MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2016

WHERE TO FIND:

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 February 15, 2017, should be read in conjunction with our December 31, 2016 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 15, 2017, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 15, 2017. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures 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 (previously labelled Cash Flow), Operating Earnings, Free Funds Flow (previously labelled Free Cash Flow), Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. We previously identified Operating Cash Flow, now relabelled Operating Margin, as a non-GAAP measure; however, Operating Margin is an additional subtotal found in Note 1 of our Consolidated Financial Statements, and therefore we no longer identify it as a non-GAAP measure.

The relabelling of Operating Cash Flow to Operating Margin and Cash Flow to Adjusted Funds Flow was based on recently published regulatory guidance. 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 December 31, 2016, we had a market capitalization of approximately $17 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in 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 in 2016 was approximately 205,860 barrels per day and our average natural gas production was 394 MMcf per day. The refining operations processed an average of 444,000 gross barrels per day of crude oil feedstock into an average of 471,000 gross barrels per day of refined products.

Our Strategy

Our strategy is to focus on generating total shareholder return as a low cost energy producer in North America through our strategic differentiators: premium asset quality, disciplined manufacturing, value-added integration, focused innovation, and trusted reputation.

Premium Quality Assets

We have a portfolio of premium-quality oil sands, conventional, and refining and marketing assets. We plan to add value by investing in prudent and focused growth at our producing oil sands projects, notably Foster Creek and Christina Lake, while focusing our innovation efforts to achieve step-change reductions in costs for future oil sands projects. Oil sands growth will be complemented by investment in select low-cost and short-cycle time conventional opportunities that are well-suited to responding to changes in macro conditions.

Our producing asset mix includes:

- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs.

Our marketing, products and transportation activities include:

- Refining oil into various products to reduce the impact of commodity price fluctuations;
- Creating a variety of oil blends to help maximize our transportation and refining options; and
- Accessing new markets that will position us to achieve the best pricing for our oil.

Disciplined Manufacturing

We continue to focus on executing our business plan in a predictable and reliable way and are committed to developing our resources safely and responsibly. The manufacturing approach we use to produce crude oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs and improve productivity and efficiencies at every phase of our oil sands projects. This approach incorporates learnings from previous phases into future growth plans. Manufacturing principles will be deployed for each area of our business to balance innovation, agility, cost focus and efficiency.

Value-Added Integration

Our integrated business approach positions us to capture the full value chain from production to high-quality end products like transportation fuels. This helps provide stability to our cash flows and maximize value for every barrel of oil we produce.

Focused Innovation

Our focused innovation is aimed at enabling Cenovus to be a low-cost and environmentally-responsible energy producer. Our innovation efforts are focused on initiatives intended to increase recoveries from our reservoirs, improve cycle times and margins, and enhance environmental performance. We plan to build on our track record of developing innovative solutions that unlock challenging crude oil resources and plan to work to commercialize successful technologies through continued investment as well as global partnerships that will bring smart minds, funds and third-party advocates together.

Trusted Reputation

We are committed to providing a safe and healthy workplace, building strong relationships with stakeholders, and minimizing our environmental footprint. Our actions support our trusted reputation.

Financial Strength

Maintaining a strong balance sheet is necessary to execute our strategy. To help protect our financial flexibility, we will focus on maximizing cost efficiencies and maintaining our financial resilience. We anticipate our total annual capital investment for 2017 to be between $1.2 billion and $1.4 billion, approximately 30 percent higher than in 2016. While we anticipate crude oil prices will continue to be volatile in 2017, sustainable cost reductions achieved over the last two years provide us the flexibility to consider advancing certain projects. At December 31, 2016, we had $3.7 billion of cash on hand, $4.0 billion of undrawn capacity under our committed credit facility, and no debt maturing until the fourth quarter of 2019.

Dividend

In 2016, we paid a dividend of $0.20 per share compared with $0.8524 per share in 2015. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

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-owned) with ConocoPhillips, an unrelated U.S. public company. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions of northeastern Alberta, respectively.

	2016	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Margin	**875**	**4**
Capital Investment	**601**	**3**
Operating Margin Net of Related Capital Investment	**274**	**1**

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.

	2016	
($ millions)	**Crude Oil** (1)	**Natural Gas**
Operating Margin	**402**	**137**
Capital Investment	**161**	**10**
Operating Margin Net of Related Capital Investment	**241**	**127**

(1) Includes NGLs.

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, Saskatchewan and emerging tight oil assets in Alberta.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company.

	2016	
	Ownership Interest (percent)	**Gross Nameplate Capacity** (Mbbls/d)
Wood River	**50**	**314**
Borger	**50**	**146**

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)	**2016**
Operating Margin	**346**
Capital Investment	**220**
Operating Margin Net of Related Capital Investment	**126**

2016 HIGHLIGHTS

In 2016, our financial results continued to be significantly impacted by volatile crude oil prices. In the first quarter of 2016, the West Texas Intermediate ("WTI") benchmark price reached a low of US$26.05 per barrel, before gradually strengthening to close the year at US$53.72 per barrel. Our companywide Netback of $11.33 per BOE for 2016, before realized risk management activities, was considerably lower than in prior years.

As a result of the continued price volatility, we focused on delivering value through preserving financial resilience, exercising capital discipline and achieving sustained cost reductions, while delivering safe and reliable operating performance. We exited the year with a strong balance sheet with over $3.7 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility.

In 2016, we:

- Achieved Cash From Operating Activities and Adjusted Funds Flow of $861 million and $1,423 million, respectively. Declines from 2015 were primarily due to a decrease in realized risk management gains and lower commodity prices, partially offset by lower operating costs;
- Incurred a Net Loss of $545 million compared with Net Earnings of $618 million in 2015 primarily due to an after-tax gain in 2015 of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business;
- Decreased total crude oil operating costs by $1.63 per barrel, or 14 percent compared with 2015;
- Invested $1,026 million in capital, a 40 percent reduction from 2015;
- Added incremental crude oil production volumes from Foster Creek phase G and Christina Lake phase F. Start-up of these phases, which includes cogeneration at Christina Lake phase F, added 80,000 gross barrels per day of production capacity and approximately 100 gross megawatts of electrical generation capacity;
- Increased proved bitumen reserves by seven percent primarily due to the area expansion at Christina Lake;
- Successfully completed the debottlenecking project at the Wood River refinery; and
- Reduced our annual dividend from $0.8524 per share in 2015 to $0.20 per share.

OPERATING RESULTS

Our upstream assets continued to perform well in 2016. Total crude oil production remained relatively consistent as higher production from our Oil Sands segment was offset by lower production from our Conventional properties.

Crude Oil Production Volumes

(barrels per day)	**2016**	**Percent Change**	2015	Percent Change	2014
Oil Sands					
Foster Creek	**70,244**	**7%**	65,345	10%	59,172
Christina Lake	**79,449**	**6%**	74,975	9%	69,023
	149,693	**7%**	140,320	9%	128,195
Conventional					
Heavy Oil	**29,185**	**(16)%**	34,888	(12)%	39,546
Light and Medium Oil	**25,915**	**(15)%**	30,486	(12)%	34,531
NGLs [(1)]	**1,065**	**(15)%**	1,253	3%	1,221
	56,165	**(16)%**	66,627	(12)%	75,298
Total Crude Oil Production	**205,858**	**(1)%**	206,947	2%	203,493

(1) NGLs include condensate volumes.

In 2016, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion and additional wells being brought online. Ramp-up of phase G has progressed well and is now expected to take 12 months from start-up, which occurred early in the third quarter of 2016. In the second quarter of 2015, a nearby forest fire temporarily shut down operations and decreased full year production by approximately 2,600 barrels per day.

Production from Christina Lake increased compared with 2015 due to the start-up of the phase F expansion and the related increase in wells brought online, incremental production from the optimization project completed in 2015, and reliable performance of our facilities. Ramp-up of phase F began in the fourth quarter and is expected to take 12 months from start-up.

Our Conventional crude oil production decreased from 2015 due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in July 2015. Divested assets contributed 2,555 barrels per day in 2015. Production also decreased in 2016 due to reduced capital investment.

Natural Gas Production Volumes

(MMcf per day)	**2016**	2015	2014
Conventional	**377**	422	466
Oil Sands	**17**	19	22
	394	441	488

Our natural gas production was 11 percent lower in 2016. Production decreased due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015.

Oil and Gas Reserves

Based on our reserves report prepared by independent qualified reserves evaluators ("IQREs"), our proved bitumen reserves increased seven percent to approximately 2.3 billion barrels and our proved plus probable bitumen reserves rose slightly to approximately 3.3 billion barrels. Additional information about our reserves and resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

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. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. 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 ("COGE Handbook").

	Crude Oil (1) ($/bbl)			**Natural Gas** ($/Mcf)		
	2016	2015	2014	**2016**	2015	2014
Sales Price	**31.20**	35.38	71.35	**2.32**	2.92	4.37
Royalties	**1.79**	1.75	6.18	**0.10**	0.07	0.08
Transportation and Blending	**5.81**	5.48	2.98	**0.11**	0.11	0.12
Operating Expenses	**10.35**	11.98	15.40	**1.15**	1.20	1.22
Production and Mineral Taxes	**0.16**	0.22	0.50	**-**	0.01	0.05
Netback Excluding Realized Risk Management (2)	**13.09**	15.95	46.29	**0.96**	1.53	2.90
Realized Risk Management Gain (Loss)	**3.23**	7.51	0.50	**-**	0.37	0.04
Netback Including Realized Risk Management	**16.32**	23.46	46.79	**0.96**	1.90	2.94

(1) *Includes NGLs.*
(2) *Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.*

Our average crude oil Netback in 2016, excluding realized risk management gains and losses, decreased compared with 2015. Lower sales prices, consistent with the decline in benchmark prices, were partially offset by a decrease in operating costs and the weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar compared with 2015 had a positive impact on our crude oil price of approximately $1.09 per barrel.

In 2016, our average natural gas Netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the decline in the AECO benchmark price.

Refining and Marketing

In the third quarter of 2016, the Wood River debottlenecking project was successfully completed. Strong operational performance in 2016 resulted in higher crude oil runs and refined product output, which helped to partially offset the decline in our Refining and Marketing Operating Margin. The decline in Operating Margin was primarily due to lower average market crack spreads.

	2016	**Percent Change**	2015	Percent Change	2014
Crude Oil Runs (1) (Mbbls/d)	**444**	**6%**	419	(1)%	423
Heavy Crude Oil (1)	**233**	**17%**	200	1%	199
Refined Product (1) (Mbbls/d)	**471**	**6%**	444	-%	445
Crude Utilization (1) (percent)	**97**	**6%**	91	(1)%	92

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

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

	Q4 2016	Q4 2015	**2016**	2015	**Percent Change**	2014
Crude Oil Prices (US$/bbl)						
Brent						
Average	**51.13**	44.71	**45.04**	53.64	**(16)%**	99.51
End of Period	**56.82**	37.28	**56.82**	37.28	**52%**	57.33
WTI						
Average	**49.29**	42.18	**43.32**	48.80	**(11)%**	93.00
End of Period	**53.72**	37.04	**53.72**	37.04	**45%**	53.27
Average Differential Brent-WTI	**1.84**	2.53	**1.72**	4.84	**(64)%**	6.51
WCS (2)						
Average	**34.97**	27.69	**29.48**	35.28	**(16)%**	73.60
End of Period	**38.81**	24.98	**38.81**	24.98	**55%**	37.59
Average Differential WTI-WCS	**14.32**	14.49	**13.84**	13.52	**2%**	19.40
Condensate (C5 @ Edmonton) (3)						
Average	**48.33**	41.67	**42.47**	47.36	**(10)%**	92.95
Average Differential WTI-Condensate (Premium)/Discount	**0.96**	0.51	**0.85**	1.44	**(41)%**	0.05
Average Differential WCS-Condensate (Premium)/Discount	**(13.36)**	(13.98)	**(12.99)**	(12.08)	**8%**	(19.35)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**59.46**	55.24	**56.24**	67.68	**(17)%**	107.40
Chicago Ultra-low Sulphur Diesel ("ULSD")	**61.50**	59.23	**56.33**	68.12	**(17)%**	117.55
Refining Margin: Average 3-2-1 Crack Spread (4) (US$/bbl)						
Chicago	**10.96**	14.47	**13.07**	19.11	**(32)%**	17.61
Average Natural Gas Prices						
AECO (C$/Mcf)	**2.81**	2.65	**2.09**	2.77	**(25)%**	4.42
NYMEX (US$/Mcf)	**2.98**	2.27	**2.46**	2.66	**(8)%**	4.42
Basis Differential NYMEX-AECO (US$/Mcf)	**0.86**	0.27	**0.89**	0.49	**82%**	0.40
Foreign Exchange Rates (US$ per C$1)						
Average	**0.750**	0.749	**0.755**	0.782	**(3)%**	0.905

(1) These benchmark prices do not reflect our sales prices. For our average 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 WCS benchmark price for 2016 was $39.05 per barrel (2015 – $45.12 per barrel; 2014 – $81.33 per barrel); fourth quarter average WCS benchmark price was $46.63 per barrel (2015 – $36.97 per barrel).
(3) The average Canadian dollar condensate benchmark price for 2016 was $56.25 per barrel (2015 – $60.56 per barrel; 2014 – $102.71 per barrel); fourth quarter average condensate benchmark price was $64.44 per barrel (2015 – $55.63 per barrel).
(4) The Average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

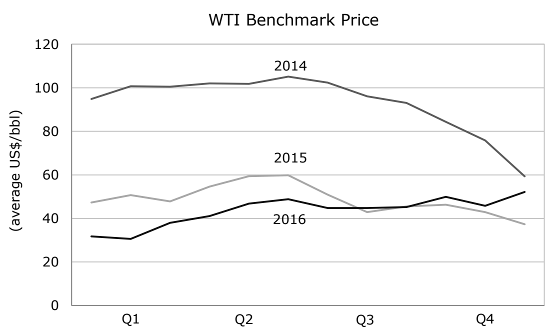
Crude Oil Benchmarks

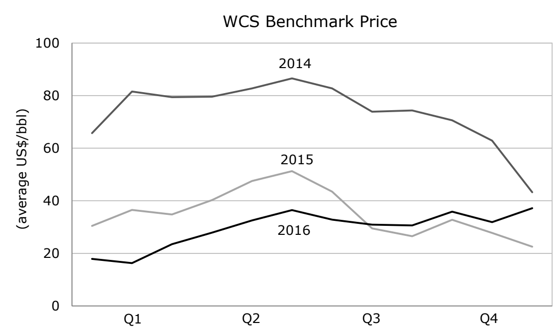
Average WTI declined US$5.48 per barrel in 2016 compared with 2015 as a result of excess crude oil and refined product inventories. Overall, average crude oil benchmark prices in 2016 continued to be volatile. We saw a steep decline in crude oil prices in the first quarter, with the WTI benchmark price falling as low as US$26.05 per barrel. A gradual recovery occurred over the remainder of the year and WTI closed at US$53.72 per barrel. Prices were boosted in November 2016 as the Organization of Petroleum Exporting Countries ("OPEC"), along with select non-OPEC countries, such as Russia, reached an agreement to reduce production. As a result, average crude oil benchmark prices in the fourth quarter of 2016 improved 18 percent compared with the same period in 2015. 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.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was slightly wider in 2016 compared with 2015 as additional U.S. imports of medium crude oil competed for refining capacity, and heavy oil prices were pressured by an oversupply of heavy oil products, such as fuel oil and bunker fuel.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range between 10 percent and 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. Since the supply of condensate in Alberta does not meet 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 2016 compared with 2015. Declining U.S. light oil production reduced condensate supply from the U.S. Gulf Coast while higher heavy oil production in Alberta increased demand. However, in the second quarter of 2016, the Alberta forest fires reduced heavy oil production and the associated demand for diluent.

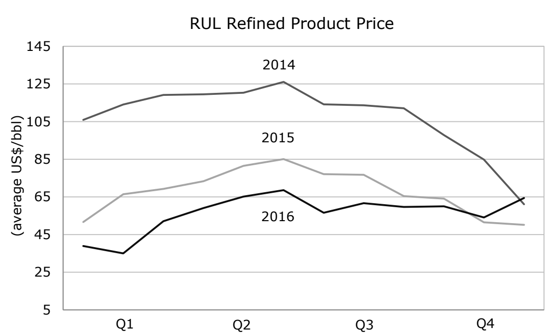


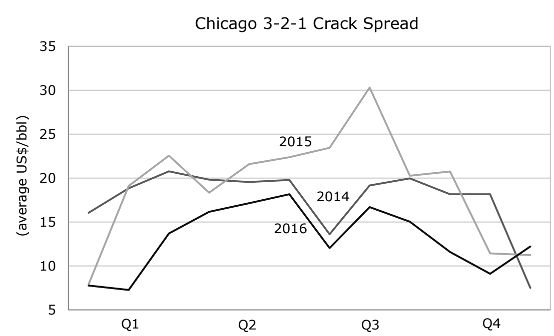


Refining Benchmarks

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

Average Chicago 3-2-1 crack spreads decreased in 2016 compared with 2015 due to higher global refined product inventory, and strengthening of the WTI benchmark price compared with Brent due to the lifting of the U.S. export ban. 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 decreased in 2016 compared with 2015 primarily due to high inventory levels in North America given a warmer than normal 2015/2016 winter and stable North American supply.

Foreign Exchange Benchmarks

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In 2016 compared with 2015, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and strengthening of the U.S. economy. The weakening of the Canadian dollar in 2016 had a positive impact of approximately $422 million on our revenues. The Canadian dollar at December 31, 2016 compared with December 31, 2015 was three percent stronger, resulting in $196 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

Volatile commodity prices in 2016 impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	**2016**	**Percent Change**	2015	Percent Change	2014
Revenues	**12,134**	**(7)%**	13,064	(33)%	19,642
Operating Margin [1]	**1,767**	**(28)%**	2,439	(42)%	4,179
Cash From Operating Activities	**861**	**(42)%**	1,474	(58)%	3,526
Adjusted Funds Flow [2]	**1,423**	**(16)%**	1,691	(51)%	3,479
Operating Earnings (Loss) [2]	**(377)**	**6%**	(403)	(164)%	633
Per Share – Diluted	**(0.45)**	**8%**	(0.49)	(158)%	0.84
Net Earnings (Loss)	**(545)**	**(188)%**	618	(17)%	744
Per Share – Basic and Diluted ($)	**(0.65)**	**(187)%**	0.75	(23)%	0.98
Total Assets	**25,258**	**(2)%**	25,791	4%	24,695
Total Long-Term Financial Liabilities [3]	**6,373**	**(2)%**	6,552	19%	5,484
Capital Investment [4]	**1,026**	**(40)%**	1,714	(44)%	3,051
Dividends					
Cash Dividends	**166**	**(69)%**	528	(34)%	805
In Shares From Treasury	**-**	**-**	182	-	-
Per Share ($)	**0.20**	**(77)%**	0.8524	(20)%	1.0648

(1) Additional subtotal found in Note 1 of the Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Includes Long-Term Debt, Risk Management Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(4) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

($ millions)	**2016 vs. 2015**	2015 vs. 2014
Revenues, Comparative Year	**13,064**	19,642
Increase (Decrease) due to:		
Oil Sands	**(81)**	(1,799)
Conventional	**(467)**	(1,401)
Refining and Marketing	**(366)**	(3,853)
Corporate and Eliminations	**(16)**	475
Revenues, End of Year	**12,134**	13,064

Combined Oil Sands and Conventional revenues declined 12 percent in 2016 compared with 2015 due to lower crude oil and natural gas sales prices and a decline in natural gas sales volumes, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues.

Revenues from our Refining and Marketing segment decreased four percent from 2015. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by higher refined product output and a weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2016 increased 23 percent from 2015, primarily due to higher purchased crude oil and natural gas volumes, and higher crude oil sales prices, partially offset by lower natural gas sales prices.

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

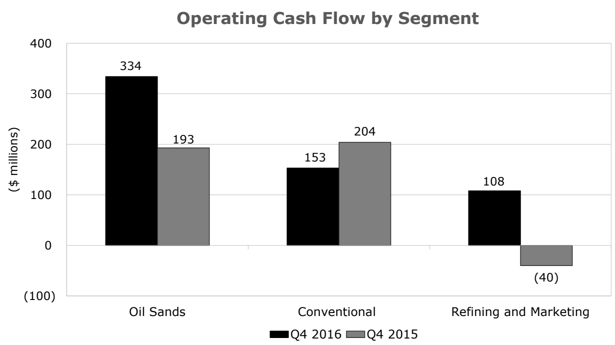
Overall, revenues decreased in 2015 compared with 2014 primarily due to lower crude oil and natural gas sales prices and a decline in refined product pricing, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar.

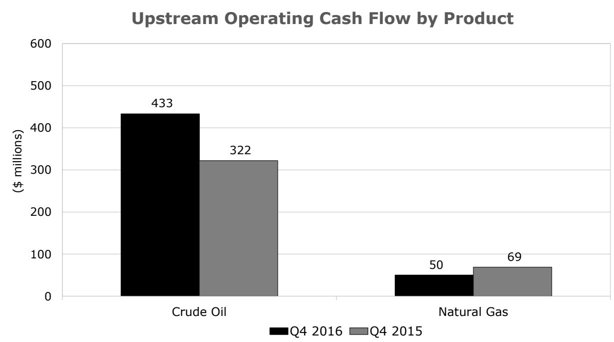
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Margin

Operating Margin is an additional subtotal found in Note 1 of the 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.

($ millions)	**2016**	2015	2014
Revenues	**12,487**	13,401	20,454
(Add) Deduct:			
Purchased Product	**7,325**	7,709	11,767
Transportation and Blending	**1,907**	2,045	2,477
Operating Expenses	**1,687**	1,846	2,051
Production and Mineral Taxes	**12**	18	46
Realized (Gain) Loss on Risk Management	**(211)**	(656)	(66)
Operating Margin	**1,767**	2,439	4,179





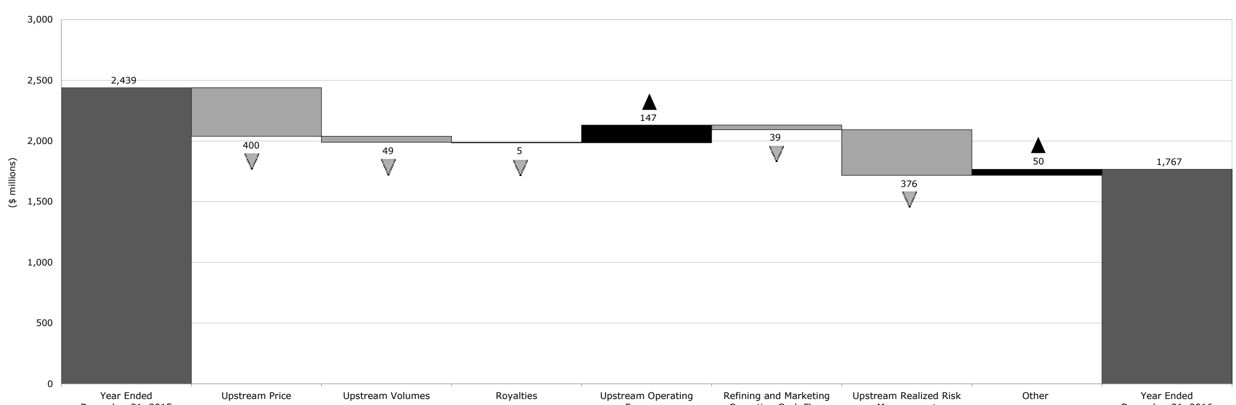
Operating Margin declined 28 percent in 2016 compared with 2015 primarily due to:

- A 12 percent decrease in our average crude oil sales price and a 21 percent reduction in our average natural gas sales price. Our average crude oil price in 2016 was significantly impacted by lower prices in the first quarter;
- Realized risk management gains of $237 million, excluding Refining and Marketing, compared with gains of $613 million in 2015;
- An 11 percent decline in our natural gas sales volumes; and
- Lower Operating Margin from Refining and Marketing as a result of lower average market crack spreads and realized risk management losses as compared with gains in 2015. This was partially offset by widening heavy and medium crude oil differentials, higher utilization rates, and weakening of the Canadian dollar relative to the U.S. dollar.

These declines to Operating Margin were partially offset by:

- A decrease of $1.63 per barrel in crude oil operating expenses primarily due to a decline in repairs and maintenance, lower chemical costs, and workforce reductions; and
- An inventory write-down of $4 million (2015 – $66 million).

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)	**2016**	2015	2014
Cash From Operating Activities	**861**	1,474	3,526
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(91)**	(107)	(135)
Net Change in Non-Cash Working Capital	**(471)**	(110)	182
Adjusted Funds Flow	**1,423**	1,691	3,479

In 2016, Cash From Operating Activities and Adjusted Funds Flow decreased primarily as a result of lower Operating Margin, as discussed above, partially offset by a cash tax recovery due to losses carried back to recover taxes previously paid and lower costs related to larger workforce reductions in 2015 as compared with 2016. The change in working capital was primarily due to the improvement of commodity prices at the end of 2016 compared with 2015, resulting in higher accounts receivable, accounts payable, and Refining and Marketing inventory values. In addition, crude oil inventory volumes rose year over year.

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)	**2016**	2015	2014
Earnings (Loss), Before Income Tax	**(927)**	537	1,195
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (1)	**554**	195	(596)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**(196)**	1,064	458
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	(156)
Operating Earnings (Loss), Before Income Tax	**(563)**	(596)	901
Income Tax Expense (Recovery)	**(186)**	(193)	268
Operating Earnings (Loss)	**(377)**	(403)	633

(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 2015 primarily due to a decline in depreciation, depletion and amortization ("DD&A"), related to lower DD&A rates and asset impairments, and a decline in exploration expense.

The lower Operating Loss was partially offset by:
- A decline in Cash From Operating Activities and Adjusted Funds Flow, as discussed above;
- A non-cash expense of $61 million for office space in excess of Cenovus's current and near-term requirements;
- Higher long-term employee incentive costs primarily due to an increase in our share price; and
- An asset impairment of $23 million and termination costs of $7 million as a result of the Government of Canada's decision to reject the Northern Gateway Pipeline project.

Refer to the Reportable Segments section for more details.

Net Earnings (Loss)

($ millions)	2016 vs. 2015	2015 vs. 2014
Net Earnings (Loss), Comparative Year	**618**	744
Increase (Decrease) due to:		
Operating Margin	**(672)**	(1,740)
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(359)**	(791)
Unrealized Foreign Exchange Gain (Loss)	**1,286**	(686)
Gain (Loss) on Divestiture of Assets	**(2,398)**	2,236
Expenses (1)	**(73)**	46
Depreciation, Depletion and Amortization	**616**	(168)
Goodwill Impairment	**-**	497
Exploration Expense	**136**	(52)
Income Tax Recovery (Expense)	**301**	532
Net Earnings (Loss), End of Year	**(545)**	618

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

In 2016, Net Earnings declined primarily due to:

- An after-tax gain in 2015 of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business;
- A lower deferred income tax recovery of $209 million (2015 – $655 million); and
- Unrealized risk management losses of $554 million (2015 – $195 million).

The decline was partially offset by non-operating unrealized foreign exchange gains of $196 million, compared with unrealized losses of $1,064 million in 2015, and a lower Operating Loss, as discussed above.

Net Earnings declined in 2015 compared with 2014 primarily due to lower Operating Earnings, larger non-operating unrealized foreign exchange losses, and unrealized risk management losses compared with gains in 2014. These declines were partially offset by the gain from the divestiture of our royalty interest and mineral fee title lands business in 2015.

Net Capital Investment

($ millions)	2016	2015	2014
Oil Sands	**604**	1,185	1,986
Conventional	**171**	244	840
Refining and Marketing	**220**	248	163
Corporate and Eliminations	**31**	37	62
Capital Investment	**1,026**	1,714	3,051
Acquisitions	**11**	87	18
Divestitures	**(8)**	(3,344)	(277)
Net Capital Investment (1)	**1,029**	(1,543)	2,792

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

Capital investment in 2016 declined 40 percent compared with 2015 as we reduced our spending in light of the low commodity price environment. Oil Sands capital investment focused primarily on sustaining capital related to existing production, as well as completing the facilities at Foster Creek phase G and Christina Lake phase F. Conventional capital investment focused on drilling stratigraphic test wells for tight oil, maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment in the Refining and Marketing segment focused on completion of the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives.

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

Acquisitions and Divestitures

We had no significant acquisitions or divestitures in 2016. In 2015, we completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion, recording an after-tax gain of approximately $1.9 billion. The sale included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on Cenovus's working interest production on these fee lands and a gross overriding royalty on production from our Pelican Lake and Weyburn assets were also included. In 2015, we also purchased a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options. In 2014, divestitures included the sale of certain of our Bakken assets in southeastern Saskatchewan and certain of our Wainwright assets in Alberta for net proceeds of $269 million.

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)	2016	2015	2014
Adjusted Funds Flow [(1)]	**1,423**	1,691	3,479
Capital Investment (Sustaining and Growth)	**1,026**	1,714	3,051
Free Funds Flow [(2)]	**397**	(23)	428
Cash Dividends	**166**	528	805
	231	(551)	(377)

(1) Non-GAAP measure defined in this MD&A.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We expect our capital investment for 2017 to be funded from internally generated cash flows and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

Revenues by Reportable Segment

($ millions)	2016	2015	2014
Oil Sands	**2,920**	3,001	4,800
Conventional	**1,128**	1,595	2,996
Refining and Marketing	**8,439**	8,805	12,658
Corporate and Eliminations	**(353)**	(337)	(812)
	12,134	13,064	19,642

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of development, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant developments that impacted our Oil Sands segment in 2016 compared with 2015 include:

- Reducing our crude oil operating costs by $1.22 per barrel, a 12 percent decline;
- Crude oil Netbacks, excluding realized risk management activities, of $11.94 per barrel (2015 – $13.53 per barrel);
- Generating Operating Margin net of capital investment of $273 million, an increase of $399 million;
- Reducing capital investment by $581 million, or 49 percent compared with 2015; and
- Adding incremental crude oil production volumes from Foster Creek phase G and Christina Lake phase F. Start-up of these expansion phases, which includes cogeneration at Christina Lake phase F, added 80,000 gross barrels per day of production capacity and approximately 100 gross megawatts of electrical generation capacity.

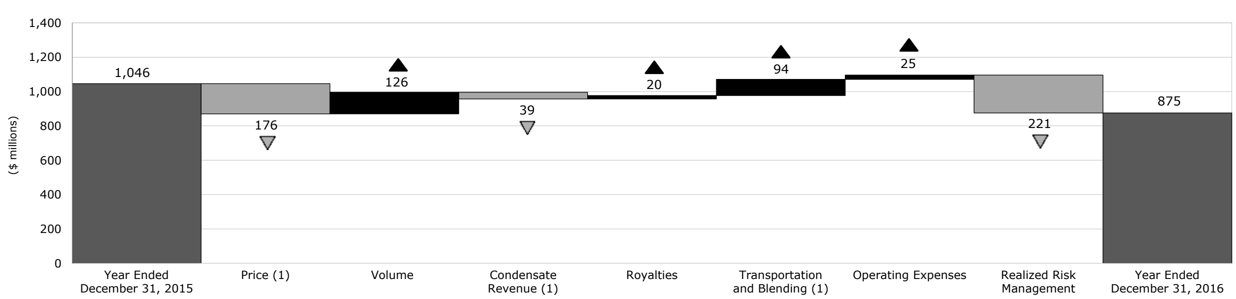
Oil Sands – Crude Oil

Financial Results

($ millions)	2016	2015	2014
Gross Sales	**2,911**	3,000	4,963
Less: Royalties	**9**	29	233
Revenues	**2,902**	2,971	4,730
Expenses			
Transportation and Blending	**1,720**	1,814	2,130
Operating	**486**	511	615
(Gain) Loss on Risk Management	**(179)**	(400)	(38)
Operating Margin	**875**	1,046	2,023
Capital Investment	**601**	1,184	1,980
Operating Margin Net of Related Capital Investment	**274**	(138)	43

In 2015, capital investment in excess of Operating Margin from Oil Sands was funded through Operating Margin generated by our Conventional and Refining and Marketing segments.

Operating Margin Variance



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

Revenues

Pricing

In 2016, our average crude oil sales price was $27.64 per barrel, a 10 percent decrease from 2015. Our first quarter crude oil sales price was approximately $20.50 per barrel to $26.50 per barrel lower than our average quarterly sales prices for the remainder of 2016, and significantly impacted our 2016 average price. The decline in our crude oil sales price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar and a decline in the cost of condensate.

Our bitumen 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 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 14 percent to a discount of US$2.05 per barrel (2015 – a discount of US$2.37 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In 2016, 88 percent of our Christina Lake production was sold as CDB (2015 – 86 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	**2016**	**Percent Change**	2015	Percent Change	2014
Foster Creek	**70,244**	**7%**	65,345	10%	59,172
Christina Lake	**79,449**	**6%**	74,975	9%	69,023
	149,693	**7%**	140,320	9%	128,195

In 2016, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion, and additional wells being brought online. Ramp-up of phase G has progressed well and is now expected to take 12 months from start-up, which occurred early in the third quarter of 2016. In the second quarter of 2015, a nearby forest fire temporarily shut down operations and decreased full year production by approximately 2,600 barrels per day.

Production from Christina Lake increased compared with 2015 due to the start-up of the phase F expansion and the related increase in wells brought online, incremental production from the optimization project completed in 2015, and reliable performance of our facilities. Ramp-up of phase F began in the fourth quarter and is expected to take 12 months from start-up.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential in 2016, the proportion of the cost of recovered condensate decreased.

Royalties

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

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The royalty calculation was based on gross revenues in 2016 and 2015.

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)	**2016**	2015	2014
Foster Creek	**-**	1.9	8.8
Christina Lake	**1.6**	2.8	7.5

Royalties decreased $20 million compared with 2015. At Foster Creek, the royalty rate declined in 2016 due to low crude oil sales prices, a decline in the WTI benchmark price (which determines the royalty rate), and a credit associated with the revision of prior period royalty calculations, related to the inclusion of additional employee costs and a 2015 true-up. In 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation. Excluding the prior year credits, the effective royalty rate in 2016 and 2015 for Foster Creek would have been 1.3 percent and 3.1 percent, respectively. The Christina Lake royalty rate decreased in 2016 as a result of the decline in the WTI benchmark price and lower sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $94 million in 2016. Blending costs declined due to lower condensate prices, partially offset by higher condensate volumes. In 2015, we recorded a $44 million write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. There was no inventory write-down in 2016. Our condensate costs exceeded the average benchmark price in 2016 primarily due to the transportation costs associated with moving the condensate from the purchase point to our oil sands projects.

Transportation costs increased primarily due to higher production. The proportion of sales shipped to the U.S. in 2016 was consistent with 2015. Sales to the U.S. market incur additional tariff charges, but generally secure a higher sales price. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Production growth is expected to reduce our per-barrel transportation costs.

Transportation costs related to rail decreased, despite moving higher volumes, as we transported volumes across shorter distances. We transported an average of 4,906 barrels per day of crude oil by rail (2015 – 3,529 barrels per day).

Operating

Primary drivers of our operating expenses for 2016 were workforce, fuel, workovers, chemical costs, and repairs and maintenance. Total operating expenses decreased $25 million or $1.22 per barrel, primarily as a result of a decline in repairs and maintenance activities, workforce reductions, and a decrease in chemical costs.

Per-unit Operating Expenses

($/bbl)	**2016**	**Percent Change**	2015	Percent Change	2014
Foster Creek					
Fuel	**2.46**	**(12)%**	2.80	(37)%	4.46
Non-fuel	**8.09**	**(17)%**	9.80	(18)%	11.89
Total	**10.55**	**(16)%**	12.60	(23)%	16.35
Christina Lake					
Fuel	**2.08**	**(5)%**	2.20	(40)%	3.65
Non-fuel	**5.40**	**(7)%**	5.81	(22)%	7.44
Total	**7.48**	**(7)%**	8.01	(28)%	11.09
Total	**8.91**	**(12)%**	10.13	(25)%	13.50

At Foster Creek, fuel costs decreased primarily due to the decline in natural gas prices, partially offset by an increase 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:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Workforce reductions; and
- Lower fluid, waste handling and trucking costs due to reduced maintenance activity levels.

At Christina Lake, fuel costs declined due to lower natural gas prices, partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased on a per-barrel basis primarily due to higher production and lower chemical costs due to supply chain initiatives. These decreases were offset by turnaround activities and higher workover costs due to more pump changes.

Netbacks (1)

	Foster Creek			Christina Lake		
($/bbl)	**2016**	2015	2014	**2016**	2015	2014
Sales Price (2)	**30.32**	33.65	69.43	**25.30**	28.45	61.57
Royalties	**(0.01)**	0.47	5.95	**0.33**	0.67	4.40
Transportation and Blending (2)	**8.84**	8.84	1.98	**4.68**	4.72	3.53
Operating Expenses	**10.55**	12.60	16.35	**7.48**	8.01	11.09
Netback Excluding Realized Risk Management (3)	**10.94**	11.74	45.15	**12.81**	15.05	42.55
Realized Risk Management Gain (Loss)	**3.51**	8.60	1.39	**3.08**	7.33	0.36
Netback Including Realized Risk Management	**14.45**	20.34	46.54	**15.89**	22.38	42.91

(1) Non-GAAP measure defined in this MD&A. Refer to the Operating Results section of this MD&A for details.
(2) Sales price and transportation and blending costs exclude the cost of purchased condensate, which is blended with the heavy oil.
(3) Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.

Risk Management

Risk management activities in 2016 resulted in realized gains of $179 million (2015 – $400 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2016, net of internal usage, was 17 MMcf per day (2015 – 19 MMcf per day). Operating Margin was $4 million in 2016 (2015 – $10 million), declining primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	**2016**	2015	2014
Foster Creek	**263**	403	796
Christina Lake	**282**	647	794
	545	1,050	1,590
Narrows Lake	**7**	47	175
Telephone Lake	**16**	24	112
Grand Rapids	**6**	38	63
Other [1]	**30**	26	46
Capital Investment [2]	**604**	1,185	1,986

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

Existing Projects

Capital investment at Foster Creek and Christina Lake in 2016 focused on sustaining capital related to existing production and the completion of the Foster Creek phase G and Christina Lake phase F facilities, with ramp-up underway. In addition, we drilled stratigraphic test wells in the first and fourth quarters to help identify well pad locations for sustaining wells and near-term expansion phases. Incremental production from Foster Creek phase G began in the third quarter of 2016 and ramp-up is now expected to take approximately 12 months from start-up. Completion of Foster Creek phase G added gross production capacity of 30,000 barrels per day. Incremental production from Christina Lake phase F began in the fourth quarter of 2016 and ramp-up is expected to take approximately 12 months from start-up. Start-up of Christina Lake phase F added gross production capacity of 50,000 barrels per day and approximately 100 gross megawatts of electrical generation capacity.

Capital investment declined in 2016 due to spending reductions in response to the low commodity price environment and multiple capital reduction strategies such as quicker drilling time, supply chain initiatives, redesigned well pads, and longer reach horizontal well pairs. Lower capital investment at Christina Lake is also attributable to the completion of the optimization project in 2015.

In 2016, capital investment at Narrows Lake focused on engineering work. Capital investment declined compared with 2015 due to the suspension of construction.

Emerging Projects

In 2016, capital investment at Telephone Lake focused on front-end engineering work for the central processing facility. Capital investment declined as a result of slowing the pace of development in 2016 in response to the low commodity price environment.

Capital investment at Grand Rapids decreased in 2016 as spending was limited to the wind down of the SAGD pilot. In 2015, a third pilot well pair was completed at Grand Rapids.

Drilling Activity

	Gross Stratigraphic Test Wells			**Gross Production Wells [1]**		
	2016	2015	2014	**2016**	2015	2014
Foster Creek	**95**	124	165	**18**	28	63
Christina Lake	**104**	40	57	**35**	67	67
	199	164	222	**53**	95	130
Narrows Lake	**1**	-	22	**-**	-	-
Telephone Lake	**-**	-	45	**-**	-	-
Grand Rapids	**-**	-	10	**-**	1	-
Other	**5**	-	21	**1**	-	-
	205	164	320	**54**	96	130

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

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

Future Capital Investment

While we expect continued crude oil price volatility in 2017, the progress we have made in 2016 in achieving sustainable cost reductions leaves us well positioned to consider advancing certain strategic growth projects. 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.

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. Construction of phase G, which has an initial design capacity of 50,000 gross barrels per day, is expected to begin 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 phase A engineering and equipment preservation related to the suspension of construction at Narrows Lake and a stratigraphic test well program at Telephone Lake. Further activity with respect to the SAGD pilot at Grand Rapids was deferred in 2016 in response to the low commodity price environment.

DD&A and Exploration Expense

DD&A

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

In 2016, Oil Sands DD&A decreased $42 million due to lower DD&A rates, partially offset by higher sales volumes. The average depletion rate was approximately $11.30 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake. In 2016, an impairment loss of $16 million was recorded related to preliminary engineering costs associated with a cancelled project, and equipment that was written down to its recoverable amount.

DD&A in 2015 compared to 2014 increased $72 million primarily due to higher sales volumes and an impairment loss of $16 million related to a sulphur recovery facility.

Exploration Expense

In 2016, exploration expense was $2 million. In 2015, we expensed $67 million related to exploration assets within the Northern Alberta cash-generating unit ("CGU") that were deemed not to be technically feasible and commercially viable. In 2014, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense.

CONVENTIONAL

Our Conventional operations include 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 in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

Significant developments that impacted our Conventional segment in 2016 compared with 2015 include:

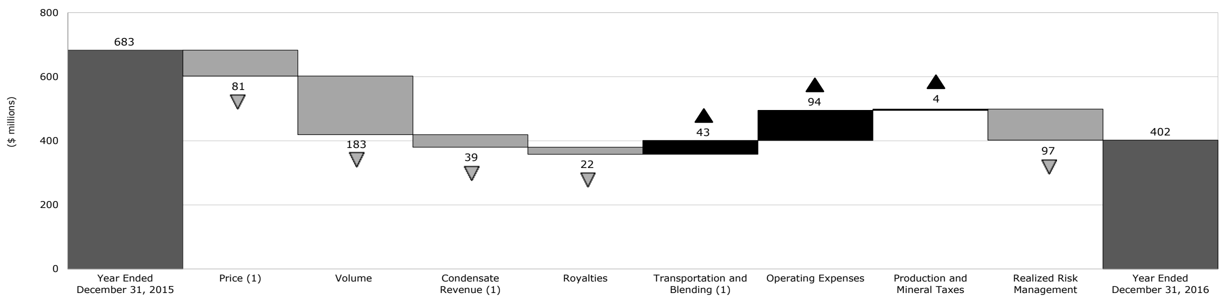
- Reducing our crude oil operating costs by $94 million or $1.60 per barrel;
- Crude oil and natural gas Netbacks, excluding realized risk management activities, of $16.17 per barrel (2015 – $20.92 per barrel) and $1.00 per Mcf (2015 – $1.58 per Mcf), respectively;
- Generating Operating Margin net of capital investment of $373 million, a decrease of 50 percent;
- Crude oil production averaging 56,165 barrels per day, decreasing 16 percent, due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015; and
- Achieving a significant safety milestone with 25 years of employee lost-time-incident-free work at one of our operations.

Conventional – Crude Oil

Financial Results

($ millions)	**2016**	2015	2014
Gross Sales	**936**	1,239	2,456
Less: Royalties	**125**	103	217
Revenues	**811**	1,136	2,239
Expenses			
Transportation and Blending	**170**	213	326
Operating	**287**	381	505
Production and Mineral Taxes	**12**	16	37
(Gain) Loss on Risk Management	**(60)**	(157)	4
Operating Margin	**402**	683	1,367
Capital Investment	**161**	231	812
Operating Margin Net of Related Capital Investment	**241**	452	555

Operating Margin Variance



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

Revenues

Pricing

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

Our crude oil sales price averaged $40.67 per barrel in 2016, a nine percent decrease from 2015, due to lower crude oil benchmark prices, adjusted for applicable differentials, partially offset by a decline in the cost of condensate used for blending our heavy oil. 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 cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our heavy oil sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

(barrels per day)	**2016**	**Percent Change**	2015	Percent Change	2014
Heavy Oil	**29,185**	**(16)%**	34,888	(12)%	39,546
Light and Medium Oil	**25,915**	**(15)%**	30,486	(12)%	34,531
NGLs	**1,065**	**(15)%**	1,253	3%	1,221
	56,165	**(16)%**	66,627	(12)%	75,298

Production decreased as a result of expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015. Divested assets contributed 2,555 barrels per day in 2015. Production also decreased due to reduced capital investment.

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 include the value of condensate. Consistent with the widening of the WCS-Condensate differential in 2016, the proportion of the cost of recovered condensate decreased.

Royalties

Royalties increased $22 million in 2016 primarily due to additional royalty burdens from the sale of our royalty interest and mineral fee title lands business in 2015. In addition, royalties increased due to lower allowable operating and capital costs at Pelican Lake and Weyburn, partially offset by a reduction in sales volumes and lower sales prices. In 2016, the effective crude oil royalty rate for our Conventional properties was 16.3 percent (2015 – 9.9 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 2016 and 2015.

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

Expenses

Transportation and Blending

Transportation and blending costs decreased $43 million in 2016. Blending costs declined due to a reduction in condensate volumes, consistent with lower production, and a decrease in condensate prices. In 2015, we recorded a $7 million write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. There was no inventory write-down in 2016.

Transportation charges were lower largely due to a decline in sales volumes, partially offset by higher transportation costs associated with optimizing our sales and additional costs due to pipeline capacity commitments in excess of our current production.

Operating

Primary drivers of our operating expenses for 2016 were workforce costs, workover activities, electricity, property taxes and lease costs, repairs and maintenance, and chemical costs. Operating expenses declined $94 million or $1.60 per barrel.

The per-unit decline was primarily due to:

- A decrease in repairs and maintenance and workover costs due to a focus on critical activities;
- Lower chemical costs associated with reduced polymer consumption and chemical optimization;
- Workforce reductions; and
- A decline in electricity costs as a result of lower prices and a decrease in consumption.

These decreases were partially offset by lower production.

Netbacks [1]

	Heavy Oil			Light and Medium		
($/bbl)	**2016**	2015	2014	**2016**	2015	2014
Sales Price [2]	**35.82**	39.95	76.25	**46.48**	50.64	88.30
Royalties	**3.31**	2.97	7.09	**9.28**	5.66	9.15
Transportation and Blending [2]	**4.60**	3.36	3.29	**2.73**	2.91	3.34
Operating Expenses	**13.38**	15.92	20.51	**15.65**	16.27	16.98
Production and Mineral Taxes	**0.01**	0.04	0.18	**1.24**	1.41	2.70
Netback Excluding Realized Risk Management [3]	**14.52**	17.66	45.18	**17.58**	24.39	56.13
Realized Risk Management Gain (Loss)	**3.18**	6.77	(0.03)	**3.11**	6.79	(0.08)
Netback Including Realized Risk Management	**17.70**	24.43	45.15	**20.69**	31.18	56.05

(1) Non-GAAP measure defined in this MD&A. Refer to the Operating Results section of this MD&A for details.
(2) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate, which is blended with the heavy oil.
(3) Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.

Risk Management

Risk management activities for 2016 resulted in realized gains of $60 million (2015 – $157 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	2016	2015	2014
Gross Sales	**321**	450	744
Less: Royalties	**14**	11	12
Revenues	**307**	439	732
Expenses			
Transportation and Blending	**16**	17	20
Operating	**152**	175	198
Production and Mineral Taxes	**-**	2	9
(Gain) Loss on Risk Management	**2**	(52)	(5)
Operating Margin	**137**	297	510
Capital Investment	**10**	13	28
Operating Margin Net of Related Capital Investment	**127**	284	482

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

Revenues

Pricing

In 2016, our average natural gas sales price decreased 20 percent to $2.33 per Mcf, consistent with the decline in the AECO benchmark price.

Production

Production decreased 11 percent to 377 MMcf per day in 2016 due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015, which produced 10 MMcf per day in 2015.

Royalties

Royalties increased compared with 2015. Reduced royalties due to lower prices and production declines were offset by additional royalty burdens from the sale of our royalty interest and mineral fee title lands business in 2015. The average royalty rate in 2016 was 4.7 percent (2015 – 2.7 percent).

Expenses

Transportation

In 2016, transportation costs decreased slightly primarily due to lower sales volumes, partially offset by additional charges from a true-up of 2015 transportation contracts.

Operating

Primary drivers of our operating expenses were property taxes and lease costs, workforce, and repairs and maintenance. In 2016, operating expenses decreased by $23 million primarily due to lower workforce costs, repairs and maintenance, and a decline in electricity costs from lower pricing.

Risk Management

Risk management activities resulted in realized losses of $2 million in 2016 (2015 – realized gains $52 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Capital Investment

($ millions)	2016	2015	2014
Heavy Oil	**44**	63	338
Light and Medium Oil	**117**	168	474
Natural Gas	**10**	13	28
Capital Investment (1)	**171**	244	840

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

Capital investment in 2016 was primarily related to drilling stratigraphic test wells for tight oil, maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment declined compared with 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

Drilling Activity

(net wells, unless otherwise stated)	**2016**	2015	2014
Crude Oil	**9**	32	126
Recompletions	**69**	724	803
Gross Stratigraphic Test Wells	**58**	13	30
Other (1)	**-**	3	40

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

Drilling activity in 2016 focused on drilling stratigraphic test wells for tight oil, and natural gas recompletions performed to optimize production.

Future Capital Investment

With the expectation of continued crude oil price volatility in 2017, we are taking a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2017 crude oil capital investment forecast is between $275 million and $325 million with spending plans mainly focused on sustaining capital and tight oil 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, Exploration Expense and Goodwill Impairment

DD&A

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

Conventional DD&A decreased $581 million in 2016 primarily due to lower DD&A rates, a decrease in asset impairments, and a decline in sales volumes.

The average depletion rate decreased approximately 30 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined primarily due to impairment losses and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

Earlier in 2016, we recorded a $380 million impairment loss for our Northern Alberta CGU (2015 – $184 million) primarily due to a decline in long-term forward heavy crude oil prices. In the fourth quarter of 2016, we reversed $400 million of impairment losses, net of the DD&A that would have been recorded had no impairments occurred. The reversal arose due to the increase in the CGU’s estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. This resulted in a net impairment reversal in 2016 of $20 million.

We also recorded a $65 million (2015 – $ nil) impairment loss earlier in 2016 related to our Suffield CGU. Due to an increase in the estimated recoverable amount of the CGU caused by a decline in expected future royalties, the full impairment loss, net of DD&A ($62 million) was reversed.

In 2016, we recognized impairment losses of $20 million related primarily to equipment that was written down to its recoverable amount.

DD&A in 2015 compared to 2014 increased $66 million primarily due to impairment losses of $184 million in 2015 compared with $65 million in 2014, and higher DD&A rates, partially offset by lower sales volumes. The 2014 impairment loss related to equipment that we did not have future plans for and the shut-in and abandonment of a natural gas property.

Exploration Expense

There was no exploration expense recorded in 2016. In 2015, we expensed $71 million (2014 – $82 million) related to exploration assets within the Northern Alberta and Saskatchewan CGUs that were deemed not to be technically feasible and commercially viable.

Goodwill Impairment

In 2014, we recorded $497 million of goodwill impairment associated with our Pelican Lake property.

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries (the “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 2016, we loaded an average of 11,584 gross barrels per day (2015 – 6,530 gross barrels per day).

Significant developments that impacted our Refining and Marketing segment in 2016 compared with 2015 includes:

- Successfully completing the debottlenecking project at Wood River in the third quarter of 2016;
- Increasing crude utilization as a result of strong performance at the Refineries; and
- Generating Operating Margin of $346 million, a 10 percent decline from 2015.

Refinery Operations (1)

	2016	2015	2014
Crude Oil Capacity (Mbbls/d)	**460**	460	460
Crude Oil Runs (Mbbls/d)	**444**	419	423
Heavy Crude Oil	**233**	200	199
Light/Medium	**211**	219	224
Refined Products (Mbbls/d)	**471**	444	445
Gasoline	**236**	228	231
Distillate	**146**	137	137
Other	**89**	79	77
Crude Utilization (percent)	**97**	91	92

(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 2016, crude oil runs and refined product output increased. Strong performance at the Refineries was slightly offset by planned and unplanned maintenance in 2016. In 2015, performance was impacted by unplanned outages and planned turnarounds at the Refineries. Higher heavy crude oil volumes were processed in 2016 primarily due to the optimization of the total crude input slate.

Refining and Marketing Financial Results

($ millions)	2016	2015	2014
Revenues	**8,439**	8,805	12,658
Purchased Product	**7,325**	7,709	11,767
Gross Margin	**1,114**	1,096	891
Expenses			
Operating	**742**	754	703
(Gain) Loss on Risk Management	**26**	(43)	(27)
Operating Margin	**346**	385	215
Capital Investment	**220**	248	163
Operating Margin Net of Related Capital Investment	**126**	137	52

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 2016, Refining and Marketing gross margin increased primarily due to:

- Wider heavy and medium crude oil differentials;
- Higher utilization rates;
- A weaker Canadian dollar relative to the U.S. dollar, which had a positive impact of approximately $36 million on the gross margin;
- An increase in third party crude oil and natural gas sales, primarily due to higher sales volumes and a rise in crude oil sales prices, partially offset by lower natural gas sales prices and an increase in purchased volumes; and
- An inventory write-down of $4 million (2015 – $15 million) related to refined product inventory.

The increase in gross margin was partially offset by lower average market crack spreads and higher costs associated with Renewable Identification Numbers ("RINs"). The Refineries do not blend renewable fuels into the motor fuel products produced. Consequently, to meet the renewable fuel standards, RINs must be purchased. In 2016, the cost of RINs was $294 million (2015 – $200 million). The increase is consistent with the 49 percent increase in the ethanol RINs benchmark price.

Expenses

Primary drivers of operating expenses in 2016 were labour, maintenance and utilities. Reported operating expenses declined primarily due to fewer maintenance activities associated with unplanned outages and planned turnarounds and a decrease in utility costs, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar.

Refining and Marketing – Capital Investment

($ millions)	**2016**	2015	2014
Wood River Refinery	**147**	162	101
Borger Refinery	**66**	78	61
Marketing	**7**	8	1
	220	248	163

Capital expenditures in 2016 focused on completing the debottlenecking project at Wood River, capital maintenance, projects improving the refinery reliability and safety, and environmental initiatives. The Wood River debottlenecking project was successfully completed in the third quarter of 2016. The amount of heavy crude oil processed continues to be dependent on the optimization of the total input slate.

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 increased by $20 million in 2016 primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the power purchase contract and interest rate swaps. In 2016, our risk management activities resulted in $554 million of unrealized losses (2015 – $195 million of unrealized losses).

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

($ millions)	**2016**	2015	2014
General and Administrative	**326**	335	379
Finance Costs	**492**	482	445
Interest Income	**(52)**	(28)	(33)
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036	411
Research Costs	**36**	27	15
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	(156)
Other (Income) Loss, Net	**34**	2	(4)
	644	(538)	1,057

Expenses

General and Administrative

Primary drivers of our general and administrative expense in 2016 were workforce, office rent and information technology costs. General and administrative expenses decreased by $9 million primarily due to a decline in workforce costs related to larger workforce reductions in 2015, lower information technology costs, and reduced discretionary spending. In 2016, severance payments were $19 million (2015 – $43 million). The decrease in general and administrative expenses was partially offset by a $61 million non-cash expense recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and an increase in long-term employee incentive costs primarily due to an increase in our share price.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated partnership contribution payable (that was repaid in March 2014), as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $10 million in 2016 compared with 2015 primarily due to the weakening of the Canadian dollar relative to the U.S. dollar.

The weighted average interest rate on outstanding debt for 2016 was 5.3 percent (2015 – 5.3 percent).

Foreign Exchange

($ millions)	2016	2015	2014
Unrealized Foreign Exchange (Gain) Loss	**(189)**	1,097	411
Realized Foreign Exchange (Gain) Loss	**(9)**	(61)	-
	(198)	1,036	411

The majority of unrealized foreign exchange gains in 2016 stem from translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was three percent stronger at December 31, 2016 compared with December 31, 2015, resulting in unrealized gains.

Other Income (Loss), Net

In November 2016, the Government of Canada rendered its decision to reject the Northern Gateway Pipeline project. As a result, we wrote-off $23 million of costs associated with the project and recorded $7 million of expected costs associated with termination.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2016 was $65 million (2015 – $78 million).

Income Tax

($ millions)	2016	2015	2014
Current Tax			
Canada	**(174)**	586	94
United States	**1**	(12)	(2)
Total Current Tax Expense (Recovery)	**(173)**	574	92
Deferred Tax Expense (Recovery)	**(209)**	(655)	359
	(382)	(81)	451

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

($ millions)	2016	2015	2014
Earnings (Loss) Before Income Tax	**(927)**	537	1,195
Canadian Statutory Rate	**27.0%**	26.1%	25.2%
Expected Income Tax (Recovery)	**(250)**	140	301
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(46)**	(41)	(43)
Non-Deductible Stock-Based Compensation	**5**	7	13
Non-Taxable Capital (Gains) Losses	**(26)**	137	74
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(26)**	135	50
Adjustments Arising From Prior Year Tax Filings	**(46)**	(55)	(16)
Derecognition (Recognition) of Capital Losses	**-**	(149)	(9)
(Recognition) of U.S. Tax Basis	**-**	(415)	-
Change in Statutory Rate	**-**	161	-
Foreign Exchange Gain (Loss) not Included in Net Earnings (Loss)	**-**	-	(13)
Goodwill Impairment	**-**	-	125
Other	**7**	(1)	(31)
Total Tax (Recovery)	**(382)**	(81)	451
Effective Tax Rate	**41.2%**	(15.1)%	37.7%

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.

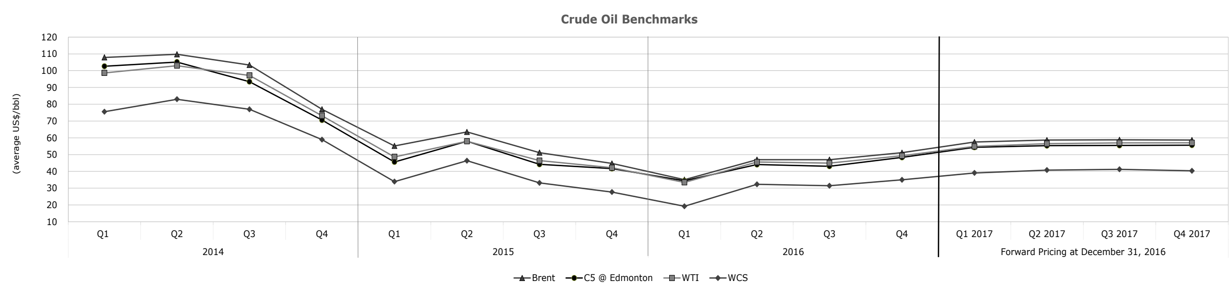
In 2016, we incurred losses for income tax purposes in Canada which will be carried back to recover income taxes previously paid or recognized as a deferred tax recovery. A current tax recovery was also recognized due to prior year adjustments. In 2015, current income tax expense included $391 million attributable to the sale of our royalty interest and mineral fee title lands.

In 2016, a deferred tax recovery was recorded. The recovery was largely due to unrealized risk management losses and the recognition of current year operating losses that will be claimed in a future period. In 2015, we recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of our refining assets. Furthermore, a one-time charge of approximately $161 million was recorded in 2015 from the revaluation of our deferred tax liability due to the increase in the Alberta corporate tax rate offset by operating losses deferred for tax purposes.

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.

QUARTERLY RESULTS

Our quarterly results over the last eight quarters were impacted primarily by volatility in commodity prices. A substantial downward shift in the commodity price environment occurred late in 2014 and low crude oil prices continued throughout 2015 and 2016. Crude oil prices reached a 13 year low, with WTI averaging US$33.45 per barrel in the first quarter of 2016 and gradually increasing to an average of US$49.29 per barrel in the fourth quarter of 2016. Average WTI and WCS benchmark prices increased 17 percent and 26 percent, respectively in the fourth quarter of 2016 compared with 2015. Our companywide Netback of $21.61 per BOE in December 2016, before realized risk management activities, was the highest it has been since July 2015.



($ millions, except per share amounts or where otherwise indicated)	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4
Production Volumes									
Crude Oil (bbls/d)	**219,551**	**208,072**	**198,080**	**197,551**	199,556	210,422	199,954	218,020	216,177
Natural Gas (MMcf/d)	**379**	**392**	**399**	**408**	424	430	450	462	479
Refinery Operations									
Crude Oil Runs (Mbbls/d)	**421**	**463**	**458**	**435**	405	394	441	439	420
Refined Products (Mbbls/d)	**448**	**494**	**483**	**460**	430	414	462	469	442
Revenues	**3,642**	**3,240**	**3,007**	**2,245**	2,924	3,273	3,726	3,141	4,238
Operating Margin (1)	**595**	**487**	**541**	**144**	357	602	932	548	537
Cash From Operating Activities	**164**	**310**	**205**	**182**	322	542	335	275	868
Adjusted Funds Flow (2)	**535**	**422**	**440**	**26**	275	444	477	495	401
Operating Earnings (Loss) (2)	**321**	**(236)**	**(39)**	**(423)**	(438)	(28)	151	(88)	(590)
Per Share – Diluted ($)	**0.39**	**(0.28)**	**(0.05)**	**(0.51)**	(0.53)	(0.03)	0.18	(0.11)	(0.78)
Net Earnings (Loss)	**91**	**(251)**	**(267)**	**(118)**	(641)	1,801	126	(668)	(472)
Per Share – Basic and Diluted ($)	**0.11**	**(0.30)**	**(0.32)**	**(0.14)**	(0.77)	2.16	0.15	(0.86)	(0.62)
Capital Investment (3)	**259**	**208**	**236**	**323**	428	400	357	529	786
Dividends									
Cash Dividends	**42**	**41**	**42**	**41**	132	133	125	138	201
In Shares From Treasury	**-**	**-**	**-**	**-**	-	-	98	84	-
Per Share ($)	**0.05**	**0.05**	**0.05**	**0.05**	0.16	0.16	0.2662	0.2662	0.2662

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

Fourth Quarter 2016 Results Compared With the Fourth Quarter 2015

Production Volumes

Total crude oil production increased 10 percent primarily due to incremental production volumes from Foster Creek phase G and Christina Lake phase F, which started-up in the third quarter and fourth quarter of 2016, respectively, partially offset by expected natural declines from our conventional production. Natural gas production in the fourth quarter of 2016 decreased 11 percent due to expected natural declines. We continued to focus capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Refinery Operations

Crude oil runs and refined product output increased in 2016, despite unplanned outages at the Borger refinery. In 2015, the Wood River refinery experienced planned and unplanned outages in the fourth quarter.

Revenue

Revenues increased $718 million primarily due to:

- Higher revenues from third-party crude oil and natural gas sales undertaken by the marketing group. The increase was largely due to higher purchased crude oil volumes and a rise in crude oil sales prices;
- A 43 percent rise in crude oil sales prices (excluding financial hedging) to $39.38 per barrel;
- An increase in refining revenues largely due to a rise in refined product output and higher refined product prices; and
- An eight percent increase in crude oil sales volumes.

The increases to revenues were partially offset by higher crude oil royalties.

Operating Margin

Operating Margin increased 67 percent in the three months ended December 31, 2016 compared with 2015. Upstream Operating Margin rose 23 percent due to higher crude oil and natural gas sales prices, and an increase in crude oil sales volumes, partially offset by realized risk management gains of $15 million compared with gains of $223 million in 2015.

Refining and Marketing Operating Margin increased by $148 million. The increase was due to a rise in refined product output, higher utilization rates, a decline in feedstock costs and lower operating costs, partially offset by a decline in average market crack spreads and realized risk management losses compared to gains in 2015.

Cash From Operating Activities and Adjusted Funds Flow

Cash From Operating Activities and Adjusted Funds Flow increased in the fourth quarter of 2016 compared with 2015, primarily due to a higher Operating Margin, as discussed above, and higher severance costs in 2015, partially offset by a lower current income tax recovery in 2016. In 2016, the change in working capital was primarily due to a rise in commodity prices increasing the value of accounts receivables, accounts payable and inventory. In 2015, commodity prices experienced a significant decline, which decreased inventory values.

Operating Earnings (Loss)

In the fourth quarter of 2016, Operating Earnings was $321 million compared with a loss of $438 million in 2015. The improvement was primarily due to a decline in DD&A, related to the reversal of $462 million of impairment losses and lower DD&A rates, an increase in Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and a decline in exploration expense. This was partially offset by an asset impairment of $23 million and termination costs of $7 million as a result of the Government of Canada's decision to reject the Northern Gateway Pipeline project.

The impairment reversal arose primarily due to the increase in our Northern Alberta CGU's estimated recoverable amount caused by an average reduction in expected future operating costs and lower future development costs, partially offset by a decline in estimated reserves. In 2015, we recorded $200 million of impairment losses primarily related to our Northern Alberta CGU due to a decline in long-term forward heavy crude oil prices. There was no exploration expense recorded in 2016. In 2015, we expensed $117 million related to exploration assets that were deemed not to be technically feasible and commercially viable.

Net Earnings (Loss)

In 2016, Net Earnings of $91 million included unrealized risk management losses of $114 million and non-operating foreign exchange losses of $147 million. In 2015, we had a Net Loss of $641 million which included unrealized risk management losses of $26 million and non-operating foreign exchange losses of $212 million.

Capital Investment

Capital investment in the fourth quarter of 2016 was $259 million, a 39 percent decrease from 2015 primarily due to lower spending in our Oil Sands and Conventional segments. Capital investment was reduced with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment.

OIL AND GAS RESERVES AND RESOURCES

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

Developments in 2016 compared with 2015 include:

- Bitumen proved reserves increasing seven percent primarily due to Christina Lake adding 186 million barrels of proved reserves resulting from regulatory approval of the Kirby East area expansion converting probable reserves to proved reserves, and from improved reservoir performance;
- Proved plus probable bitumen reserves increasing one percent as improved reservoir performance at Foster Creek and Christina Lake offset 2016 production;
- Both heavy oil proved reserves and heavy oil proved plus probable reserves declining 14 percent primarily due to the deferral of drilling at Pelican Lake;
- Light and medium oil and NGLs proved reserves and light and medium oil and NGLs proved plus probable reserves decreasing eight percent and six percent, respectively, as production exceeded additions;
- Natural gas proved reserves declining 10 percent and natural gas proved plus probable reserves decreasing nine percent as additions and improved performance was more than offset by reductions due to production; and
- Bitumen best estimate economic contingent resources decreasing five percent to 8.8 billion barrels and bitumen best estimate prospective resources decreasing three percent to 7.1 billion barrels, both primarily due to a slightly lower recovery factor for select properties with increased well pair spacing.

The reserves and resources data that follows is presented as at December 31, 2016 using McDaniel & Associates Consultants Ltd.'s ("McDaniel's") January 1, 2017 forecast prices and inflation. Comparative information as at December 31, 2015 uses McDaniel's January 1, 2016 forecast prices and inflation.

Reserves

As at December 31,	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
(before royalties)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Proved	**2,343**	2,183	**114**	133	**101**	110	**652**	721
Probable	**976**	1,115	**75**	87	**44**	44	**212**	232
Proved plus Probable	**3,319**	3,298	**189**	220	**145**	154	**864**	953

Reconciliation of Proved Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2015	**2,183**	**133**	**110**	**721**
Extensions and Improved Recovery	**154**	**-**	**-**	**-**
Technical Revisions	**61**	**(8)**	**1**	**79**
Dispositions	**-**	**-**	**-**	**(1)**
Production [(1)]	**(55)**	**(11)**	**(10)**	**(147)**
December 31, 2016	**2,343**	**114**	**101**	**652**
Year Over Year Change	**160**	**(19)**	**(9)**	**(69)**
	7%	**(14)%**	**(8)%**	**(10)%**

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

Reconciliation of Probable Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2015	**1,115**	**87**	**44**	**232**
Technical Revisions	**(139)**	**(12)**	**-**	**(20)**
December 31, 2016	**976**	**75**	**44**	**212**
Year Over Year Change	**(139)**	**(12)**	**-**	**(20)**
	(12)%	**(14)%**	**-%**	**(9)%**

Contingent and Prospective Resources

As at December 31, (billions of barrels, before royalties)	Bitumen 2016	2015
Economic Contingent Resources [1]		
Best Estimate	**8.8**	9.3
Prospective Resources [1] [2]		
Best Estimate	**7.1**	7.4

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

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), and material risks and uncertainties associated with estimates of reserves is contained in our AIF for the year ended December 31, 2016. Further information with respect to contingent and prospective resources including material risks and uncertainties, project descriptions, significant factors relevant to the resource estimates, and contingencies which prevent the classification of contingent resources as reserves is contained in our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2016. Both our AIF and the Statement of Contingent and Prospective Resources are available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2016	2015	2014
Cash From (Used In)			
Operating Activities	**861**	1,474	3,526
Investing Activities	**(1,079)**	888	(4,350)
Net Cash Provided (Used) Before Financing Activities	**(218)**	2,362	(824)
Financing Activities	**(168)**	894	(797)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**1**	(34)	52
Increase (Decrease) in Cash and Cash Equivalents	**(385)**	3,222	(1,569)

As at December 31,	2016	2015	2014
Cash and Cash Equivalents	**3,720**	4,105	883
Committed and Undrawn Credit Facility	**4,000**	4,000	3,000

Cash From (Used In) Operating Activities

Cash From Operating Activities decreased in 2016 mainly due to lower Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,423 million at December 31, 2016 compared with $4,337 million at December 31, 2015. The change in working capital was due to the improvement of commodity prices at the end of 2016 compared with 2015, resulting in higher accounts receivable, accounts payable, and Refining and Marketing inventory values. In addition, crude oil inventory volumes rose year over year.

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

Cash From (Used In) Investing Activities

In 2016, cash used in investing activities was primarily for capital investment. In 2015, the divestiture of our royalty interest and mineral fee title lands business for approximately $2.9 billion, net of tax, resulted in net cash generated by investing activities.

Cash From (Used In) Financing Activities

In 2016, financing activities included dividend payments of $0.20 per share or $166 million (2015 – $0.8524 per share or $710 million, of which $528 million was paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. In 2015, cash from financing activities included net proceeds of $1.4 billion from the issuance of common shares which was partially offset by a net repayment of short-term borrowings.

Our long-term debt at December 31, 2016 was $6,332 million (2015 – $6,525 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $193 million decrease in long-term debt is due to the change in the Canadian dollar relative to the U.S. dollar.

As at December 31, 2016, 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 December 31, 2016:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,720**	**N/A**
Committed Credit Facility	**1,000**	**April 2019**
Committed Credit Facility	**3,000**	**November 2019**
Base Shelf Prospectus (1)	**US$5,000**	**March 2018**

(1) Availability is subject to market conditions.

Committed Credit Facility

As at December 31, 2016, no amounts had been drawn on our committed credit facility.

Under the 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

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

As at December 31, 2016, no issuances had been made under the prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill 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 metrics are used to steward our overall debt position and as measures of our overall financial strength.

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

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

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

As at December 31,	2016	2015	2014
Debt	**6,332**	6,525	5,458
Shareholders' Equity	**11,590**	12,391	10,186
Capitalization	**17,922**	18,916	15,644
Debt to Capitalization	**35%**	34%	35%
Net Debt (1)	**2,612**	2,420	4,575
Shareholders' Equity	**11,590**	12,391	10,186
Capitalization	**14,202**	14,811	14,761
Net Debt to Capitalization	**18%**	16%	31%

(1) Net Debt is defined as Debt net of Cash and Cash Equivalents.

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

As at December 31,	**2016**	2015	2014
Debt	**6,332**	6,525	5,458
Net Debt [(1)]	**2,612**	2,420	4,575
Adjusted EBITDA			
Net Earnings (Loss)	**(545)**	618	744
Add (Deduct):			
Finance Costs	**492**	482	445
Interest Income	**(52)**	(28)	(33)
Income Tax (Recovery) Expense	**(382)**	(81)	451
DD&A	**1,498**	2,114	1,946
Goodwill Impairment	**-**	-	497
E&E Impairment	**2**	138	86
Unrealized (Gain) Loss on Risk Management	**554**	195	(596)
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036	411
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	(156)
Other (Income) Loss, Net	**34**	2	(4)
	1,409	2,084	3,791
Debt to Adjusted EBITDA	**4.5x**	3.1x	1.4x
Net Debt to Adjusted EBITDA	**1.9x**	1.2x	1.2x

(1) Net Debt is defined as Debt net of Cash and Cash Equivalents.

Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at December 31, 2016, there were approximately 833 million common shares outstanding (2015 – 833 million common shares). Cenovus issued 76.2 million common shares in 2015, including 8.7 million shares issued under the dividend reinvestment plan and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 27 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at January 31, 2017	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**44,982**	**33,379**
Other Stock-Based Compensation Plans [(1)]	**11,617**	**1,598**

(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. The items below have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise.

($ millions)	Expected Payment Date 2017	2018	2019	2020	2021	Thereafter	**Total**
Operating							
Transportation and Storage [(1)]	682	711	722	1,031	1,239	21,875	**26,260**
Operating Leases (Building Leases)	101	146	146	145	142	2,465	**3,145**
Product Purchases	70	-	-	-	-	-	**70**
Other Long-term Commitments	80	27	26	15	15	108	**271**
Interest on Long-term Debt	339	339	339	239	239	3,828	**5,323**
Decommissioning Liabilities	43	47	47	35	27	6,070	**6,269**
Other	19	10	7	6	4	16	**62**
Total Operating	1,334	1,280	1,287	1,471	1,666	34,362	**41,400**
Investing							
Capital Commitments	23	3	-	-	-	-	**26**
Total Investing	23	3	-	-	-	-	**26**
Financing							
Long-term Debt (principal only)	-	-	1,746	-	-	4,632	**6,378**
Other	-	1	1	1	-	3	**6**
Total Financing	-	1	1,747	1	-	4,635	**6,384**
Total Payments [(2)]	1,357	1,284	3,034	1,472	1,666	38,997	**47,810**
Fixed Price Product Sales	3	-	-	-	-	-	**3**

(1) Includes transportation commitments of $19 billion that are subject to regulatory approval or have been approved but are not yet in service.
(2) Contracts on behalf of FCCL Partnership ("FCCL") and WRB Refining LP ("WRB") are reflected at our 50 percent interest.

As operator of Foster Creek, Christina Lake and Narrows Lake, we are responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

Commitments for various firm service pipeline transportation agreements were $26.3 billion, a decline of $1.1 billion from 2015. Our obligations were reduced primarily due to our use of contracts and changes in toll estimates. This was partially offset by increases to our U.S. dollar commitments due to the weakening of the Canadian dollar relative to the U.S. dollar. These agreements, some of which are subject to regulatory approval or have been approved but are not yet in service, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth.

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our purchase in 2015 of our crude-by-rail terminal and exporting crude oil from the U.S. Gulf Coast. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, assessing options to maximize the value of our crude oil by offering a wider range of products, including existing dilbit blends, partially upgraded bitumen, under-blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

As at December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

As at December 31, 2016, Cenovus remained a party to fixed price physical contracts for natural gas with a current delivery of approximately 21 MMcf per day, with varying terms and volumes through to February 1, 2017. The total volume to be delivered within the terms of these contracts is 11 Bcf of natural gas, at a weighted average price of $4.94 per Mcf.

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

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. 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 Consolidated Financial Statements.

Related Party Transactions

Cenovus did not enter into any related party transactions during the years ended December 31, 2016 or 2015, except for our key management compensation. A summary of key management compensation can be found in the notes to the Consolidated Financial Statements.

RISK MANAGEMENT

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus.

Risk Governance

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

Risk Assessment

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

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

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

Significant Risk Factors

The following discussion describes the financial, operational and regulatory risks relating to Cenovus and our operations. A description of the risk factors and uncertainties can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2016.

Financial Risk

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

Commodity Prices

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

Crude oil and natural gas prices are impacted by a number of factors, including but not limited to, global and regional supply and demand and economic conditions, the actions of OPEC, government regulation, political stability, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility. Changing prices will affect the revenues generated by the sale of our production. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

Commodity prices began to decline in the fourth quarter of 2014 and have remained at low levels throughout 2015 and 2016 with a gradual improvement starting in the second quarter of 2016. Should commodity prices decline or remain at current low levels, our capital spending could be reduced causing projects to be impaired, delayed or cancelled, and production could be curtailed or suspended, among other impacts.

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within the refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 32 to the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(216)**	**560**	**344**	(571)	123	(448)
Natural Gas	**-**	**-**	**-**	(59)	55	(4)
Refining	**(1)**	**5**	**4**	(36)	10	(26)
Power	**6**	**(14)**	**(8)**	10	5	15
Interest Rate	**-**	**3**	**3**	-	2	2
(Gain) Loss on Risk Management	**(211)**	**554**	**343**	(656)	195	(461)
Income Tax Expense (Recovery)	**54**	**(150)**	**(96)**	175	(54)	121
(Gain) Loss on Risk Management, After Tax	**(157)**	**404**	**247**	(481)	141	(340)

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

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices on risk management positions as at December 31, 2016 could have resulted in unrealized gains (losses) for the year as follows:

Commodity	**Sensitivity Range**	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	**(198)**	**193**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**1**	**(1)**
Interest Rate Swaps	± 50 Basis Points	**45**	**(52)**

Risks Associated with Derivative Financial Instruments

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

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

Liquidity

Liquidity risk is the risk that we will not be able to meet all our financial obligations as they come due, be unable to liquidate assets in a timely manner at a reasonable price, or access capital markets at acceptable terms and conditions. In declining economic times, such as a low commodity price environment, or due to unforeseen events that impact financial markets, our liquidity risk could become heightened.

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

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including, but not limited to, cash and cash equivalents, Cash From Operating Activities, an undrawn credit facility and availability under our base shelf prospectus. At December 31, 2016, we had cash and cash equivalents of $3.7 billion. No amounts were drawn on our $4.0 billion committed credit facility. In addition, we had US$5.0 billion in unused capacity under our base shelf prospectus, the availability of which is dependent on market conditions.

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 may enter into forward or other foreign exchange contracts. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Operational Risk

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

Market Access and Transportation Restrictions

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

Operational Outages and Major Environmental or Safety Incidents

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

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

Project Execution

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

Cost Management

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

Reserves Replacement

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

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. There is a risk that Cenovus may have difficulty sourcing, developing and retaining the required talent for current and future operations. Failure to retain critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies could have a material adverse effect on our financial condition, results of operations and pace of growth.

Information Systems

Our operations rely heavily on information technology, such as computer hardware and software systems, to properly operate our business. These systems could be damaged, corrupted or interrupted by natural disasters, telecommunications failures, power loss, malicious acts or code, computer viruses, physical or electronic security breaches, user misuse or user error. A system disruption or breach could adversely impact our reputation, financial condition, results of operations and cash flows.

Regulatory Risk

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

Regulatory Approvals

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

Abandonment and Reclamation Cost Risk

The current oil and gas asset abandonment, reclamation and remediation ("A&R") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one party becomes insolvent and is unable to fund the A&R activities, the solvent parties can claim the insolvent party's share of the costs (orphaned asset) against the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees and approval holders, including Cenovus, based on each party's proportionate share of the oil and gas industry's deemed A&R liabilities for facilities, wells and unreclaimed sites in Alberta. Saskatchewan has a similar regime.

In May, 2016, the Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation ("Redwater") that trustees and receivers of insolvent parties may disclaim or renounce uneconomic oil and gas assets to the Alberta Energy Regulator (the "AER") before starting the sales process for the insolvent party's assets. These wells and facilities then become "orphans" to be remediated by the OWA. Prior to Redwater, the sales process for the insolvent party's assets would have typically included both the economic and uneconomic assets, and only in instances where the sales process failed to sell all of the assets would the remaining assets be classified as orphaned assets by the AER and disclaimed to the OWA. Redwater is currently under appeal by the AER and the OWA.

In June 2016, in response to Redwater, the AER released Bulletin 2016-16 which, among other things, implements important changes to the AER's procedures relating to liability management ratings, licence eligibility and transfers. The governments of British Columbia and Saskatchewan have announced similar policies within those provinces. These changes may impact Cenovus's ability to transfer its licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

Due to the current economic environment and the Redwater decision, the number of orphaned wells in Alberta may increase significantly and accordingly, the aggregate value of the A&R liabilities assumed by the OWA may increase. It is unclear how these liabilities will be satisfied by the OWA and the manner, if any, through which the OWA or provincial regulators may seek compensation for such liabilities from industry participants, including Cenovus. While the impact on Cenovus of any legislative, regulatory or policy decisions as a result of the Redwater decision, and its pending appeal, cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may adversely impact, among other things, our business, financial condition, results of operations and cash flows.

Tax Laws

Income tax laws, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects Cenovus and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or the detriment of its shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and its shareholders.

United States Tax Risk

In November 2016, the U.S. elected a Republican president. As a result, the Republicans control both the U.S. House of Representatives and the U.S. Senate. The new administration is reported to be considering a comprehensive tax reform that could have a significant impact on Cenovus's financial condition or results from operations.

Royalty Regimes

The Governments of Alberta and Saskatchewan receive royalties on the production of crude oil and natural gas from lands where they own the mineral rights. On January 1, 2017, the Government of Alberta implemented a modernized royalty framework (the "Modernized Framework") for conventional production based on recommendations of the Royalty Review Advisory Panel. The Modernized Framework includes new programs, formulas, royalty rates, and new drilling and completion cost reporting requirements. The new framework allows all conventional wells drilled prior to 2017 to be grandfathered under the current rules for 10 years. The oil sands royalty regime was left intact with exception of some proposed modifications to the allowed cost framework and certain administrative components of the regime.

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

Environmental Regulations

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

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

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

Species at Risk Act

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

Climate Change

Various federal, provincial and U.S. state governments have announced intentions to regulate greenhouse gas emissions ("GHG") and other air pollutants. The Alberta Climate Leadership Plan introduced a new GHG emissions pricing regime. The Climate Leadership Act (the "CLA") received royal assent on June 13, 2016 and came into force on January 1, 2017. The Climate Leadership Regulation ("CL Regulation"), which provides further detail in respect of the carbon levy regime set out in the CLA, was released on November 3, 2016, and also came into force on January 1, 2017. The CLA establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel, based on rates of $20 per tonne of GHG emissions as of January 1, 2017 and $30 per tonne for 2018. The carbon levy revenue will be used to fund initiatives to reduce GHG emissions, to support Alberta's ability to adapt to climate change, and for rebates or adjustments related to the carbon levy to consumers, businesses and communities.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of GHG emitting facilities. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners to 20 percent below an average baseline of the facility's historic emissions performance. We may meet the reduction requirements in one of four ways: (1) reducing emissions intensity at our facilities; (2) purchasing or using emission offset credits (3) purchasing or using performance credits; or (4) contributing to an emissions fund at a price of $30 per tonne. Beginning in 2018, facilities subject to the SGER will transition from a historic emissions performance baseline to an output-based allocation approach.

Under the CLA and CL Regulation, facilities subject to the SGER (which includes Cenovus's operating oil sands assets) are exempt from the carbon levy. Activities integral to oil and gas production processes are exempt until 2023. At this time, the determination of what constitutes an activity that is "integral" to conventional oil and gas production is still being clarified with the Alberta government. We expect our operations to have minimal direct carbon levy exposure until 2023.

In addition to GHG emissions pricing, the CLP outlined two additional components relevant to the oil and gas sector: (1) limiting oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (2) reducing methane emissions from oil and gas activities by 45 percent by 2025. Additional changes to provincial climate change legislation may have adverse effects for us which cannot be reliably or accurately estimated at this time.

In October 2016, the Canadian federal government announced a new national carbon pricing regime (the "Carbon Strategy") in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the Carbon Strategy, all provinces will be required to adopt a carbon pricing scheme that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Carbon Strategy also proposes a federal backstop in the event that jurisdictions fail to meet the benchmark. As Alberta has already established a carbon pricing system, in the short-term, the national price on carbon will likely have little additional impact. It is unclear how the Carbon Strategy will be imposed on Saskatchewan.

Adverse impacts to our business as a result of comprehensive GHG legislation and regulations, may include increased compliance costs, permitting delays, and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil and certain refined products. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus. Beyond existing legal requirements, the extent and magnitude of any adverse impacts of these additional programs or regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Water Licences

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

Alberta's Land-Use Framework

The Government of Alberta implemented the Lower Athabasca Regional Plan ("LARP"), which identifies legally binding management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation. This may have a material adverse effect on our financial condition, results of operations and cash flows.

The Government of Alberta has also implemented the South Saskatchewan Regional Plan ("SSRP"). This plan applies to Cenovus's conventional oil and gas operations in southern Alberta. To date, the SSRP is not expected to materially impact Cenovus's existing conventional oil and gas operations, but no assurance can be given that future expansion of these operations will not be affected. Additional regional plans are in the process of being developed and no assurances can be given that such plans, if approved and implemented, will not materially impact our operations or future operations.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

Critical Judgments in Applying Accounting Policies

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

Joint Arrangements

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

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

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

Exploration and Evaluation Assets

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

Identification of CGUs

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

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

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

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For our upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions, and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets. Refer to the reportable segments section of this MD&A for more details on impairments and reversals.

As at December 31, 2016, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs. Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2016 by our IQREs.

Crude Oil and Natural Gas Prices

The forward prices as at December 31, 2016, used to determine future cash flows from crude oil and natural gas reserves were:

	2017	2018	2019	2020	2021	Average Annual Increase Thereafter
WTI (US$/barrel)	55.00	58.70	62.40	69.00	75.80	2.0%
WCS (C$/barrel)	53.70	58.20	61.90	66.50	71.00	2.0%
AECO (C$/Mcf) (1)	3.40	3.15	3.30	3.60	3.90	2.2%

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

Discount and Inflation Rates

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

Decommissioning Costs

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

Income Tax Provisions

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

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

Changes in Accounting Policies

Cenovus adopted the following new amendment:

Liabilities Arising From Financing Activities

Cenovus has early adopted the disclosure requirements in "*Disclosure Initiative (Amendments to IAS 7)*" ("IAS 7") before the mandatory effective date of January 1, 2017. Additional disclosures for changes in liabilities arising from financing activities have been included in Note 21 of the Consolidated Financial Statements. As allowed by IAS 7, comparative information has not been presented.

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 Consolidated Financial Statements for the year ended December 31, 2016. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Leases

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

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15, "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The 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. It is anticipated that the adoption of IFRS 16 will have a material impact on our Consolidated Balance Sheets due to material operating lease commitments as disclosed in Note 34 of the Consolidated Financial Statements. We plan to apply IFRS 16 initially on January 1, 2019; however, the transition approach on adoption has not yet been determined.

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. Early adoption is permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plan to adopt the standard for the year ended December 31, 2018.

Financial Instruments

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

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The IAS 39 measurement categories for financial assets will be replaced by fair value through profit or loss, fair value through other comprehensive income and amortized cost. Based on our preliminary assessment, we do not believe the change in classification will have a material impact on the Consolidated Financial Statements.

IFRS 9 retains most of the IAS 39 requirements for financial liabilities. However, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. Cenovus currently does not designate any financial liabilities as fair value through profit or loss.

A new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. We do not expect the change in the impairment model to have a material impact on the Consolidated Financial Statements.

In addition, IFRS 9 includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Cenovus does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We plan to adopt IFRS 9 for the year ended December 31, 2018.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2016. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2016.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2016. There have been no changes during the year ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

CORPORATE RESPONSIBILITY

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

We published our 2015 CR report in July 2016, detailing our efforts to accelerate improvement in our environmental performance, protect the health and safety of our staff, invest in and engage with the communities where we operate and maintain the highest standards of corporate governance. Our CR report also lists external recognition we received for our commitment to corporate responsibility and our efforts to balance economic, governance, social and environmental performance. Our CR policy and CR report are available on our website at cenovus.com.

OUTLOOK

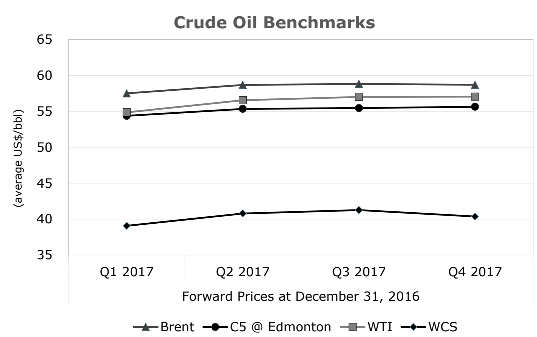
We anticipate ongoing price volatility for the foreseeable future and accordingly, we continue to be prudent in how we allocate capital and manage the pace at which we choose to invest. We will focus on maximizing our cost efficiencies and maintaining financial resilience while delivering safe and reliable operations, as well as resuming investment in certain strategic growth projects. We will continue to monitor future changes implemented by the newly elected U.S. president, some of which could have a significant impact on Cenovus's future financial results.

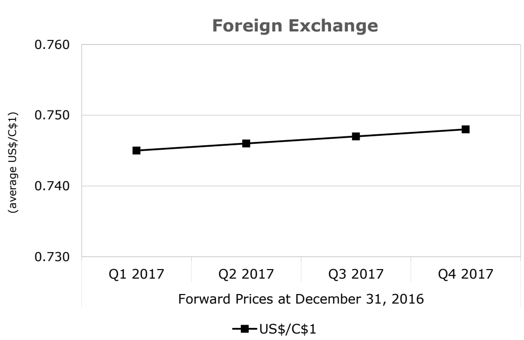
The following outlook commentary is focused on the next twelve months.

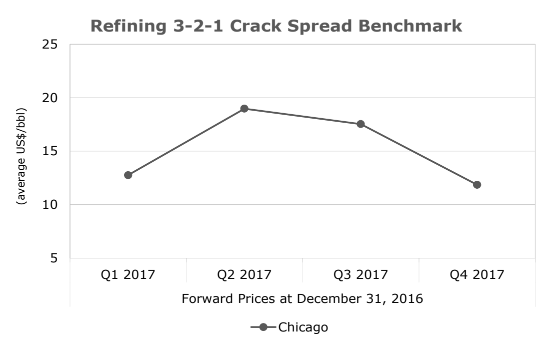
Commodity Prices Underlying our Financial Results

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 and we expect that they will be impacted by the pace of rebalancing excess crude oil and refined product inventories.

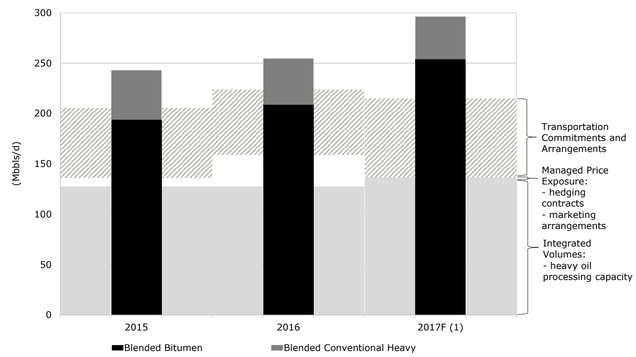
The Canadian dollar will likely continue to be tied to crude oil prices, tempered by rising interest rate expectations in the U.S. Overall, excluding the change in crude oil prices, a stronger Canadian dollar is expected to have a negative impact on our revenues and Operating Margin.

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

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

Protection From Canadian Price Differentials



(1) Expected production volumes. For further information, refer to our 2017 Guidance as updated on December 8, 2016, available at cenovus.com.

Key Priorities for 2017

Disciplined and Value-added Growth

We anticipate capital investment in 2017 to be between $1.2 billion and $1.4 billion. We plan 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.

Maintain Financial Resilience

Maintaining our financial resilience, while maintaining safe operations, continues to be a top priority. At December 31, 2016, we had $3.7 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 15 years, with no debt maturing until the fourth quarter of 2019. We also have a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

Market Access

Access to markets for Canadian crude oil continues 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 and resources data and related information were prepared effective December 31, 2016 by independent qualified reserves evaluators, based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using McDaniel's January 1, 2017 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2016 and our Statement of Contingent and Prospective Resources.

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

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2016 reserves evaluation, which comply with NI 51-101 requirements.

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

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

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

Additional information with respect to the evaluation and reporting of our reserves in accordance with NI 51-101 and material risks and uncertainties associated with estimates of reserves is contained in our AIF for the year ended December 31, 2016. Further information with respect to contingent and prospective resources including material risks and uncertainties, project descriptions, significant factors relevant to the resource estimates, and contingencies which prevent the classification of contingent resources as reserves is contained in our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2016. Both our AIF and the Statement of Contingent and Prospective Resources are available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com.

Forward-looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "committed", "can be", "pursue", "capacity", "could", "should", "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; expected impacts of completion of the Wood River debottlenecking project; 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 and environmental regulations, including the CLA, CL Regulation, SGER and Carbon Strategy; the potential effectiveness of our risk management strategies; new accounting standards and the timing for the adoption thereof by Cenovus; 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; 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 of US$48.75/bbl, WTI of US$47.25/bbl; WCS of US$31.50/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.60/GJ; Chicago 3-2-1 crack spread of US$11.25/bbl; and an exchange rate of $0.74 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated business; reliability of our assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with the fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; changes in our labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental (including in relation to abandonment, reclamation and remediation costs, levies or liability recovery with respect thereto), greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the period ended December 31, 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	CBM	Coal Bed Methane
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	trademark of Cenovus Energy Inc.

NETBACK RECONCILIATIONS

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. 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 non-cash write-downs of product inventory until the inventory is sold. Netbacks reflect our margin on a per-barrel basis of unblended crude oil. As such, 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 COGE Handbook.

The following tables provide a reconcilition of the items comprising Netbacks (in millions of dollars) to our Consolidated Financial Statements.

Sales Volumes

(barrels per day, unless otherwise stated)	**2016**	2015	2014
Oil Sands			
Foster Creek	**69,647**	64,467	57,336
Christina Lake	**79,481**	73,872	67,349
	149,128	138,339	124,685
Conventional			
Heavy Oil	**28,958**	35,597	39,231
Light and Medium Oil	**25,965**	30,517	34,434
Natural Gas Liquids ("NGLs")	**1,065**	1,253	1,221
	55,988	67,367	74,886
Crude Oil and NGLs Sales	**205,116**	205,706	199,571
Natural Gas Sales (MMcf per day)	**394**	441	488
Total Sales (BOE per day)	**270,783**	279,206	280,904

Total Crude Oil, NGLs and Natural Gas

	Basis of Netback Calculation			Adjustments			Per Consolidated Financial Statements [1]	
Year ended December 31, 2016 ($ millions)	Crude Oil & NGLs	Natural Gas	Total	Condensate	Inventory [2]	Other	Other Products	Total Upstream
Revenues								
Gross Sales	2,342	335	2,677	1,505	-	2	12	**4,196**
Less: Royalties	134	14	148	-	-	-	-	**148**
	2,208	321	2,529	1,505	-	2	12	**4,048**
Expenses								
Transportation and Blending	436	17	453	1,505	(51)	-	-	**1,907**
Operating	777	165	942	-	-	(6)	9	**945**
Production and Mineral Taxes	12	-	12	-	-	-	-	**12**
Netback	983	139	1,122	-	51	8	3	**1,184**
(Gain) Loss on Risk Management	(243)	-	(243)	-	-	6	-	**(237)**
Operating Margin	1,226	139	1,365	-	51	2	3	**1,421**

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

Year ended December 31, 2015 ($ millions)	Basis of Netback Calculation Crude Oil & NGLs	Natural Gas	Total	Adjustments Condensate	Inventory [2]	Other	Per Consolidated Financial Statements [1] Other Products	Total Upstream
Revenues								
Gross Sales	2,656	469	3,125	1,583	-	3	28	**4,739**
Less: Royalties	132	11	143	-	-	-	-	**143**
	2,524	458	2,982	1,583	-	3	28	**4,596**
Expenses								
Transportation and Blending	411	18	429	1,583	33	-	-	**2,045**
Operating	899	193	1,092	-	-	(10)	10	**1,092**
Production and Mineral Taxes	16	2	18	-	-	-	-	**18**
Netback	1,198	245	1,443	-	(33)	13	18	**1,441**
(Gain) Loss on Risk Management	(564)	(59)	(623)	-	-	10	-	**(613)**
Operating Margin	1,762	304	2,066	-	(33)	3	18	**2,054**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Year ended December 31, 2014 ($ millions)	Basis of Netback Calculation Crude Oil & NGLs	Natural Gas	Total	Adjustments Condensate	Inventory [2]	Other	Per Consolidated Financial Statements [1] Other Products	Total Upstream
Revenues								
Gross Sales	5,198	778	5,976	2,221	-	33	31	**8,261**
Less: Royalties	450	15	465	-	-	-	-	**465**
	4,748	763	5,511	2,221	-	33	31	**7,796**
Expenses								
Transportation and Blending	217	21	238	2,221	18	-	-	**2,477**
Operating	1,123	216	1,339	-	-	(4)	13	**1,348**
Production and Mineral Taxes	37	9	46	-	-	-	-	**46**
Netback	3,371	517	3,888	-	(18)	37	18	**3,925**
(Gain) Loss on Risk Management	(37)	(6)	(43)	-	-	4	-	**(39)**
Operating Margin	3,408	523	3,931	-	(18)	33	18	**3,964**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Oil Sands Crude Oil

Year ended December 31, 2016 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Adjustments Condensate	Inventory [2]	Per Consolidated Financial Statements[1] Total Oil Sands Crude Oil
Revenues						
Gross Sales	773	736	1,509	1,402	-	**2,911**
Less: Royalties	-	9	9	-	-	**9**
	773	727	1,500	1,402	-	**2,902**
Expenses						
Transportation and Blending	225	137	362	1,402	(44)	**1,720**
Operating	269	217	486	-	-	**486**
Netback	279	373	652	-	44	**696**
(Gain) Loss on Risk Management	(90)	(89)	(179)	-	-	**(179)**
Operating Margin	369	462	831	-	44	**875**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Year ended December 31, 2015 ($ millions)	Basis of Netback Calculation			Adjustments		Per Consolidated Financial Statements[1]
	Foster Creek	Christina Lake	Total Crude Oil	Condensate	Inventory [2]	Total Oil Sands Crude Oil
Revenues						
Gross Sales	792	767	1,559	1,441	-	**3,000**
Less: Royalties	11	18	29	-	-	**29**
	781	749	1,530	1,441	-	**2,971**
Expenses						
Transportation and Blending	208	127	335	1,441	38	**1,814**
Operating	295	216	511	-	-	**511**
Netback	278	406	684	-	(38)	**646**
(Gain) Loss on Risk Management	(202)	(198)	(400)	-	-	**(400)**
Operating Margin	480	604	1,084	-	(38)	**1,046**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Year ended December 31, 2014 ($ millions)	Basis of Netback Calculation			Adjustments		Per Consolidated Financial Statements[1]
	Foster Creek	Christina Lake	Total Crude Oil	Condensate	Inventory [2]	Total Oil Sands Crude Oil
Revenues						
Gross Sales	1,453	1,514	2,967	1,996	-	**4,963**
Less: Royalties	125	108	233	-	-	**233**
	1,328	1,406	2,734	1,996	-	**4,730**
Expenses						
Transportation and Blending	41	87	128	1,996	6	**2,130**
Operating	342	273	615	-	-	**615**
Netback	945	1,046	1,991	-	(6)	**1,985**
(Gain) Loss on Risk Management	(29)	(9)	(38)	-	-	**(38)**
Operating Margin	974	1,055	2,029	-	(6)	**2,023**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Conventional Crude Oil and NGLs

Year ended December 31, 2016 ($ millions)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements[1]
	Heavy Oil	Light & Medium	NGLs	Conventional Crude Oil & NGLs	Condensate	Inventory [2]	Other	Total Conventional Crude Oil & NGLs
Revenues								
Gross Sales	380	442	11	833	103	-	-	**936**
Less: Royalties	35	88	2	125	-	-	-	**125**
	345	354	9	708	103	-	-	**811**
Expenses								
Transportation and Blending	49	25	-	74	103	(7)	-	**170**
Operating	142	149	-	291	-	-	(4)	**287**
Production and Mineral Taxes	-	12	-	12	-	-	-	**12**
Netback	154	168	9	331	-	7	4	**342**
(Gain) Loss on Risk Management	(34)	(30)	-	(64)	-	-	4	**(60)**
Operating Margin	188	198	9	395	-	7	-	**402**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Year ended December 31, 2015 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Crude Oil & NGLs	Adjustments: Condensate	Inventory [2]	Other	Per Consolidated Financial Statements[1]: Total Conventional Crude Oil & NGLs
Revenues								
Gross Sales	519	564	14	1,097	142	-	-	**1,239**
Less: Royalties	39	63	1	103	-	-	-	**103**
	480	501	13	994	142	-	-	**1,136**
Expenses								
Transportation and Blending	44	32	-	76	142	(5)	-	**213**
Operating	207	181	-	388	-	-	(7)	**381**
Production and Mineral Taxes	-	16	-	16	-	-	-	**16**
Netback	229	272	13	514	-	5	7	**526**
(Gain) Loss on Risk Management	(88)	(76)	-	(164)	-	-	7	**(157)**
Operating Margin	317	348	13	678	-	5	-	**683**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Year ended December 31, 2014 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Crude Oil & NGLs	Adjustments: Condensate	Inventory [2]	Other	Per Consolidated Financial Statements[1]: Total Conventional Crude Oil & NGLs
Revenues								
Gross Sales	1,092	1,110	29	2,231	225	-	-	**2,456**
Less: Royalties	101	115	1	217	-	-	-	**217**
	991	995	28	2,014	225	-	-	**2,239**
Expenses								
Transportation and Blending	47	42	-	89	225	12	-	**326**
Operating	294	214	-	508	-	-	(3)	**505**
Production and Mineral Taxes	3	34	-	37	-	-	-	**37**
Netback	647	705	28	1,380	-	(12)	3	**1,371**
(Gain) Loss on Risk Management	-	1	-	1	-	-	3	**4**
Operating Margin	647	704	28	1,379	-	(12)	-	**1,367**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.