deferred in 2015 in response to the low commodity price environment. At our Investor Day in June 2017, we plan to provide an update on our plans for Foster Creek phase H.

Christina Lake is producing from phases A through F. Capital investment for 2017 is forecast to be between $300 million and $350 million, focused on sustaining capital and resuming construction of the phase G expansion, which had previously been deferred. Field construction of phase G, which has an initial design capacity of 50,000 gross barrels per day, has commenced and will continue ramp up in the first half of 2017. 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 and our new resource plays in 2017 is forecast to be between $60 million and $90 million, focusing on a stratigraphic test well program at Telephone Lake and Narrows Lake, and engineering and equipment preservation related to the suspension of construction at Narrows Lake. At our Investor Day in June 2017, we plan to provide an update on our plans for Narrows Lake phase A.

DD&A and Exploration Expense

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

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

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

While this illustrates the calculation of the implied depletion rate, our depletion rates result in a total average rate ranging between $10.80 to $11.90 per BOE. Amounts related to assets under construction and assets held for sale, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the December 31, 2016 Consolidated Financial Statements.

In the first quarter of 2017, Oil Sands DD&A increased $22 million due to higher sales volumes, partially offset by lower DD&A rates. The average depletion rate was approximately $10.70 per barrel compared with $11.55 per barrel in the first quarter of 2016, declining primarily due to the impact of proved reserves additions and lower future development costs. Future development costs, which compose approximately 65 percent of the depletable base, declined due to cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs and increased well pair spacing. This decline was partially offset by an increase in costs related to the expansion of the development area and inclusion of phase G costs at Christina Lake.

There was no exploration expense recorded in the first quarter of 2017 (2016 – $1 million).

Assets and Liabilities Held for Sale

Concurrent with the announcement to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets, we commenced marketing for sale certain non-core properties. This includes our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican region, and our Suffield crude oil and natural gas assets. As a result, in the Oil Sands segment, our Grand Rapids project was reclassified as held for sale as at March 31, 2017. The assets were recorded at the lesser of their carrying amount and fair value less costs to sell. The estimated fair value exceeded our carrying value. See the Assets and Liabilities Held for Sale in the Conventional section of this MD&A for more details on the reclassification of our Pelican Lake and Suffield assets.

CONVENTIONAL

Our Conventional operations include reliable 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 and waterflood 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 flows generated in our Conventional segment helps to fund future growth opportunities while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

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

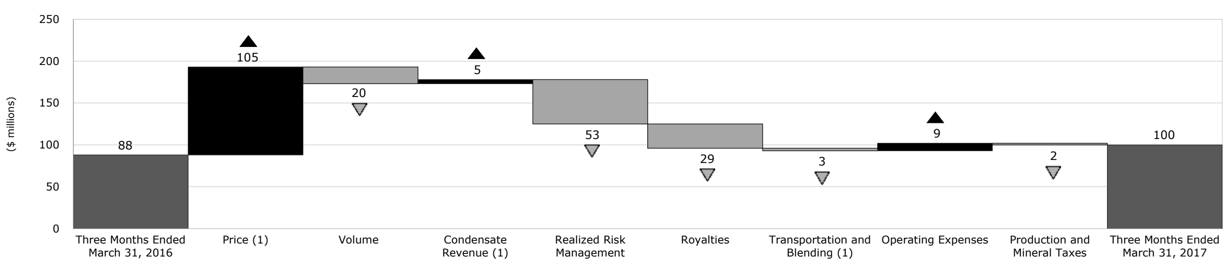
- Our average crude oil sales price increasing 75 percent to $52.13 per barrel;
- Crude oil and natural gas Netbacks, excluding realized risk management activities, of $23.96 per barrel (2016 – $7.73 per barrel) and $1.40 per Mcf (2016 – $0.92 per Mcf), respectively;
- Crude oil production averaging 53,413 barrels per day, decreasing 10 percent primarily due to expected natural declines; and
- Generating Operating Margin net of capital investment of $57 million, a decrease of 31 percent due to the more than doubling of capital investment primarily related to the ramp-up of the tight oil drilling program in Southern Alberta. In 2016, crude oil capital investment activities were limited in response to the low commodity price environment.

Conventional – Crude Oil

Financial Results

	Three Months Ended March 31,	
($ millions)	**2017**	2016
Gross Sales	**279**	189
Less: Royalties	**46**	17
Revenues	**233**	172
Expenses		
Transportation and Blending	**47**	44
Operating	**69**	78
Production and Mineral Taxes	**4**	2
(Gain) Loss on Risk Management	**13**	(40)
Operating Margin	**100**	88
Capital Investment	**85**	37
Operating Margin Net of Related Capital Investment	**15**	51

Operating Margin Variance



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

Revenues

Price

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

Our crude oil sales price averaged $52.13 per barrel in the first quarter of 2017, a 75 percent increase from 2016, due to higher crude oil benchmark prices, adjusted for applicable differentials, and the narrowing of the WCS-Condensate differential. This increase was partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. As the cost of condensate decreases relative to the price of blended crude oil, our heavy oil sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our heavy oil sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

	Three Months Ended March 31,		
(barrels per day)	**2017**	**Percent Change**	2016
Heavy Oil	**27,277**	**(13)%**	31,247
Light and Medium Oil	**25,089**	**(7)%**	27,121
NGLs	**1,047**	**(13)%**	1,208
	53,413	**(10)%**	59,576

Production decreased primarily as a result of expected natural declines.

Condensate

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

Royalties

Conventional crude oil royalties increased due to higher sales prices, and lower costs at our Weyburn property, partially offset by a reduction in sales volumes. In the first quarter of 2017, the effective crude oil royalty rate for our Conventional properties was 20.2 percent (2016 – 12.6 percent).

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

In the first quarter of 2017, production and mineral taxes increased slightly related to the rise in crude oil prices.

Expenses

Transportation and Blending

Transportation and blending costs increased slightly in the first quarter of 2017. Blending costs rose due to higher condensate prices, partially offset by a decrease in condensate volumes, consistent with lower production. In the first quarter of 2016, as a result of declining crude oil prices, we recorded a $3 million write-down of our blended crude oil inventory to net realizable value. There was no inventory write-down in 2017. Transportation charges declined primarily due to lower sales volumes.

Operating

Primary drivers of our operating expenses in the first quarter of 2017 were workforce, workovers, electricity, and property taxes and lease costs.

Operating expenses declined $0.31 per barrel primarily due to:

- Lower chemical costs associated with chemical optimization;
- A decrease in repairs and maintenance and workover costs due to a focus on critical activities;
- A decline in electricity costs as a result of a decrease in consumption, slightly offset by a rise in electricity prices;
- Lower waste fluid handling and trucking costs associated with pipeline usage optimization; and
- A decline in workforce costs.

These declines were partially offset by lower production volumes.

Netbacks [(1)]

($/bbl)	Heavy Oil 2017	Heavy Oil 2016	Light and Medium 2017	Light and Medium 2016
	Three Months Ended March 31,			
Sales Price	**47.77**	25.99	**56.84**	34.36
Royalties	**7.03**	1.40	**12.75**	5.18
Transportation and Blending	**3.40**	4.77	**2.70**	2.73
Operating Expenses	**12.86**	13.98	**16.77**	16.34
Production and Mineral Taxes	**0.02**	-	**1.95**	0.82
Netback Excluding Realized Risk Management	**24.46**	5.84	**22.67**	9.29
Realized Risk Management Gain (Loss)	**(3.09)**	7.98	**(2.51)**	7.90
Netback Including Realized Risk Management	**21.37**	13.82	**20.16**	17.19

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

Risk Management

Risk management activities for the first quarter resulted in realized losses of $13 million (2016 – realized gains of $40 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended March 31, 2017	2016
Gross Sales	**94**	82
Less: Royalties	**4**	3
Revenues	**90**	79
Expenses		
Transportation and Blending	**4**	3
Operating	**41**	42
Production and Mineral Taxes	**1**	-
(Gain) Loss on Risk Management	**-**	1
Operating Margin	**44**	33
Capital Investment	**3**	2
Operating Margin Net of Related Capital Investment	**41**	31

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

Revenues

Price

In the first quarter of 2017, our average natural gas sales price increased 30 percent to $3.00 per Mcf, consistent with the rise in the AECO benchmark price.

Production

Production decreased 11 percent to 348 MMcf per day due to expected natural declines.

Royalties

Royalties increased as a result of higher prices, partially offset by production declines. The average royalty rate in the first quarter was 4.9 percent (2016 – 4.5 percent).

Expenses

Operating

Primary drivers of our operating expenses were property taxes and lease costs, workforce, and repairs and maintenance. In the first quarter, operating expenses decreased slightly primarily due to a decline in electricity costs.

Risk Management

Risk management activities had no impact in the first quarter of 2017 (2016 – realized losses of $1 million).

Conventional – Capital Investment

($ millions)	Three Months Ended March 31, 2017	2016
Heavy Oil	**8**	10
Light and Medium Oil	**77**	27
Natural Gas	**3**	2
Capital Investment [(1)]	**88**	39

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

Capital investment in the first quarter of 2017 was primarily related to sustaining capital and tight oil development opportunities in southern Alberta. Capital investment increased compared with 2016 as a result of limited crude oil capital investment activities in 2016 in response to the low commodity price environment.

Drilling Activity

(net wells, unless otherwise stated)	Three Months Ended March 31, 2017	2016
Crude Oil	**20**	1
Recompletions	**-**	65
Gross Stratigraphic Test Wells	**26**	4

Drilling activity in the first quarter of 2017 focused on drilling stratigraphic test wells and horizontal production wells for tight oil in Southern Alberta.

Future Capital Investment

With the expectation of continued crude oil price volatility in 2017, we are taking a 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 2017 crude oil capital investment forecast is between $275 million and $325 million with spending plans mainly focused on sustaining capital and tight oil drilling opportunities in southern Alberta. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over 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 declined $201 million in the first quarter of 2017 primarily related to impairment charges of $170 million recorded in the first quarter of 2016 associated with our Northern Alberta CGU. No impairment charges or reversals were recorded in 2017. In addition, DD&A declined due to lower sales volumes and lower DD&A rates. The average depletion rate decreased by approximately seven percent in 2017 compared with the first quarter of 2016 primarily due to lower future development costs and a decline in PP&E as a result of the slowdown in our development plans, partially offset by a decline in proved reserves. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2016 due to minimal capital investment planned at Pelican Lake in the near term.

In 2017, exploration expense was $3 million. There was no exploration expense in 2016.

Assets and Liabilities Held for Sale

Concurrent with the announcement to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets, we commenced marketing for sale certain non-core properties. This includes our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican region, and our Suffield crude oil and natural gas assets. As a result, in the Conventional segment, our Pelican Lake and Suffield assets were reclassified as held for sale as at March 31, 2017. The assets were recorded at the lesser of their carrying amount and fair value less costs to sell. The estimated fair value exceeded our carrying value.

REFINING AND MARKETING

Cenovus is 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 the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In the first quarter of 2017, we loaded an average of 11,890 gross barrels per day (2016 – 6,713 gross barrels per day).

Refinery Operations [(1)]

	Three Months Ended March 31, 2017	2016
Crude Oil Capacity (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**406**	435
Heavy Crude Oil	**200**	241
Light/Medium	**206**	194
Refined Products (Mbbls/d)	**433**	460
Gasoline	**227**	229
Distillate	**131**	142
Other	**75**	89
Crude Utilization (percent)	**88**	95

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

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

In the first quarter of 2017, lower crude oil runs and refined product output reflect the increased scope of planned maintenance and planned turnarounds at both Refineries. In the first quarter of 2016, planned and unplanned maintenance at the Refineries was completed. In 2017, lower heavy crude oil volumes were processed primarily due to planned turnarounds and optimization of the total crude input slate.

Refining and Marketing Financial Results

($ millions)	Three Months Ended March 31, 2017	2016
Revenues	**2,604**	1,588
Purchased Product	**2,330**	1,428
Gross Margin	**274**	160
Expenses		
Operating	**219**	203
(Gain) Loss on Risk Management	**2**	(20)
Operating Margin	**53**	(23)
Capital Investment	**46**	52
Operating Margin Net of Related Capital Investment	**7**	(75)

Gross Margin

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

In the first quarter of 2017, the Refining and Marketing gross margin increased primarily due to higher average market crack spreads, associated with lower global refined product inventory and widening of the Brent-WTI differential. The increase in gross margin was partially offset by lower crude utilization rates, a decline in margins on the sale of secondary products, such as coke, asphalt and sulphur due to higher overall feedstock costs, and a stronger Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately $10 million on the gross margin. In addition, we recorded an inventory write-down of $10 million related to our refined product inventory (2016 – $3 million).

In the first quarter of 2017, the costs associated with Renewable Identification Numbers ("RINs") was $61 million (2016 – $62 million). The costs of RINs remained relatively consistent as the decrease in RINs benchmark prices were offset by an increase in the required RINs volume obligation.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2017 were maintenance, labour, utilities and supplies. Reported operating expenses increased compared with 2016 primarily due to increased maintenance activities associated with planned maintenance and turnarounds, and an increase in utility costs resulting from higher natural gas prices, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended March 31, 2017	2016
Wood River Refinery	**34**	36
Borger Refinery	**12**	14
Marketing	**-**	2
	46	52

Capital expenditures in the first quarter of 2017 focused on capital maintenance and reliability work. Capital investment declined $6 million in 2017. In the first quarter of 2016, work continued on the debottlenecking project at the Wood River refinery that was successfully completed in the third quarter of 2016.

In 2017, we expect to invest between $210 million and $240 million mainly related to capital maintenance and reliability work. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A decreased slightly in 2017, primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains on interest rate swaps and foreign exchange contracts. In the first quarter of 2017, our risk management activities resulted in $279 million of unrealized gains (2016 – unrealized losses of $149 million), including $24 million of unrealized gains related to our foreign exchange contracts entered into in anticipation of the Acquisition. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

($ millions)	Three Months Ended March 31, 2017	2016
General and Administrative	**43**	60
Finance Costs	**120**	124
Interest Income	**(17)**	(11)
Foreign Exchange (Gain) Loss, Net	**(76)**	(403)
Transaction Costs	**29**	-
Research Costs	**4**	18
(Gain) Loss on Divestiture of Assets	**1**	-
	104	(212)

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2017 were workforce and office rent. General and administrative expenses decreased by $17 million primarily due to a decline in long-term employee incentive costs related to a drop in our share price. In addition, we recorded a non-cash expense of $8 million in the first quarter of 2017 (2016 – $14 million) in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs declined $4 million in 2017 compared with the same period in 2016 as strengthening of the Canadian dollar relative to the U.S. dollar decreased interest incurred on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the first quarter was 5.3 percent (2016 – 5.3 percent).

Foreign Exchange

($ millions)	Three Months Ended March 31, 2017	2016
Unrealized Foreign Exchange (Gain) Loss	**(72)**	(409)
Realized Foreign Exchange (Gain) Loss	**(4)**	6
	(76)	(403)

The majority of unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was one percent stronger at March 31, 2017 compared with December 31, 2016, resulting in unrealized gains.

Transaction Costs

In the first quarter of 2017, we recorded $29 million of transaction costs related to the Acquisition. See the Transformational Acquisition section of this MD&A for more details on the Acquisition.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in the first quarter of 2017 was $18 million (2016 – $17 million).

Income Tax

($ millions)	Three Months Ended March 31, 2017	2016
Current Tax		
Canada	**(21)**	(27)
United States	**(1)**	-
Total Current Tax Expense (Recovery)	**(22)**	(27)
Deferred Tax Expense (Recovery)	**71**	(190)
	49	(217)

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

($ millions)	Three Months Ended March 31, 2017	2016
Earnings Before Income Tax	**260**	(335)
Canadian Statutory Rate	**27.0%**	27.0%
Expected Income Tax (Recovery)	**70**	(90)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(15)**	(27)
Non-Deductible Stock-Based Compensation	**2**	2
Non-Taxable Capital (Gains) Losses	**(7)**	(56)
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(7)**	(56)
Other	**6**	10
Total Tax (Recovery)	**49**	(217)
Effective Tax Rate	**18.8%**	64.8%

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

In the first quarter of 2017, a current tax recovery was recorded due to the recognition of prior period losses. A deferred tax expense was recorded for the quarter compared with a recovery in 2016 due to lower operating losses and unrealized risk management gains compared with losses in the prior year.

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended March 31, **2017**	2016
Cash From (Used In)		
Operating Activities	**328**	182
Investing Activities	**(459)**	(369)
Net Cash Provided (Used) Before Financing Activities	**(131)**	(187)
Financing Activities	**(52)**	(41)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**11**	6
Increase (Decrease) in Cash and Cash Equivalents	**(172)**	(222)

	March 31, 2017	December 31, 2016
Cash and Cash Equivalents	**3,548**	3,720
Committed and Undrawn Credit Facilities	**4,000**	4,000

Cash From (Used In) Operating Activities

Cash From Operating Activities increased in the first quarter of 2017 mainly due to higher Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $4,352 million at March 31, 2017 compared with $4,423 million at December 31, 2016.

The change in non-cash working capital from operating activities for the three months ended March 31, 2017 was primarily due to a decline in accounts receivable, partially offset by a decrease in accounts payable. Accounts receivable declined as a result of lower crude oil sales volumes in March 2017 as compared to December 2016. Accounts payable declined primarily due to the repayment of a note payable to partner in the first quarter of 2017. In addition, upstream inventory increased primarily due to fulfilling our linefill requirements on the Athabasca Pipeline Twinning Project.

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

Cash From (Used In) Investing Activities

In the first quarter of 2017, the change in cash used in investing activities was primarily due to a deposit of $173 million (US$129.5 million) relating to the Acquisition. The deposit will be applied against the purchase price at the date of closing. See the Transformational Acquisition section of this MD&A for more details.

Cash From (Used In) Financing Activities

In the first quarter of 2017, we paid dividends of $0.05 per share or $41 million (2016 – $0.05 per share or $41 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. Cash used in financing activities also included $10 million of transaction costs related to the Acquisition. See the Transformational Acquisition section of this MD&A for more details.

Our long-term debt at March 31, 2017 was $6,277 million (December 31, 2016 – $6,332 million) with no principal payments due until October 2019 (US$1.3 billion). At March 31, 2017, the principal amount of long-term debt outstanding in U.S. dollars remained unchanged since August 2012. The $55 million decrease in long-term debt is primarily due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at March 31, 2017, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flows from our crude oil, natural gas and refining operations to fund a portion of our cash requirements. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at March 31, 2017:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,548**	**N/A**
Committed Credit Facility – Tranche B	**1,000**	**April 2019**
Committed Credit Facility – Tranche A	**3,000**	**November 2019**
Base Shelf Prospectus (1)	**US$5,000**	**March 2018**

(1) Availability is subject to market conditions. See below and the Transformational Acquisition section of this MD&A for details related to the Acquisition.

Committed Credit Facility

As at March 31, 2017, no amounts had been drawn on our existing committed credit facility. See the Transformational Acquisition section of this MD&A for information regarding an expected draw at close of the Acquisition.

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

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

Base Shelf Prospectus

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

As at March 31, 2017, no issuances had been made under the base shelf prospectus. In connection with the Acquisition, on April 6, 2017, Cenovus closed a Bought-Deal Common Share Offering for 187.5 million common shares under the base shelf prospectus for gross proceeds of $3.0 billion. As at April 6, 2017, US$2.8 billion remains available under the base shelf prospectus. See the Transformational Acquisition section of this MD&A for more details.

Future Sources of Liquidity

On March 29, 2017, Cenovus entered into a purchase and sale agreement with ConocoPhillips. To finance a portion of the cash purchase price, Cenovus closed a Bought-Deal Common Share Offering and a Note Offering in the U.S. in early April 2017. The funds related to Note Offering were placed into escrow subject to closing of the Acquisition. In addition, at close of the Acquisition we expect to draw under our existing committed credit facility, borrow under a committed Bridge Facility, and use cash on hand to fund the remainder of the purchase price. See the Transformational Acquisition section of the MD&A for more details.

We remain committed to maintaining our investment grade credit ratings from S&P Global Ratings and DBRS Limited as well as the investment grade credit rating we recently received from Fitch Ratings.

Financial Measures

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

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

As at	**March 31, 2017**	December 31, 2016
Net Debt to Capitalization (1) (2)	**19%**	18%
Debt to Capitalization	**35%**	35%
Net Debt to Adjusted EBITDA (1)	**1.6x**	1.9x
Debt to Adjusted EBITDA	**3.7x**	4.5x

(1) Net Debt is defined as Debt net of Cash and Cash Equivalents.
(2) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

Debt to Capitalization remained consistent as lower debt balances from the strengthening of the Canadian dollar relative to the U.S. dollar were offset by higher net earnings primarily related to the increase in commodity prices. Debt to Adjusted EBITDA declined as a result of higher Adjusted EBITDA, primarily due to an increase in commodity prices, partially offset by the lower long-term debt balance.

Additional information regarding our financial measures and capital structure can be found in the notes to the December 31, 2016 Consolidated Financial Statements and the March 31, 2017 interim Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

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

Refer to Note 18 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at March 31, 2017	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**42,569**	**37,176**
Other Stock-Based Compensation Plans (1)	**10,280**	**1,707**

(1) Includes PSUs, RSUs, and DSUs.

Contractual Obligations and Commitments

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

In the first quarter of 2017, total commitments were $26.7 billion, of which $23.2 billion were for various transportation commitments. In 2017, transportation commitments decreased by $3.1 billion from December 31, 2016 primarily due to our withdrawal from certain transportation initiatives. Transportation commitments include $16 billion that are subject to regulatory approval or have been approved but are not yet in service (2016 – $19 billion). Terms are up to 20 years subsequent to the date of commencement and should help align our future transportation requirements with our anticipated production growth.

As at March 31, 2017, there were outstanding letters of credit aggregating $254 million issued as security for performance under certain contracts (December 31, 2016 – $258 million).

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. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our interim Consolidated Financial Statements.

RISK MANAGEMENT

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

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We continue to be exposed to the risks identified in our 2016 annual MD&A.

The following provides an update on our risks related to commodity prices, foreign exchange rates, as well as risks related to the Acquisition.

Commodity Price Risk

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 20 and 21 to the interim Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

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

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

Impact of Financial Risk Management Activities

	Three Months Ended March 31,					
	2017			2016		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**90**	**(251)**	**(161)**	(164)	118	(46)
Refining	**2**	**-**	**2**	(4)	3	(1)
Power	**-**	**-**	**-**	3	(14)	(11)
Interest Rate	**-**	**(4)**	**(4)**	-	42	42
Foreign Exchange	**-**	**(24)**	**(24)**	-	-	-
(Gain) Loss on Risk Management	**92**	**(279)**	**(187)**	(165)	149	(16)
Income Tax Expense (Recovery)	**(24)**	**75**	**51**	43	(41)	2
(Gain) Loss on Risk Management, After Tax	**68**	**(204)**	**(136)**	(122)	108	(14)

In the first quarter of 2017, we recorded realized losses on crude oil risk management activities, consistent with the average benchmark price exceeding our contract prices. We recorded unrealized gains on our crude oil financial instruments primarily due to the realization of settled positions and changes in market prices.

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. To manage exposure to exchange rate fluctuations, Cenovus periodically enters into foreign exchange contracts. As at March 31, 2017, we had a notional amount of US$4.8 billion in foreign exchange forwards and options entered into in anticipation of the Acquisition. See the Transformational Acquisition section of this MD&A for more details. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Risks Related to the Acquisition

Possible Failure to Complete or Delay in Completion of the Acquisition

The closing of the Acquisition is subject to the required regulatory approvals and the satisfaction of certain closing conditions. The closing of the Acquisition will also require us to draw on our existing committed credit facility and a committed Bridge Facility, which have certain conditions. There is no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. If they are not satisfied or waived, the Acquisition will not be completed. In addition, a substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms or conditions in the approvals could have a material adverse effect on our ability to complete the Acquisition and on our business, financial condition or results of operations following the Acquisition. If the Acquisition is not completed as contemplated, we could suffer adverse consequences, including the loss of investor confidence. In addition, if the Acquisition is not completed we would have discretion as to the use of the net proceeds of the Bought-Deal Common Share Offering, as described below.

Discretion as to the Use of Proceeds From the Bought-Deal Common Share Offering if the Acquisition is not Completed

We intend to use the net proceeds of the Bought-Deal Common Share Offering, together with the Note Offering, borrowings under our existing committed credit facility, a committed Bridge Facility, and a portion of our cash on hand to pay the cash purchase price and pay certain fees and expenses related to the Acquisition. However, the Acquisition is subject to the satisfaction or waiver of certain conditions, some of which are beyond our control, and the Bought-Deal Common Share Offering was not conditional upon the consummation of the Acquisition. There can be no assurances that the Acquisition will occur on the terms set forth in the Acquisition Agreement or at all. In the event that the Acquisition is not completed, we may use the net proceeds of the Bought-Deal Common Share Offering to, among other things, reduce our indebtedness, finance future growth opportunities including acquisitions and investments, finance our capital expenditures, repurchase outstanding Common Shares or for general corporate purposes. Accordingly, our management and Board of Directors would have discretion as to the use of the net proceeds of the Bought-Deal Common Share Offering, and there can be no assurance as to how the net proceeds would be reallocated.

Unexpected Costs or Liabilities Related to the Acquisition

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

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

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

Realization of Acquisition Benefits

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

Amount of Contingent Payments

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

Significant Transaction and Related Costs

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

Operational and Reserves and Resources Risks Relating to the Acquired Assets

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

Risk of Default in the Repayment of Borrowings under the Acquisition Credit Facilities

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

Increased Indebtedness

If the Acquisition is consummated on the terms contemplated in the Acquisition Agreement, we anticipate that we will borrow up to $4.6 billion, through drawdowns on our existing committed credit facility and committed Bridge Facility, and by the issuance of US$2.9 billion in senior unsecured notes. Such borrowings will represent a significant increase in Cenovus's consolidated indebtedness. Such additional indebtedness will increase Cenovus's interest expense and debt service obligations and may have a negative effect on Cenovus's results of operations.

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

Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. The increased indebtedness of Cenovus arising from the Acquisition could be a factor considered by the ratings agencies in downgrading Cenovus's credit rating. If a rating agency were to downgrade Cenovus's credit rating, Cenovus's borrowing costs could increase and its funding sources could decrease. In addition, a failure by Cenovus to maintain its current credit ratings could affect its business relationships with suppliers and operating partners. A credit downgrade could also adversely affect the availability and cost of capital needed to fund the growth investments that are a central element to Cenovus's long-term business strategy.

Exchange Rate Risk

In addition to the net proceeds of the Bought-Deal Common Share Offering and the Note Offering, advances under our existing committed credit facility and committed Bridge Facility will be used to finance a portion of the cash purchase price. As we will fund a portion of the cash purchase price from a combination of Canadian and U.S. dollar denominated sources, and the cash purchase price of the Acquisition is denominated in U.S. dollars, a significant decline in the value of the Canadian dollar relative to the U.S. dollar at the time of closing of the Acquisition could increase the cost to Cenovus of financing the cash purchase price in Canadian dollar terms. Future events that may significantly increase or decrease the risk of future movement in the exchange rates cannot be predicted.

British Columbia Exposure

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

Aboriginal Claims

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

Climate Change Regulation

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

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

Environmental Regulation

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

Royalty Regime

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

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

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

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

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

Other Risks

U.S. Administration

Recent changes to the federal administration in the U.S. may result in legislative and regulatory changes that could have an adverse effect on Cenovus. In particular, the 2016 U.S. presidential election and the related changes in political agenda, coupled with the transition of administration, has created uncertainty as to the position the U.S. federal government will take with respect to world affairs and events. This uncertainty may include issues such as U.S. support for existing treaty and trade relationships with other countries, including Canada. In particular, proposals to implement a border adjustment tax may, if implemented, lead to unfavourable tax treatment on goods imported to the U.S. from Canada, and have a significant impact on Canadian companies that do business in the U.S. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on Cenovus, decrease U.S. demand for Cenovus's products, or otherwise negatively impact Cenovus, which may have a material adverse effect on our business, financial condition and operations. In addition, this uncertainty may adversely impact (a) the ability or willingness of Canadian companies to transact business with companies such as Cenovus whose products are being exported to the U.S.; (b) our profitability, particularly if the U.S. imposes any border adjustment taxes and/or the Government of Canada imposes new restrictions on imports from the U.S.; (c) regulation and trade agreements affecting the U.S. and Canada; (d) global stock markets (including the TSX); and (e) general global economic conditions. All of these factors are outside of our control, but may nonetheless lead us to adjust our strategy in order to compete effectively in global markets.

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 and annual MD&A for the year ended December 31, 2016.

Critical Judgments in Applying Accounting Policies

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

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty during the three months ended March 31, 2017. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2016.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the three months ended March 31, 2017.

New Accounting Standards and Interpretations not yet Adopted

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

Revenue Recognition

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

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

Leases

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

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

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

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

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2017 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

OUTLOOK

We expect 2017 will be a transformational year for Cenovus. The Acquisition will increase our interest in FCCL to 100 percent and the Deep Basin Assets will give us an additional growth platform in Alberta and British Columbia. The Acquisition, which is subject to customary closing conditions and regulatory requirements, will have an effective date of January 1, 2017 and is expected to close in the second quarter of 2017.

Additional information on our spending plans, and the potential impact of the Acquisition, is available in our material change report dated April 5, 2017 available on SEDAR and EDGAR. We also intend to provide updated guidance after closing of the Acquisition and at our Investor Day in June 2017.

We are well-positioned for what is anticipated to be another year of market and commodity price volatility. We will continue to look for ways to increase our margins through strong operating performance and cost leadership, while delivering safe and reliable operations. Proactively managing our market access commitments and opportunities will assist with our goal of reaching a broader customer base to secure a higher sales price for our crude oil.

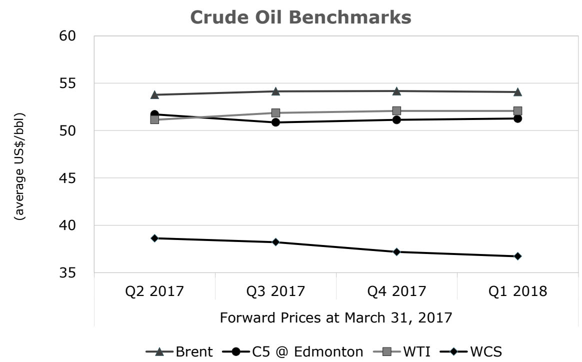
We have reduced the amount of capital needed to sustain our base business and expand our projects, which will allow us to reactivate growth in a disciplined manner. Together, these efforts will help to ensure our financial resilience.

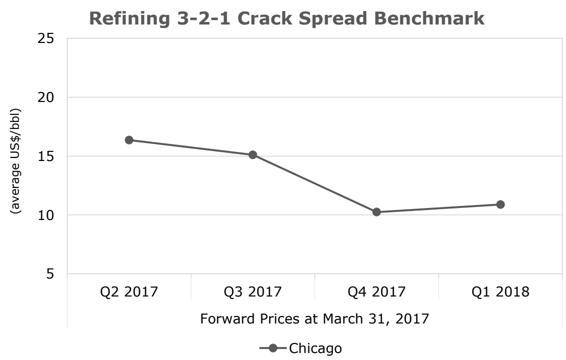
The following outlook commentary is focused on the next twelve months.

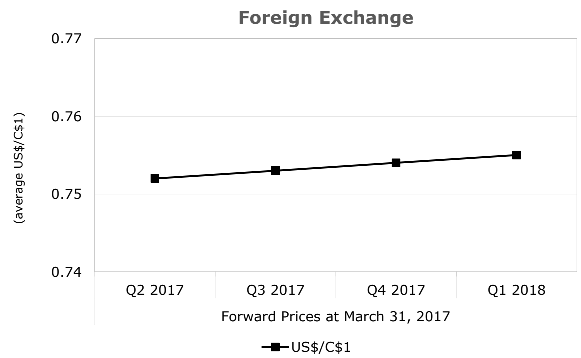
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, compliance of OPEC and select non-OPEC countries with the plan to reduce production, the impact of geopolitical supply disruptions, and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect a modest crude oil price improvement in the next twelve months.
- We anticipate that the WTI-WCS differential will widen due to increasing heavy oil production in Alberta and limited pipeline capacity.







U.S. refining crack spreads are expected to follow historical seasonal patterns over the next twelve months as we expect that they will be impacted by the pace of rebalancing excess crude oil and refined product inventories.

The Canadian dollar will likely continue to be tied to crude oil prices, tempered by expectations of rising interest rates in the U.S. Overall, excluding the change in crude oil prices, a stronger Canadian dollar is expected to have a negative impact on our revenues and Operating Margin.

Natural gas prices are anticipated to improve in the next twelve months due to limited supply growth, strengthening U.S. industrial demand, and an increase in U.S. natural gas export capacity. We expect that supply growth will be impacted by a relatively low U.S. natural gas rig count and pipeline congestion in the U.S. Northeast. However, significantly higher prices will likely be limited by the ability of the power sector to use coal as a substitute for natural gas.

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

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

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

Key Priorities for 2017

Maintain Financial Resilience and Transaction Execution

Maintaining our financial resilience, while maintaining safe operations, continues to be a top priority. We anticipate closing the Acquisition in the second quarter of 2017. The safe and efficient integration of the Deep Basin assets will be a priority. We are committed to maintaining our financial resilience following the close of the Acquisition. Our first priority following completion of the Acquisition will be to optimize our asset portfolio and capital structure, including a plan to repay the committed Bridge Facility.

Disciplined and Value-added Growth

We intend to update our 2017 capital investment guidance after the close of the Acquisition. Based on our December 8, 2016 guidance, which does not reflect the Acquisition, we anticipated capital investment in 2017 to be between $1.2 billion and $1.4 billion. We planned to direct the majority of our 2017 capital budget towards sustaining oil sands production and base production at our other operations. A portion of our capital budget is planned for growth at our existing oil sands assets as well as at our tight oil assets in southern Alberta. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

Sustainable Cost Improvements

In the past two years, we have achieved substantial improvements in our operating and sustaining capital costs through identifying efficiencies, maximizing the strengths of our functional business model, and disciplined manufacturing. In 2017, we plan to continue to focus on making sustainable cost improvements across the organization. We anticipate maintaining lower costs while increasing production and capital investment.

Market Access

Market access constraints for Canadian crude oil continue to be a challenge. In 2017, we plan to continue assessing a variety of options available to market our growing oil sands production, including tidewater access.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2016 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2017 price forecast. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2016 and our Statement of Contingent and Prospective Resources.

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

Forward-looking Information

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

Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast", "future", "target", "position", "project", "committed", "can be", "pursue", "capacity", "could", "should", "will", "focus", "outlook", "potential", "priority", "may", "strategy", "forward", or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules, including expected timing for oil sands expansion phases and associated expected production capacities; projections for 2017 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; our future opportunities for oil development; forecast operating and financial results, including forecast sales prices, costs and cash flows; targets for our Debt to Capitalization and Debt to Adjusted EBITDA ratios; our ability to satisfy payment obligations as they become due; planned capital expenditures, including the amount, timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves; capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; our priorities for 2017; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices, derivative financial instruments, foreign exchange rates, the Acquisition, British Columbia exposure, the Bought-Deal Common Share Offering and the U.S. federal administration; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof by Cenovus, and anticipated impact on the Consolidated Balance Sheets; anticipated use of proceeds of the Bought-Deal Common Share Offering and the Note Offering; expected completion of the Acquisition, including the timing thereof; the availability and repayment of the existing credit facility and the Bridge Facility; potential asset sales and anticipated use of sales proceeds; expected impacts of the contingent payment agreement; future use and development of technology; our ability to access and implement all technology necessary to efficiently and effectively operate our assets (including, but not limited to, the acquired assets) and achieve and sustain future cost reductions; projected growth and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2017 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; successful completion of the Acquisition, including timing and availability of all required financing; our ability to successfully integrate the Deep Basin Assets; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans associated with 100% ownership of FCCL; our ability to complete asset sales, including with desired transaction metrics; the anticipated impact of the Acquisition and related financing on Cenovus's credit ratings; forecast crude oil and natural gas prices, forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment agreement; alignment of realized Western Canadian Select ("WCS") prices and WCS prices as calculated under the contingent payment agreement; our projected capital investment levels, the flexibility of capital spending plans and the associated sources of funding; sustainability of achieved cost reductions, achievement of further cost reductions and sustainability thereof, including, but not limited to, in relation to the acquired assets; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and NGLs from properties and other sources not currently classified as proved; future use and development of technology; our ability to access and implement all technology necessary to efficiently and effectively operate our assets (including, but not limited to, the acquired assets) and achieve and sustain cost reductions; our ability to implement capital projects or stages thereof in a successful and timely manner; 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.

2017 guidance, as updated on December 8, 2016, assumes: Brent prices of US$48.75/bbl, WTI prices of US$47.25/bbl; WCS of US$31.50/bbl; NYMEX natural gas prices of US$3.00/MMBtu; AECO natural gas prices of $2.60/GJ; Chicago 3-2-1 crack spread of US$11.25/bbl; and an exchange rate of $0.74 US$/C$.

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

The risk factors and uncertainties that could cause our actual results to differ materially, include: possible failure by us to realize the anticipated benefits of and synergies from the Acquisition; our inability to complete the Acquisition on the terms contemplated by the purchase and sale agreement between Cenovus and ConocoPhillips or at all; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets (including, but not limited to, the acquired assets) and achieve and sustain future cost reductions; volatility of and other assumptions regarding commodity 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; possible lack of alignment of realized WCS prices and WCS prices as calculated under the contingent payment agreement; 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 the operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Debt (and Net Debt) to Adjusted EBITDA as well as Debt (and Net Debt) to Capitalization; 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, future production and future net revenue estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost-effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward looking information. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the period ended December 31, 2016, available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com, and the updates under "Risk Management" in this MD&A.

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.

NETBACK RECONCILIATIONS

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

Total Crude Oil, NGLs and Natural Gas

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation: Crude Oil & NGLs	Basis of Netback Calculation: Natural Gas	Basis of Netback Calculation: Total	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Interim Consolidated Financial Statements (1): Other Products	Per Interim Consolidated Financial Statements (1): Total Upstream
Revenues								
Gross Sales	**823**	**97**	**920**	**511**	**-**	**1**	**4**	**1,436**
Less: Royalties	**73**	**4**	**77**	**-**	**-**	**-**	**-**	**77**
	750	**93**	**843**	**511**	**-**	**1**	**4**	**1,359**
Expenses								
Transportation and Blending	**102**	**4**	**106**	**511**	**-**	**-**	**-**	**617**
Operating	**205**	**44**	**249**	**-**	**-**	**-**	**1**	**250**
Production and Mineral Taxes	**4**	**1**	**5**	**-**	**-**	**-**	**-**	**5**
Netback	**439**	**44**	**483**	**-**	**-**	**1**	**3**	**487**
(Gain) Loss on Risk Management	**90**	**-**	**90**	**-**	**-**	**-**	**-**	**90**
Operating Margin	**349**	**44**	**393**	**-**	**-**	**1**	**3**	**397**

Three Months Ended March 31, 2016 ($ millions)	Basis of Netback Calculation: Crude Oil & NGLs	Basis of Netback Calculation: Natural Gas	Basis of Netback Calculation: Total	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Interim Consolidated Financial Statements (1): Other Products	Per Interim Consolidated Financial Statements (1): Total Upstream
Revenues								
Gross Sales	291	85	376	363	-	1	4	**744**
Less: Royalties	17	3	20	-	-	-	-	**20**
	274	82	356	363	-	1	4	**724**
Expenses								
Transportation and Blending	107	3	110	363	(22)	-	-	**451**
Operating	202	46	248	-	-	(3)	4	**249**
Production and Mineral Taxes	2	-	2	-	-	-	-	**2**
Netback	(37)	33	(4)	-	22	4	-	**22**
(Gain) Loss on Risk Management	(148)	-	(148)	-	-	3	-	**(145)**
Operating Margin	111	33	144	-	22	1	-	**167**

Total Crude Oil and NGLs

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation: Crude Oil	Basis of Netback Calculation: NGLs	Basis of Netback Calculation: Total	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Interim Consolidated Financial Statements (1): Total Crude Oil & NGLs
Revenues							
Gross Sales	**818**	**5**	**823**	**511**	**-**	**-**	**1,334**
Less: Royalties	**72**	**1**	**73**	**-**	**-**	**-**	**73**
	746	**4**	**750**	**511**	**-**	**-**	**1,261**
Expenses							
Transportation and Blending	**102**	**-**	**102**	**511**	**-**	**-**	**613**
Operating	**205**	**-**	**205**	**-**	**-**	**-**	**205**
Production and Mineral Taxes	**4**	**-**	**4**	**-**	**-**	**-**	**4**
Netback	**435**	**4**	**439**	**-**	**-**	**-**	**439**
(Gain) Loss on Risk Management	**90**	**-**	**90**	**-**	**-**	**-**	**90**
Operating Margin	**345**	**4**	**349**	**-**	**-**	**-**	**349**

Three Months Ended March 31, 2016 ($ millions)	Basis of Netback Calculation: Crude Oil	Basis of Netback Calculation: NGLs	Basis of Netback Calculation: Total	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Interim Consolidated Financial Statements (1): Total Crude Oil & NGLs
Revenues							
Gross Sales	288	3	291	363	-	-	**654**
Less: Royalties	17	-	17	-	-	-	**17**
	271	3	274	363	-	-	**637**
Expenses							
Transportation and Blending	107	-	107	363	(22)	-	**448**
Operating	202	-	202	-	-	(2)	**200**
Production and Mineral Taxes	2	-	2	-	-	-	**2**
Netback	(40)	3	(37)	-	22	2	**(13)**
(Gain) Loss on Risk Management	(148)	-	(148)	-	-	2	**(146)**
Operating Margin	108	3	111	-	22	-	**133**

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

Oil Sands Crude Oil

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Adjustments: Condensate	Inventory	Per Interim Consolidated Financial Statements (1): Total Oil Sands Crude Oil
Revenues						
Gross Sales	**287**	**290**	**577**	**478**	**-**	**1,055**
Less: Royalties	**20**	**7**	**27**	**-**	**-**	**27**
	267	**283**	**550**	**478**	**-**	**1,028**
Expenses						
Transportation and Blending	**55**	**33**	**88**	**478**	**-**	**566**
Operating	**71**	**65**	**136**	**-**	**-**	**136**
Netback	**141**	**185**	**326**	**-**	**-**	**326**
(Gain) Loss on Risk Management	**40**	**37**	**77**	**-**	**-**	**77**
Operating Margin	**101**	**148**	**249**	**-**	**-**	**249**

Three Months Ended March 31, 2016 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Adjustments: Condensate	Inventory	Per Interim Consolidated Financial Statements (1): Total Oil Sands Crude Oil
Revenues						
Gross Sales	65	65	130	335	-	**465**
Less: Royalties	-	-	-	-	-	**-**
	65	65	130	335	-	**465**
Expenses						
Transportation and Blending	48	39	87	335	(18)	**404**
Operating	67	55	122	-	-	**122**
Netback	(50)	(29)	(79)	-	18	**(61)**
(Gain) Loss on Risk Management	(52)	(54)	(106)	-	-	**(106)**
Operating Margin	2	25	27	-	18	**45**

Conventional Crude Oil and NGLs

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Crude Oil & NGLs	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements(1): Total Conventional Crude Oil & NGLs
Revenues								
Gross Sales	**113**	**128**	**5**	**246**	**33**	**-**	**-**	**279**
Less: Royalties	**16**	**29**	**1**	**46**	**-**	**-**	**-**	**46**
	97	**99**	**4**	**200**	**33**	**-**	**-**	**233**
Expenses								
Transportation and Blending	**8**	**6**	**-**	**14**	**33**	**-**	**-**	**47**
Operating	**31**	**38**	**-**	**69**	**-**	**-**	**-**	**69**
Production and Mineral Taxes	**-**	**4**	**-**	**4**	**-**	**-**	**-**	**4**
Netback	**58**	**51**	**4**	**113**	**-**	**-**	**-**	**113**
(Gain) Loss on Risk Management	**7**	**6**	**-**	**13**	**-**	**-**	**-**	**13**
Operating Margin	**51**	**45**	**4**	**100**	**-**	**-**	**-**	**100**

Three Months Ended March 31, 2016 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Crude Oil & NGLs	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Conventional Crude Oil & NGLs
Revenues								
Gross Sales	73	85	3	161	28	-	-	**189**
Less: Royalties	4	13	-	17	-	-	-	**17**
	69	72	3	144	28	-	-	**172**
Expenses								
Transportation and Blending	13	7	-	20	28	(4)	-	**44**
Operating	40	40	-	80	-	-	(2)	**78**
Production and Mineral Taxes	-	2	-	2	-	-	-	**2**
Netback	16	23	3	42	-	4	2	**48**
(Gain) Loss on Risk Management	(22)	(20)	-	(42)	-	-	2	**(40)**
Operating Margin	38	43	3	84	-	4	-	**88**

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

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

Sales Volumes

	Three Months Ended March 31,	
(barrels per day, unless otherwise stated)	**2017**	2016
Oil Sands		
Foster Creek	**78,562**	60,169
Christina Lake	**89,919**	80,118
	168,481	140,287
Conventional		
Heavy Oil	**26,222**	30,764
Light and Medium Oil	**25,074**	27,210
Natural Gas Liquids ("NGLs")	**1,047**	1,208
	52,343	59,182
Crude Oil and NGLs Sales	**220,824**	199,469
Natural Gas Sales (MMcf per day)	**363**	408
Total Sales (BOE per day)	**281,324**	267,469