Second Quarter
2016

cenovus ENERGY

Cenovus has strong second-quarter operational performance
Oil sands production increases, operating costs decline

Calgary, Alberta (July 28, 2016) – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) continued to deliver strong and reliable operating performance in the second quarter of 2016. The company remains on track with its plans to bring on two new oil sands expansion phases and achieve up to $500 million in capital, operating and general and administrative (G&A) cost reductions compared with its original 2016 budget.

"We've achieved significant sustainable improvements in our cost structure over the last year and a half, and we'll remain vigilant on costs to maximize our competitive position in this challenging and volatile commodity price environment," said Brian Ferguson, Cenovus President & Chief Executive Officer. "Our reduced cost base and strong operational performance, coupled with an improvement in benchmark oil and natural gas prices from the lows reached earlier this year, contributed to a solid second quarter."

Key developments

- Decreased per-barrel oil sands operating costs by 24% and per-barrel conventional crude oil operating costs by 9% compared with the second quarter of 2015
- Achieved production at Foster Creek of almost 69,000 barrels per day (bbls/d) net in June. Second-quarter production was nearly 65,000 bbls/d net, 11% higher than in the same period of 2015. Foster Creek is on track to exit the year with volumes above 70,000 bbls/d net
- Increased production at Christina Lake to more than 78,000 bbls/d net, 8% higher than in the second quarter of 2015
- The Foster Creek phase G and Christina Lake phase F expansion projects remain on track to add incremental production in the third quarter
- Exited the quarter with nearly $8 billion in liquidity, including $3.8 billion in cash, $4 billion in unused credit facilities, and net debt to capitalization of 17%

Production & financial summary			
(For the period ended June 30) Production (before royalties)	**2016** **Q2**	**2015** **Q2**	% change
Oil sands (bbls/d)	**142,604**	**130,734**	9
Conventional oil[1] (bbls/d)	**55,476**	**69,220**	-20
Total oil (bbls/d)	**198,080**	**199,954**	-1
Natural gas (MMcf/d)	**399**	**450**	-11
Financial ($ millions, except per share amounts)			
Cash flow[2]	**440**	**477**	-8
Per share diluted	**0.53**	**0.58**	
Operating earnings/loss[2]	**-39**	**151**	
Per share diluted	**-0.05**	**0.18**	
Net earnings/loss	**-267**	**126**	
Per share diluted	**-0.32**	**0.15**	
Capital investment	**236**	**357**	-34

[1] Includes natural gas liquids (NGLs).

[2] Cash flow and operating earnings/loss are non-GAAP measures as defined in the Advisory.

Overview

Cenovus's strong operational performance in the second quarter of 2016 included a 9% increase in combined oil sands production and a 24% decrease in per-barrel oil sands operating costs compared with the same quarter of 2015. The company's year-over-year financial performance was negatively impacted by the significant decline in crude oil and natural gas prices from the previous year's quarter. However, an increase in crude oil and natural gas prices from the multi-year lows reached in the first three months of 2016 contributed to improved cash flow compared with the first quarter of this year.

Oil production

Production at Cenovus's Foster Creek oil sands project averaged approximately 65,000 bbls/d net in the second quarter, 11% higher than in the same period a year earlier when a precautionary shutdown due to nearby forest fire activity reduced volumes by approximately 10,500 bbls/d net. Operations at Foster Creek have not been affected by forest fire activity in 2016. June production averaged just under 69,000 bbls/d net as Cenovus continued to ramp up new sustaining well pads at Foster Creek and brought a number of wells that were down for servicing back online, as planned. At the end of June, the company had commissioned the majority of the facilities for its Foster Creek expansion phase G, which is on track to be completed and add incremental oil volumes in the third quarter, with ramp-up expected over an 18-month period. Cenovus continues to anticipate exiting 2016 with Foster Creek production above 70,000 bbls/d net.

Production at Christina Lake averaged approximately 78,000 bbls/d net in the second quarter, an 8% increase from the same period a year earlier. The increase was largely due to the completion of the Christina Lake optimization project in late 2015 and the reliable performance of the operation's facilities. Christina Lake phase F remains on track for first oil in the third quarter and is expected to ramp up over a 12-month period. During the second quarter, Cenovus successfully commissioned its 100 megawatt Christina Lake cogeneration power plant, with full ramp-up expected in the third quarter. The company is spending a small amount of capital to complete detailed engineering on Christina Lake phase G and is in the process of rebidding work on the project. Cenovus expects to provide more information at the time of its 2017 budget announcement in December about the potential to restart phase G, which was put on hold in late 2014 due to the decline in oil prices.

"Given the strength of our balance sheet and financial position as well as our high level of confidence that the cost reductions we've achieved will be largely sustainable, I'm optimistic about the potential to resume construction on some of our deferred projects," said Ferguson. "However, we still need additional clarity on federal fiscal and regulatory policies that could impact our operating environment."

In the second quarter, Cenovus undertook precautionary staff evacuations at its Christina Lake and Pelican Lake operations due to nearby forest fire activity. While non-essential personnel at Christina Lake were sent home for several days in May due to heightened forest fire risk, essential staff remained at site and safely continued full production. In June, a forest fire near Pelican Lake prompted the orderly shutdown and precautionary evacuation of all personnel from site for two days. Operations and staffing were restored to normal levels in a safe and timely manner.

"I'm extremely pleased with the composure and professionalism our teams have displayed in carrying out these precautionary measures to protect our people and operations this wildfire season," said Kieron McFadyen, Cenovus Executive Vice-President & President, Upstream Oil & Gas. "Fortunately, everyone has remained safe, and our infrastructure has not been impacted by forest fires. Our thoughts go out to everyone who was affected by the fire that devastated Fort McMurray this spring."

Cost reductions

Cenovus remains on track with its target to reduce capital, operating and G&A costs by up to $500 million this year compared with its original 2016 budget. The company expects about two-thirds of its realized cost reductions achieved since the end of 2014 will be sustainable even in a higher commodity price environment.

"I want to acknowledge the hard work of everyone at Cenovus in finding ways to reduce costs over the last year and a half," said Ferguson. "This has made us stronger and more financially resilient, and we'll continue to look for further efficiencies in the months ahead."

Per-barrel operating costs continued to decline in the second quarter, compared with the same period in 2015, including a 24% reduction in combined oil sands operating costs to $8.06 per barrel (bbl). Oil sands non-fuel operating costs fell by 19% to $6.54/bbl primarily as a result of higher production volumes, better prioritization of repairs and maintenance and improved well pump performance. During the second quarter, Christina Lake recorded a larger credit under Alberta's greenhouse gas emissions regulations than in the second quarter of last year, which also helped to reduce operating costs.

As previously announced, Cenovus completed its planned workforce reduction program in the second quarter, bringing total staff reductions since the end of 2014 to 31%. In the second quarter, Cenovus recorded severance costs of approximately $19 million related to its 2016 workforce reductions.

Financial performance

The year-over-year decline in West Texas Intermediate (WTI), Western Canadian Select (WCS) and AECO natural gas prices of 21%, 30% and 53%, respectively, as well as a decline in average market crack spreads contributed to a decrease in second-quarter operating cash flow to $541 million, 42% lower than in the same period of 2015. Upstream operating cash flow was down 45% to $348 million.

The company's refining and marketing business had strong operating performance in the second quarter, with operating cash flow of $193 million. This represents a $216 million improvement from the first quarter of the year, primarily driven by a recovery in market crack spreads and better utilization rates. Year over year, operating cash flow from refining and marketing was down 36% in the second quarter of 2016, primarily due to lower average market crack spreads driven by higher storage levels for refined product and a 75% narrowing of the Brent-WTI price differential.

Cenovus ended the second quarter of 2016 with cash and cash equivalents of approximately $3.8 billion. Including $4.0 billion in undrawn capacity under its committed credit facility, the company has nearly $8 billion in liquidity available, with no debt maturing until the fourth quarter of 2019. At the end of the second quarter, the company's net debt to capitalization was 17% compared with 28% at the end of the second quarter of 2015. Its net debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) was 1.9 times on a trailing 12-month basis, compared with 1.5 times at the end of the same period a year ago.

Cenovus has an active hedging program and will evaluate additional hedging opportunities for 2017 and 2018 to help maintain its financial resilience.

Guidance update

Cenovus has updated its 2016 full-year guidance to reflect actual results for the first six months of the year and the company's estimates for the second half of 2016. The revisions primarily reflect expectations for continued improvement in company-wide operating costs and lower anticipated capital spending at Cenovus's oil sands business. Updated guidance is available at cenovus.com under "Investors."

Second quarter details

Oil sands

Foster Creek

- Production averaged 64,544 bbls/d net in the second quarter of 2016, an 11% increase from the same period of 2015.
- Operating costs at Foster Creek declined 24% to $10.15/bbl in the quarter. Non-fuel operating costs were $8.51/bbl, a 19% drop from a year earlier.
- The steam to oil ratio (SOR), the amount of steam needed to produce one barrel of oil, was 2.9 for the second quarter compared with 2.3 in the same period of 2015. The SOR is expected to decrease as new well pads come online later this year.
- Netbacks, including realized hedging gains, were $13.46/bbl for the quarter, a 45% decrease from the same quarter of 2015.

Christina Lake

- Production averaged 78,060 bbls/d net in the second quarter of 2016, an 8% increase from the same period a year earlier.
- Operating costs were $6.35/bbl in the quarter, a decline of 23% from a year earlier. Non-fuel operating costs were $4.93/bbl, 18% lower than in the same period in 2015.
- The SOR was 1.8 during the second quarter compared with 1.7 a year earlier.
- Netbacks, including realized hedging gains, were $18.74/bbl in the quarter, down 42% from the same period in 2015.

Conventional oil

- Total conventional oil production decreased 20% to 55,476 bbls/d in the second quarter of 2016 compared with the same quarter a year ago, primarily due to natural reservoir declines and the 2015 sale of Cenovus's royalty and fee land business. The divested assets contributed an average of 4,300 bbls/d of production in the second quarter of 2015.

- Operating costs were $14.00/bbl in the quarter, 9% lower than in the second quarter of 2015, primarily due to lower repairs and maintenance, chemical, electricity and workforce costs.

Natural gas

- Natural gas production averaged 399 million cubic feet per day (MMcf/d) in the second quarter of 2016, down 11% from the same period a year earlier, primarily due to expected natural declines and the company's 2015 sale of its royalty and fee land business.
- Operating costs fell 7% to $1.06 per thousand cubic feet (Mcf) in the quarter compared with the same period a year earlier.

Downstream

- Cenovus's Wood River Refinery in Illinois and Borger Refinery in Texas, which are jointly owned with the operator, Phillips 66, continued to have strong operational performance in the second quarter of 2016, including:
  - processing a combined average of 458,000 bbls/d gross of crude oil (100% utilization) compared with 441,000 bbls/d gross in the same period in 2015 (96% utilization)
  - producing a combined average of 483,000 bbls/d gross of refined products compared with 462,000 bbls/d gross a year earlier.
- Cenovus had operating cash flow of $193 million from refining and marketing in the quarter compared with $300 million in the second quarter of 2015. The company's refining operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's operating cash flow from refining and marketing would have been $107 million lower in the second quarter of 2016. In the second quarter of 2015, operating cash flow would have been $101 million lower on a LIFO reporting basis.

Financial

Corporate and financial information

- Operating cash flow was $541 million in the second quarter, down 42% from the same period a year earlier, largely due to lower oil and natural gas prices and sales volumes as well as reduced operating cash flow from refining and marketing, primarily due to lower market crack spreads.
- In the second quarter of 2016, Cenovus had capital spending of approximately $236 million, down 34% from a year earlier, with the bulk of the investment going towards the company's oil sands operations. Capital investment in Cenovus's oil sands crude oil operations was $138 million, 47% lower than in the same period of 2015. Investment in conventional oil was $32 million in the second quarter, 6% lower than in the same quarter in 2015, while refining and marketing investment was $53 million, a 10% increase, due in part to the debottlenecking project at the Wood River Refinery. Capital investment in natural gas was $3 million in the second quarter, compared with $2 million in the year-earlier period.
- For the quarter, operating cash flow in excess of capital invested was $74 million from Cenovus's conventional oil business and $7 million from natural gas. Operating cash

flow from refining and marketing exceeded capital investment by $140 million, while operating cash flow from the company's oil sands crude oil operations exceeded capital spending by $94 million.

- After investing approximately $236 million during the second quarter, Cenovus had free cash flow of $204 million compared with free cash flow of $120 million in the same period a year earlier.
- Net loss was $267 million in the second quarter compared with net income of $126 million in the same period of 2015. The loss was primarily due to a decline in operating earnings, unrealized risk management losses of $284 million in the second quarter of 2016 compared with unrealized losses of $151 million in the second quarter of 2015, and non-operating unrealized foreign exchange losses of $18 million compared with unrealized gains of $99 million in the year-earlier period.
- G&A expenses were $94 million in the quarter, 22% higher than in the same period of 2015. The increase was primarily due to recorded severance costs of approximately $19 million and a non-cash expense of $17 million related to office building leases in Calgary in excess of Cenovus's current and near-term requirements.
- At June 30, 2016, the company's net debt to capitalization was 17% and net debt to adjusted EBITDA was 1.9 times. The debt to capitalization ratio was 34% and debt to adjusted EBITDA was 4.8 times. Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and debt to adjusted EBITDA of between 1.0 and 2.0 times. The company expects these ratios may be outside of the target ranges at different points in the economic cycle.
- The Board of Directors has declared a third-quarter dividend of $0.05 per share, payable on September 30, 2016 to common shareholders of record as of September 15, 2016. Based on the July 27, 2016 closing share price on the Toronto Stock Exchange of $17.50, this represents an annualized yield of about 1.1%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis. Over the long term, Cenovus intends to target a meaningful dividend that is sustainable when prices are at the bottom of the commodity cycle. Increases in the dividend would be considered with sustained improvements in the company's margins and production base.

Commodity price hedging

- Since the release of its first quarter earnings statement on April 27, 2016, Cenovus has added the following hedges for the period 2016 through 2018:
    - for July through December 2016, 30,000 bbls/d of WTI collars with a floor price of US$45.39/bbl
    - for January through June 2017, 17,000 bbls/d of WTI swaps at US$48.97/bbl
    - for July through December 2017, 25,000 bbls/d of WTI collars with a floor price of US$44.10/bbl
    - for July through December 2017, 10,000 bbls/d of Brent swaps at US$53.09/bbl
    - for January through June 2018, 10,000 bbls/d of Brent swaps at US$54.06/bbl
- As of today, the company has approximately 32% of its oil production hedged for the remainder of 2016 at a volume-weighted average floor price of C$63.38/bbl.
- In the second quarter of 2016, Cenovus had realized after-tax hedging losses of $5 million as the company's contract prices trailed average benchmark prices. Cenovus had unrealized after-tax hedging losses of $207 million during the quarter.

- Including hedging, market access commitments and downstream integration largely provided by the company's two U.S. refineries, Cenovus has positioned itself to mitigate the impact of swings in the Canadian light-heavy oil price differential for more than 85% of its anticipated 2016 heavy oil production. Together, these mechanisms help to support Cenovus's financial resilience during this challenging period for the industry.

Other developments

- Across Cenovus's operations, staff successfully demonstrated their commitment to safety by achieving more than 50 days without a recordable injury during the second quarter, the first time the company reached this milestone.
- In the second quarter, *Corporate Knights* magazine named Cenovus as one of the 50 Best Corporate Citizens in Canada for 2015, the fourth consecutive year the company has been included in the listing.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated July 27, 2016, should be read in conjunction with our June 30, 2016 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2015 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 27, 2016, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, 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 interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with shares listed on the Toronto and New York stock exchanges. On June 30, 2016, we had a market capitalization of approximately $15 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production for the six months ended June 30, 2016 was 197,815 barrels per day and our average natural gas production was 403 MMcf per day. Our refineries processed an average of 446,000 gross barrels per day of crude oil feedstock into an average of 472,000 gross barrels per day of refined products.

Our Operations

Oil Sands

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

	Six Months Ended June 30, 2016		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	**50**	**62,713**	**125,426**
Christina Lake	**50**	**77,577**	**155,154**
Narrows Lake	**50**	**-**	**-**
Emerging Projects			
Telephone Lake	**100**	**-**	**-**
Grand Rapids	**100**	**-**	**-**

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

	Six Months Ended June 30, 2016	
($ millions)	Crude Oil	Natural Gas
Operating Cash Flow	**277**	**1**
Capital Investment	**365**	**1**
Operating Cash Flow Net of Related Capital Investment	**(88)**	**-**

Conventional

Crude oil production from our Conventional business segment continues to generate dependable near-term cash flow. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations and provides cash flow to help fund our growth opportunities.

	Six Months Ended June 30, 2016	
($ millions)	**Crude Oil** [(1)]	**Natural Gas**
Operating Cash Flow	**194**	**43**
Capital Investment	**69**	**4**
Operating Cash Flow Net of Related Capital Investment	**125**	**39**

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

($ millions)	**Six Months Ended June 30, 2016**
Operating Cash Flow	**170**
Capital Investment	**105**
Operating Cash Flow Net of Related Capital Investment	**65**

QUARTERLY HIGHLIGHTS

In the second quarter, crude oil prices continued to be volatile with West Texas Intermediate ("WTI") reaching US$50 per barrel for the first time in almost a year. While crude oil prices improved from the first quarter of 2016, our companywide netback in the first half of 2016 was $5.84 per BOE, before realized risk management activities, which remains significantly lower than in prior years. As a result, we continue to focus on maintaining our financial resilience and safe and reliable operations. We are on track to reduce our planned 2016 capital, operating, general and administrative spending by approximately $500 million, relative to our original budget released in December 2015. Our ongoing efforts to reduce costs have helped our balance sheet remain strong, with approximately $3.8 billion of cash on hand at June 30, 2016.

Consistent with the improvement in crude oil benchmark prices, our average realized crude oil price more than doubled from the first quarter of 2016 to $33.87 per barrel in the second quarter of 2016. However, this was 32 percent lower than our average realized price in the second quarter of 2015.

In the second quarter, we:

- Decreased our total crude oil operating costs by 22 percent or $48 million, compared with 2015;
- Realized crude oil and natural gas netbacks, before risk management gains, of $15.48 per barrel (2015 – $28.76 per barrel) and $0.30 per Mcf (2015 – $1.53 per Mcf), respectively;
- Achieved Cash Flow of $440 million, a significant increase from the first quarter of 2016 primarily due to higher commodity prices;
- Incurred Operating Losses of $39 million or $1.65 per barrel of crude oil equivalent sold compared with Operating Earnings of $151 million or $6.11 per barrel of crude oil equivalent in the second quarter of 2015;
- Implemented workforce reductions identified in the first quarter, which resulted in an 11 percent reduction from our workforce at December 31, 2015; and
- Continued to progress our two oil sands expansion phases which is expected to add 80,000 gross barrels per day of production capacity.

OPERATING RESULTS

Total crude oil production declined in the three and six months ended June 30, 2016, as higher production from our Oil Sands segment was more than offset by lower production from our Conventional properties.

Crude Oil Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
(barrels per day)	**2016**	**Percent Change**	2015	**2016**	**Percent Change**	2015
Oil Sands						
Foster Creek	**64,544**	**11%**	58,363	**62,713**	**(1)%**	63,106
Christina Lake	**78,060**	**8%**	72,371	**77,577**	**4%**	74,410
	142,604	**9%**	130,734	**140,290**	**2%**	137,516
Conventional						
Heavy Oil	**28,500**	**(21)%**	36,099	**29,873**	**(18)%**	36,624
Light and Medium Oil	**26,177**	**(18)%**	31,809	**26,649**	**(20)%**	33,463
NGLs [(1)]	**799**	**(39)%**	1,312	**1,003**	**(25)%**	1,335
	55,476	**(20)%**	69,220	**57,525**	**(19)%**	71,422
Total Crude Oil Production	**198,080**	**(1)%**	199,954	**197,815**	**(5)%**	208,938

(1) NGLs include condensate volumes.

Production at Foster Creek was higher in the second quarter of 2016 compared with 2015 primarily due to a nearby forest fire reducing production by approximately 10,500 barrels per day in the second quarter of 2015. Production in the second quarter of 2016 benefited from new wells brought online in the second quarter. Production in the first half of the year was slightly lower than in 2015. Production in the first quarter of 2016 was impacted by a higher than average number of wells down for servicing, which have since been brought back online, and improved wellbore conformance during 2015 that accelerated production from more mature wells.

Production from Christina Lake increased in the three and six months ended June 30, 2016 due to additional wells and reliable performance of our facilities.

We successfully drilled four extended-reach horizontal wells at Foster Creek. The wells had an average horizontal length of over 1,600 meters. Longer horizontal wells can access a greater portion of the reservoir, potentially reducing development costs.

Thanks to the continued focus and safety leadership of teams working at our upstream and downstream operations, we operated for over 50 days without a recordable injury. This is the first time Cenovus has reached this milestone, demonstrating the commitment of our staff to working safely.

Our Conventional crude oil production decreased by 20 percent in the second quarter and 19 percent on a year-to-date basis due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in July 2015. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015 and 4,500 barrels per day on a year-to-date basis. In addition, production at Pelican Lake was shut-down for two days as a safety precaution due to a nearby forest fire; there was no damage to our facilities. Lost production has been estimated at approximately 650 barrels per day for the quarter.

Natural Gas Production Volumes

	Three Months Ended June 30,		Six Months Ended June 30,	
(MMcf per day)	**2016**	2015	**2016**	2015
Conventional	**381**	429	**386**	436
Oil Sands	**18**	21	**17**	20
	399	450	**403**	456

In the second quarter and on a year-to-date basis, our natural gas production declined 11 percent and 12 percent, respectively. Production decreased primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business.

Operating Netbacks

	Three Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Six Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Price [2]	**33.87**	49.48	**1.53**	2.82	**24.79**	39.90	**1.92**	2.94
Royalties	**1.94**	2.86	**0.04**	0.03	**1.42**	1.97	**0.07**	0.04
Transportation and Blending [2]	**6.53**	5.24	**0.13**	0.10	**6.19**	5.27	**0.12**	0.11
Operating Expenses [3]	**9.76**	12.29	**1.06**	1.14	**10.43**	12.60	**1.15**	1.20
Production and Mineral Taxes	**0.16**	0.33	**-**	0.02	**0.14**	0.27	**-**	0.01
Netback Excluding Realized Risk Management [4]	**15.48**	28.76	**0.30**	1.53	**6.61**	19.79	**0.58**	1.58
Realized Risk Management Gain (Loss)	**1.97**	1.75	**-**	0.39	**5.11**	4.27	**-**	0.34
Netback Including Realized Risk Management	**17.45**	30.51	**0.30**	1.92	**11.72**	24.06	**0.58**	1.92

(1) *Includes NGLs.*
(2) *The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was $19.76 per barrel for the second quarter (2015 – $22.58 per barrel) and $19.91 per barrel for the six months ended June 30, 2016 (2015 – $22.43 per barrel).*
(3) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*
(4) *The netbacks do not reflect non-cash write-downs of product inventory.*

Consistent with the decline in benchmark prices and widening heavy oil differentials, our average crude oil netback in the three and six months ended June 30, 2016, excluding realized risk management gains and losses, decreased compared with 2015. Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark due to transportation between market hubs and field locations, partially offset by the impact of inventory timing in a rising price environment. In the second quarter we experienced some of the benefit of using condensate purchased at a lower price earlier in the year.

The weakening of the Canadian dollar on a year-to-date basis, compared with 2015, had a positive impact on our crude oil price of approximately $1.77 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

In the second quarter, crude utilization increased due to consistent performance of both the Wood River and Borger refineries. In the second quarter of 2015, unplanned outages at our Borger refinery resulted from process unit outages and a power interruption.

On a year-to-date basis, crude utilization increased. Consistent performance in the current quarter was slightly offset by planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at the Borger refinery.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	**Percent Change**	2015	**2016**	**Percent Change**	2015
Crude Oil Runs [1] (Mbbls/d)	**458**	**4%**	441	**446**	**1%**	440
Heavy Crude Oil [1]	**228**	**14%**	200	**235**	**12%**	210
Refined Product [1] (Mbbls/d)	**483**	**5%**	462	**472**	**2%**	465
Crude Utilization [1] (percent)	**100**	**4%**	96	**97**	**1%**	96

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

Operating Cash Flow from Refining and Marketing in the three and six months ending June 30, 2016 was $193 million and $170 million, respectively. Operating Cash Flow was lower compared with 2015 primarily due to lower average market crack spreads and higher operating costs, partially offset by higher utilization rates, improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and widening heavy and medium crude oil differentials.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

	Six Months Ended June 30,					
	2016	**Percent Change**	2015	**Q2 2016**	Q1 2016	Q2 2015
Crude Oil Prices (US$/bbl)						
Brent						
Average	**41.03**	**(31)%**	59.33	**46.97**	35.08	63.50
End of Period	**49.68**	**(22)%**	63.59	**49.68**	39.60	63.59
WTI						
Average	**39.52**	**(26)%**	53.29	**45.59**	33.45	57.94
End of Period	**48.33**	**(19)%**	59.47	**48.33**	38.34	59.47
Average Differential Brent-WTI	**1.51**	**(75)%**	6.04	**1.38**	1.63	5.56
WCS (2)						
Average	**25.75**	**(36)%**	40.13	**32.29**	19.21	46.35
End of Period	**35.79**	**(26)%**	48.14	**35.79**	26.75	48.14
Average Differential WTI-WCS	**13.77**	**5%**	13.16	**13.30**	14.24	11.59
Condensate (C5 @ Edmonton) (3)						
Average	**39.23**	**(24)%**	51.78	**44.07**	34.39	57.94
Average Differential WTI-Condensate (Premium)/Discount	**0.29**	**(81)%**	1.51	**1.52**	(0.94)	-
Average Differential WCS-Condensate (Premium)/Discount	**(13.48)**	**16%**	(11.65)	**(11.78)**	(15.18)	(11.59)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**53.12**	**(25)%**	71.21	**64.25**	42.00	79.96
Chicago Ultra-low Sulphur Diesel ("ULSD")	**51.98**	**(29)%**	73.12	**59.40**	44.55	75.92
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	**13.36**	**(28)%**	18.65	**17.15**	9.58	20.77
Group 3	**11.78**	**(36)%**	18.40	**13.03**	10.52	19.34
Average Natural Gas Prices						
AECO (C$/Mcf)	**1.68**	**(40)%**	2.81	**1.25**	2.11	2.67
NYMEX (US$/Mcf)	**2.02**	**(28)%**	2.81	**1.95**	2.09	2.64
Basis Differential NYMEX-AECO (US$/Mcf)	**0.78**	**47%**	0.53	**0.99**	0.56	0.50
Foreign Exchange Rates (US$ per C$1)						
Average	**0.752**	**(7)%**	0.810	**0.776**	0.728	0.813

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

(2) *The average Canadian dollar WCS benchmark price for the second quarter of 2016 was $41.61 per barrel (2015 – $57.01 per barrel) and for the six months ended June 30, 2016 was $34.24 per barrel (2015 – $49.54 per barrel).*

(3) *The average Canadian dollar condensate benchmark price for the second quarter of 2016 was $56.79 per barrel (2015 – $71.27 per barrel) and for the six months ended June 30, 2016 was $52.17 per barrel (2015 – $63.93 per barrel).*

Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices improved from the first quarter of 2016 due to significant supply disruptions and strong demand. Although benchmark prices strengthened, crude oil prices remained approximately 26 percent lower than in the second quarter of 2015 due to excessive inventories. High inventory levels have been driven by the decision of the Organization of Petroleum Exporting Countries ("OPEC") to discontinue its role as the swing supplier of crude oil in response to U.S. production growth.

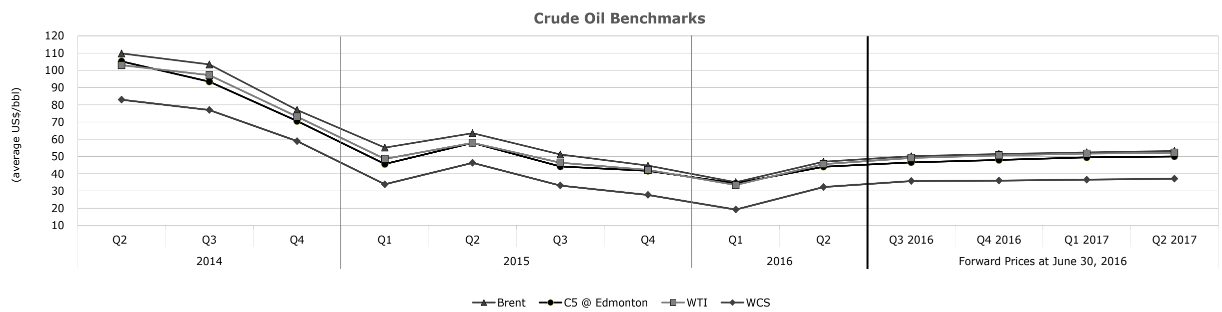
The global imbalance of crude oil supply and demand improved in the second quarter of 2016. Reductions in capital spending resulted in lower U.S. production compared with 2015. Prices also benefited from temporary supply disruptions in Canada and Nigeria, which offset strong production from Saudi Arabia and Iran. Demand growth remains positive due to higher than expected increases from the U.S., Europe and India. However, numerous concerns may limit near-term crude oil price increases. The risk of instability in the European Union, economic uncertainty in China, the resolution of supply outages or a resurgence in U.S. supply as producers quickly look to capitalize on any price rally, in combination with high inventory levels, are likely to discourage higher crude oil prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed compared with the second quarter of 2015 and on a year-to-date basis as a result of declining U.S. supply and the lifting of the U.S. export ban.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was wider in the second quarter of 2016 and on a year-to-date basis compared with 2015. The differential widened despite the steep decline in WTI compared with 2015 as U.S. domestic light oil supply declined and increased imports of global medium crude into the U.S. are expected to compete for coker capacity, pressuring heavy oil prices.

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

Average condensate prices were weaker relative to the WTI benchmark price in the second quarter of 2016 due to the Alberta forest fires reducing heavy oil production and the associated decline in diluent demand. In contrast, condensate was sold at par with WTI during the second quarter of 2015.

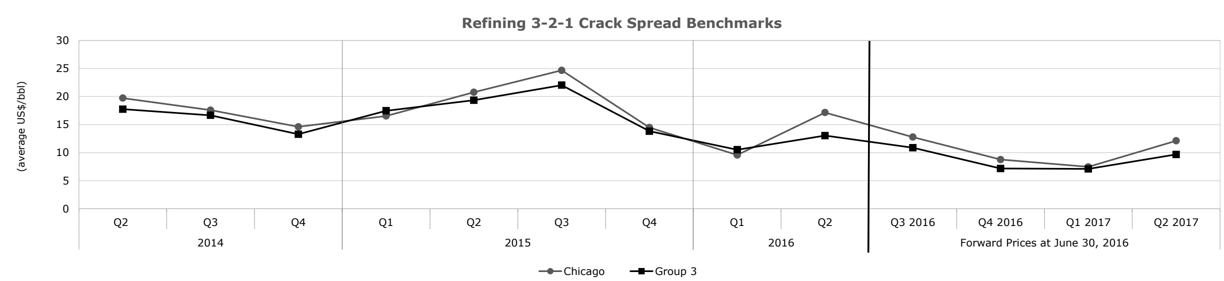


Refining Benchmarks

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

Average Chicago 3-2-1 crack spreads and Group 3 crack spreads decreased in the three and six months ended June 30, 2016, compared with 2015 due to higher global refined product inventory and strengthening of the WTI benchmark price compared with Brent, as evidenced by narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock, which is valued on a first in, first out ("FIFO") accounting basis.



Natural Gas Benchmarks

Average natural gas prices decreased in the second quarter of 2016 and on a year-to-date basis compared with 2015 primarily due to record-high storage levels in the U.S. and Canada resulting from a warmer than normal winter and the resiliency of 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 weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the second quarter and on a year-to-date basis, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and the expectation of higher U.S. interest rates. The weakening of the Canadian dollar in the first half of the year, compared with 2015, had a positive impact of approximately $374 million on our revenues. As at June 30, 2016, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2015, which resulted in $395 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

While crude oil prices improved from the first quarter of 2016, they were considerably lower than in the second quarter of 2015 and continued to have a significant impact on our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	2016 Q2	2016 Q1	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2
Revenues	**5,252**	6,867	**3,007**	2,245	2,924	3,273	3,726	3,141	4,238	4,970	5,422
Operating Cash Flow (1) (2)	**685**	1,480	**541**	144	357	602	932	548	537	1,156	1,305
Cash Flow (1)	**466**	972	**440**	26	275	444	477	495	401	985	1,189
Operating Earnings (Loss) (1)	**(462)**	63	**(39)**	(423)	(438)	(28)	151	(88)	(590)	372	473
Per Share – Diluted	**(0.55)**	0.08	**(0.05)**	(0.51)	(0.53)	(0.03)	0.18	(0.11)	(0.78)	0.49	0.62
Net Earnings (Loss)	**(385)**	(542)	**(267)**	(118)	(641)	1,801	126	(668)	(472)	354	615
Per Share – Basic and Diluted	**(0.46)**	(0.67)	**(0.32)**	(0.14)	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47	0.81
Capital Investment (3)	**559**	886	**236**	323	428	400	357	529	786	750	686
Dividends											
Cash Dividends	**83**	263	**42**	41	132	133	125	138	201	201	201
In Shares from Treasury	**-**	182	**-**	-	-	-	98	84	-	-	-
Per Share	**0.10**	0.5324	**0.05**	0.05	0.16	0.16	0.2662	0.2662	0.2662	0.2662	0.2662

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2015	**3,726**	**6,867**
Increase (Decrease) due to:		
Oil Sands	**(169)**	**(428)**
Conventional	**(221)**	**(389)**
Refining and Marketing	**(308)**	**(816)**
Corporate and Eliminations	**(21)**	**18**
Revenues for the Periods Ended June 30, 2016	**3,007**	**5,252**

Combined Oil Sands and Conventional revenues declined 29 percent in the second quarter and 33 percent on a year-to-date basis, compared with 2015, due to lower commodity prices and reduced sales volumes, partially offset by weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues. These declines were partially offset by lower royalties.

Revenues from our Refining and Marketing segment in the three and six months ended June 30, 2016 decreased 13 percent and 18 percent, respectively. 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 weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group in the second quarter of 2016 increased from 2015 as higher purchased crude oil and natural gas volumes were partially offset by lower sales prices. On a year-to-date basis, marketing revenues decreased compared with 2015 due to lower sales prices, partially offset by higher purchased crude oil and natural gas volumes.

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

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

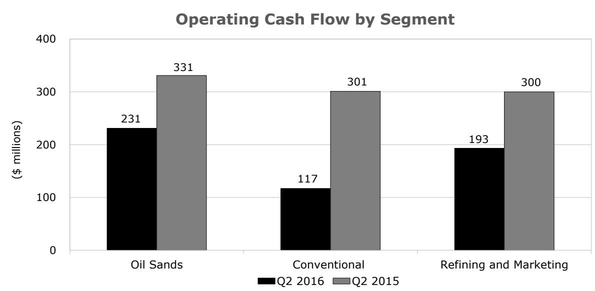
Operating Cash Flow

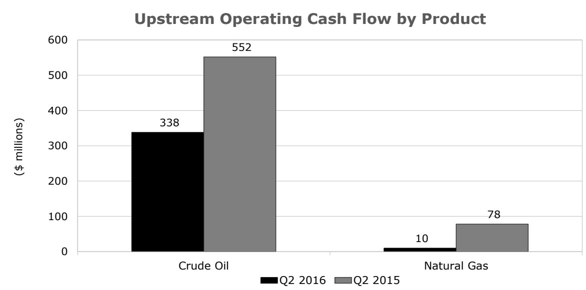
Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**3,096**	3,794	**5,408**	7,041
(Add) Deduct:				
Purchased Product	**1,712**	1,976	**3,140**	3,814
Transportation and Blending	**440**	498	**891**	1,026
Operating Expenses (1)	**393**	428	**845**	907
Production and Mineral Taxes	**3**	6	**5**	11
Realized (Gain) Loss on Risk Management Activities	**7**	(46)	**(158)**	(197)
Operating Cash Flow	**541**	932	**685**	1,480

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

Three Months Ended June 30, 2016 Compared With June 30, 2015





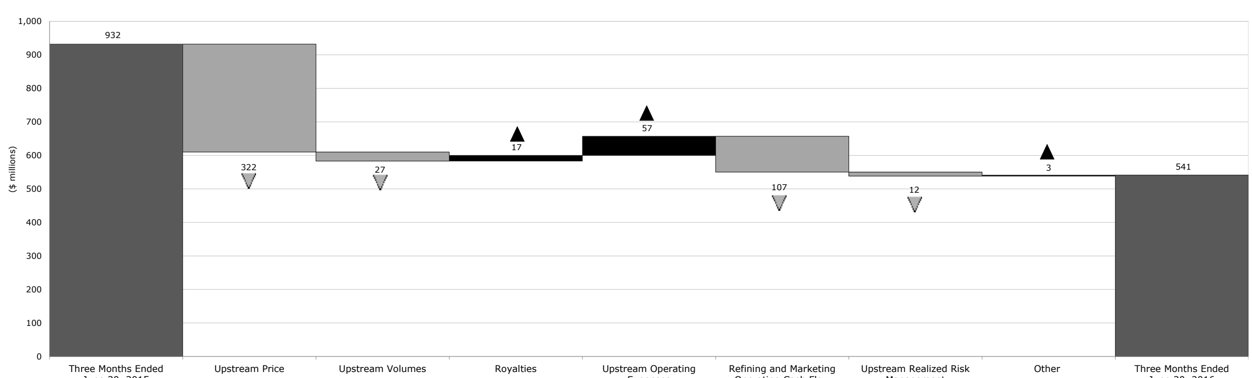
Operating Cash Flow declined 42 percent in the second quarter of 2016 compared with 2015 primarily due to:

- A 32 percent decrease in our average crude oil sales price and a 46 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of lower average market crack spreads and higher operating costs, partially offset by higher utilization rates, improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and widening heavy and medium crude oil differentials; and
- A two percent decline in our crude oil sales volumes as well as an 11 percent decline in natural gas sales volumes.

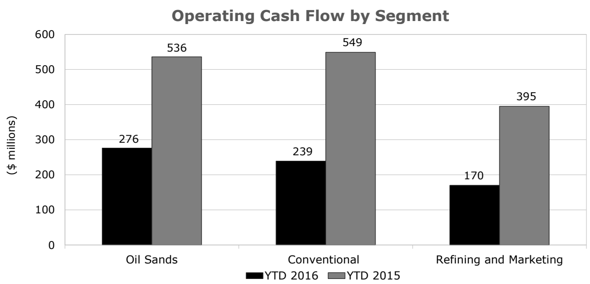
These declines in Operating Cash Flow were partially offset by:

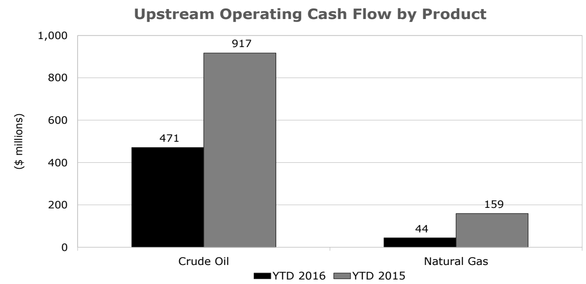
- A $58 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and transportation costs; and
- A $48 million decrease in crude oil operating expenses primarily due to lower fuel costs, repairs and maintenance activities, chemicals, electricity, workforce reductions, and workover activities.

Operating Cash Flow Variance



Six Months Ended June 30, 2016 Compared With June 30, 2015





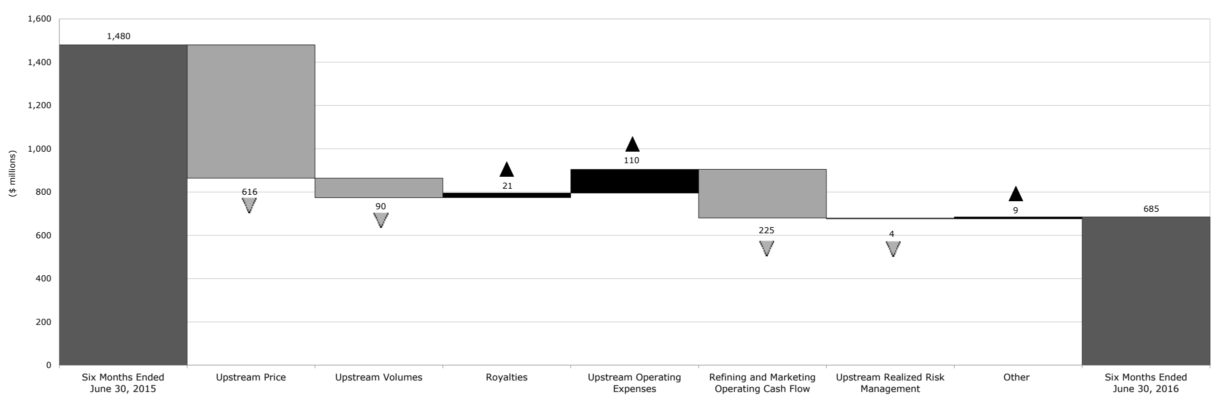
Operating Cash Flow declined 54 percent in the first six months of 2016 compared with 2015 primarily due to:

- A 38 percent decrease in our average crude oil sales price and a 35 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of lower average market crack spreads and higher operating costs, partially offset by improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and higher utilization rates; and
- A five percent decrease in our crude oil sales volume and a 12 percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- A $133 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and higher transportation costs;
- A $97 million decrease in crude oil operating expenses primarily due to workforce reductions, lower chemical costs, decreased repairs and maintenance costs, a reduction in fuel costs due to lower natural gas prices and a decline in workover activities; and
- A $21 million decline in royalties primarily due to a decrease in crude oil sales prices.

Operating Cash Flow Variance



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

Cash Flow

Cash Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Cash From Operating Activities	**205**	335	**387**	610
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(17)**	(14)	**(46)**	(68)
Net Change in Non-Cash Working Capital	**(218)**	(128)	**(33)**	(294)
Cash Flow	**440**	477	**466**	972

In the three and six months ended June 30, 2016, Cash Flow decreased primarily due to lower Operating Cash Flow, as discussed above, partially offset by a current income tax recovery.

Operating Earnings (Loss)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Earnings (Loss), Before Income Tax	**(348)**	180	**(683)**	(601)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**284**	151	**433**	296
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**18**	(99)	**(395)**	415
(Gain) Loss on Divestiture of Assets	**1**	-	**1**	(16)
Operating Earnings (Loss), Before Income Tax	**(45)**	232	**(644)**	94
Income Tax Expense (Recovery)	**(6)**	81	**(182)**	31
Operating Earnings (Loss)	**(39)**	151	**(462)**	63

(1) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(2) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

Operating Earnings declined in the three and six months ended June 30, 2016 compared with 2015 primarily due to lower Cash Flow, as discussed above, the recognition of a non-cash expense of $17 million ($31 million on a year-to-date basis) in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements and a larger deferred income tax recovery in the prior periods, partially offset by lower depreciation, depletion and amortization ("DD&A").

Net Earnings

($ millions)	Three Months Ended	Six Months Ended
Net Earnings (Loss) for the Periods Ended June 30, 2015	**126**	**(542)**
Increase (Decrease) due to:		
Operating Cash Flow (1) (2)	**(391)**	**(795)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(133)**	**(137)**
Unrealized Foreign Exchange Gain (Loss)	**(120)**	**812**
Gain (Loss) on Divestiture of Assets	**(1)**	**(17)**
Expenses (2) (3)	**(19)**	**(37)**
Depreciation, Depletion and Amortization	**115**	**72**
Exploration Expense	**21**	**20**
Income Tax Recovery	**135**	**239**
Net Earnings (Loss) for the Periods Ended June 30, 2016	**(267)**	**(385)**

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Net Earnings for the three months ended June 30, 2016 decreased primarily due to:

- A decline in Operating Earnings, as discussed above;
- Unrealized risk management losses of $284 million in the quarter compared with unrealized losses of $151 million in the second quarter of 2015; and
- Non-operating unrealized foreign exchange losses of $18 million related to the translation of our U.S. dollar denominated debt compared with unrealized gains of $99 million in 2015.

These decreases were partially offset by a higher deferred income tax recovery in 2016 primarily due to the impact of unrealized risk management losses.

Net Earnings improved for the six months ended June 30, 2016 primarily due to non-operating unrealized foreign exchange gains of $395 million compared with unrealized losses of $415 million in 2015 and a higher deferred income tax recovery. These increases were partially offset by a decline in Operating Earnings, as discussed above, and unrealized risk management losses of $433 million on a year-to-date basis compared with unrealized losses of $296 million in 2015.

Net Capital Investment

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Oil Sands	**139**	260	**366**	674
Conventional	**34**	36	**73**	102
Refining and Marketing	**53**	48	**105**	92
Corporate and Eliminations	**10**	13	**15**	18
Capital Investment	**236**	357	**559**	886
Acquisitions	**11**	-	**11**	-
Divestitures	**-**	-	**-**	(16)
Net Capital Investment (1)	**247**	357	**570**	870

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

Capital investment in the three and six months ended June 30, 2016 declined 34 percent and 37 percent respectively, 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 work to complete the phase G expansion at Foster Creek and the Christina Lake expansion phase F. Conventional capital investment focused on maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn.

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

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

Capital Investment Decisions

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

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

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

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Cash Flow (1)	**440**	477	**466**	972
Capital Investment (Sustaining and Growth)	**236**	357	**559**	886
Free Cash Flow (2)	**204**	120	**(93)**	86
Cash Dividends	**42**	125	**83**	263
	162	(5)	**(176)**	(177)

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

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

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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

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

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

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

Revenues by Reportable Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Oil Sands	**706**	875	**1,176**	1,604
Conventional	**261**	482	**515**	904
Refining and Marketing	**2,129**	2,437	**3,717**	4,533
Corporate and Eliminations	**(89)**	(68)	**(156)**	(174)
	3,007	3,726	**5,252**	6,867

OIL SANDS

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

Significant developments in our Oil Sands segment in the second quarter of 2016 compared with 2015 include:

- Crude oil netbacks, excluding realized risk management activities, of $14.43 per barrel, a 47 percent decrease from the second quarter of 2015;
- Decreasing our crude oil operating costs by $20 million or $2.51 per barrel to $8.06 per barrel;
- Higher production at Foster Creek by 11 percent to an average of 64,544 barrels per day; and
- Reducing capital investment by $121 million.

Oil Sands – Crude Oil

Three Months Ended June 30, 2016 Compared With June 30, 2015

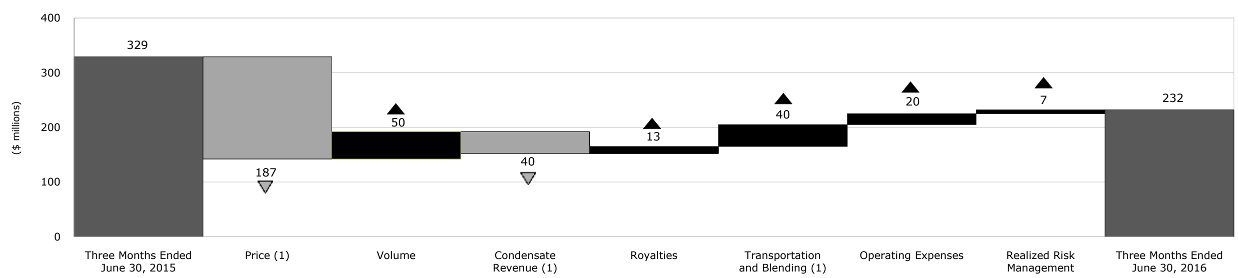
Financial Results

($ millions)	Three Months Ended June 30, 2016	2015
Gross Sales	**707**	884
Less: Royalties	**3**	16
Revenues	**704**	868
Expenses		
Transportation and Blending	**395**	435
Operating [(1)]	**101**	121
(Gain) Loss on Risk Management	**(24)**	(17)
Operating Cash Flow	**232**	329
Capital Investment	**138**	260
Operating Cash Flow Net of Related Capital Investment	**94**	69

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

When capital investment exceeds Operating Cash Flow from Oil Sands, it is funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

Operating Cash Flow Variance



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

Revenues

Pricing

In the second quarter, our average realized crude oil sales price was $30.59 per barrel. While our average price improved from the first quarter price of $10.13 per barrel, it was 33 percent lower than in the second quarter of 2015. The decline in our realized crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices. Weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market, which generally secure a higher sales price, positively impacted our realized sales prices.

Our realized bitumen price is influenced by the cost of condensate used in blending. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen price declines. In addition, our cost for condensate is generally higher than benchmark due to transportation between market hubs and field locations, partially offset by the impact of inventory timing in a rising price environment.

The WCS-CDB differential widened to a discount of US$2.64 per barrel (2015 – discount of US$2.00 per barrel). In the second quarter, 90 percent of our Christina Lake production was sold as CDB (2015 – 88 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	Three Months Ended June 30, 2016	Percent Change	2015
Foster Creek	**64,544**	**11%**	58,363
Christina Lake	**78,060**	**8%**	72,371
	142,604	**9%**	130,734

Production at Foster Creek was higher compared with 2015 primarily due to an 11-day precautionary shut-down in the second quarter of 2015 due to a nearby forest fire, which reduced production by approximately 10,500 barrels per day. Production in the second quarter of 2016 benefited from new wells that were brought online in the second quarter.

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

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential during the second quarter, the proportion of the cost of condensate recovered 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 realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. The royalty calculation was based on gross revenues as compared with a calculation based on net profits for 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

	Three Months Ended June 30,	
(percent)	**2016**	2015
Foster Creek	**1.0**	5.0
Christina Lake	**1.2**	2.5

Royalties decreased $13 million in the second quarter relative to the same period in 2015, primarily due to the decline in crude oil sales prices, partially offset by an increase in sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs decreased $40 million or nine percent. Blending costs declined primarily as a result of lower condensate prices partially offset by higher condensate volumes from increased production. Our condensate costs were higher than the average benchmark price in the second quarter due to the transportation expense associated with moving the condensate to our oil sands projects. However, we experienced some of the benefit of using condensate purchased at a lower price earlier in the year.

Transportation costs increased due to tariffs from additional sales to the U.S. market, which generally secure higher sales prices, and shipping higher volumes due to increased production. Additionally, costs increased due to charges associated with capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Transportation costs also increased as a result of moving higher volumes by rail in the current quarter compared with 2015. We transported an average of 10,810 gross barrels per day of crude oil by rail, consisting of 16 unit train shipments (2015 – 5,210 gross barrels per day, eight unit train shipments). The 16 unit trains were loaded at our crude-by-rail terminal, located in Bruderheim, Alberta.

Operating

Primary drivers of our operating expenses for the second quarter were workforce, fuel, chemical costs, repairs and maintenance, and workovers. Total operating expenses decreased $20 million primarily as a result of lower natural gas prices that reduced fuel costs, lower repairs and maintenance activities, lower electrical costs and workforce reductions.

Per-unit Operating Expenses

($/bbl)	Three Months Ended June 30, 2016	Percent Change	2015
Foster Creek			
Fuel	**1.64**	**(41)%**	2.78
Non-fuel [1]	**8.51**	**(19)%**	10.51
Total	**10.15**	**(24)%**	13.29
Christina Lake			
Fuel	**1.42**	**(35)%**	2.18
Non-fuel [1]	**4.93**	**(18)%**	6.02
Total	**6.35**	**(23)%**	8.20
Total	**8.06**	**(24)%**	10.57

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

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

- Lower repairs and maintenance costs due to a focus on critical operational activities;
- Higher production volumes; and
- A reduction in workover expenses due to fewer pump changes.

At Christina Lake, fuel costs decreased due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined due to higher production and recording a credit due to the revaluation of greenhouse gas credits because of regulation amendments, partially offset by additional fluid, waste handling and trucking costs from increased activity levels.

Operating Netbacks

	Foster Creek		Christina Lake	
	Three Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price [1]	**33.40**	48.25	**28.31**	43.36
Royalties	**0.23**	1.97	**0.28**	0.99
Transportation and Blending [1]	**11.44**	9.04	**4.90**	4.29
Operating Expenses [2]	**10.15**	13.29	**6.35**	8.20
Netback Excluding Realized Risk Management [3]	**11.58**	23.95	**16.78**	29.88
Realized Risk Management	**1.88**	0.54	**1.96**	2.21
Netback Including Realized Risk Management	**13.46**	24.49	**18.74**	32.09

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the second quarter was $24.76 per barrel (2015 – $29.82 per barrel) for Foster Creek, and $26.24 per barrel (2015 – $32.90 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) The netbacks do not reflect non-cash write-downs of product inventory.

Risk Management

Risk management activities in the second quarter resulted in realized gains of $24 million (2015 – $17 million), consistent with our contract prices exceeding average benchmark prices.

Six Months Ended June 30, 2016 Compared With June 30, 2015

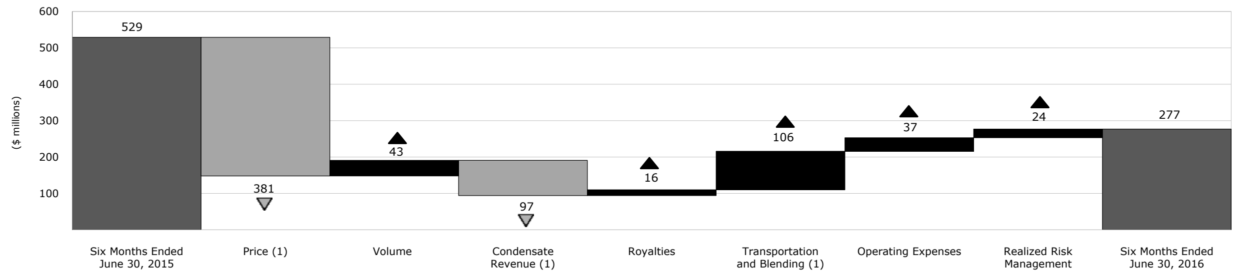
Financial Results

($ millions, unless otherwise noted)	Six Months Ended June 30, 2016	2015
Gross Sales	**1,172**	1,607
Less: Royalties	**3**	19
Revenues	**1,169**	1,588
Expenses		
Transportation and Blending	**799**	905
Operating [1]	**223**	260
(Gain) Loss on Risk Management	**(130)**	(106)
Operating Cash Flow	**277**	529
Capital Investment	**365**	673
Operating Cash Flow Net of Related Capital Investment	**(88)**	(144)

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

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Operating Cash Flow Variance



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

Revenues

Pricing

For the six months ended June 30, 2016, our average realized crude oil sales price was $20.28 per barrel, a 43 percent decrease from 2015. The decline in our realized crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market, which generally secure a higher sales price.

In the first half of 2016, 90 percent of our Christina Lake production was sold as CDB (2015 – 87 percent), with the remainder sold into the WCS stream.

Production Volumes

	Six Months Ended June 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Foster Creek	**62,713**	**(1)%**	63,106
Christina Lake	**77,577**	**4%**	74,410
	140,290	**2%**	137,516

Production at Foster Creek was slightly lower compared with 2015. In the second quarter of 2016, new wells were brought online and wells down for servicing early in 2016 were brought back online, partially offsetting the lower production in the first quarter. Production at Foster Creek in the first half of 2015 was reduced by approximately 5,300 barrels per day, net, due to an 11-day shut-down as a safety precaution due to a nearby forest fire.

Production from Christina Lake increased in the six months ended June 30, 2016 due to production from additional wells and improved performance of our facilities.

Royalties

Effective Royalty Rates

	Six Months Ended June 30,	
(percent)	**2016**	2015
Foster Creek	**0.3**	2.8
Christina Lake	**1.2**	2.7

Royalties decreased $16 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes.

At Foster Creek, low crude oil sales prices and the true-up of the 2015 royalty calculation decreased the overall royalty rate in the first half of 2016. In addition, we received regulatory approval in 2015 to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate. Excluding the credit, the effective royalty rate in 2015 for Foster Creek would have been 5.0 percent.

The Christina Lake royalty rate decreased in 2016 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $106 million or 12 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with higher production. Our condensate costs exceeded the average benchmark price in 2016 primarily due to the utilization of higher priced inventory and the transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased primarily due to tariffs from additional sales to the U.S. market, which generally secure higher sales prices, and shipping higher volumes due to increased production. Additionally, costs increased due to charges associated with capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

Lower volumes were moved by rail in the first half of 2016; however, rail costs increased slightly as we transported volumes across farther distances. We transported an average of 7,718 gross barrels per day of crude oil by rail, consisting of 23 unit train shipments (2015 – 8,522 gross barrels per day, 26 unit train shipments). The 23 unit trains were loaded at our crude-by-rail terminal, located in Bruderheim, Alberta.

Operating

Primary drivers of our operating expenses in the first half of 2016 were workforce, fuel, workovers, chemicals, and repairs and maintenance. Total operating expenses decreased $37 million primarily as a result of lower natural gas prices that reduced fuel costs, a decline in repairs and maintenance, and reduced workforce.

Per-unit Operating Expenses

	Six Months Ended June 30,		
($/bbl)	**2016**	**Percent Change**	2015
Foster Creek			
Fuel	**2.05**	**(29)%**	2.87
Non-fuel [1]	**9.04**	**(18)%**	11.04
Total	**11.09**	**(20)%**	13.91
Christina Lake			
Fuel	**1.70**	**(22)%**	2.18
Non-fuel [1]	**5.30**	**(12)%**	6.04
Total	**7.00**	**(15)%**	8.22
Total	**8.79**	**(19)%**	10.79

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

At Foster Creek, fuel costs decreased 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 primarily due to:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Workforce reductions; and
- A reduction in workover expenses due to lower costs associated with well servicing and fewer pump changes.

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

- Higher production;
- Recording a credit due to the revaluation of greenhouse gas credits because of regulation amendments;
- Lower chemical costs due to supply chain initiatives; and
- Reduced workforce costs.

These decreases were offset by higher workover costs due to more pump changes.

Operating Netbacks

($/bbl)	Foster Creek		Christina Lake	
	Six Months Ended June 30,			
	2016	2015	**2016**	2015
Price (1)	**22.78**	38.53	**18.33**	32.71
Royalties	**0.04**	0.82	**0.16**	0.79
Transportation and Blending (1)	**10.09**	9.22	**5.10**	4.22
Operating Expenses (2)	**11.09**	13.91	**7.00**	8.22
Netback Excluding Realized Risk Management (3)	**1.56**	14.58	**6.07**	19.48
Realized Risk Management	**5.63**	4.60	**4.77**	4.24
Netback Including Realized Risk Management	**7.19**	19.18	**10.84**	23.72

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was $25.44 per barrel (2015 – $30.21 per barrel) for Foster Creek, and $26.35 per barrel (2015 – $32.21 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

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

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

Risk Management

Risk management activities in the first six months of 2016 resulted in realized gains of $130 million (2015 – $106 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the three and six months ended June 30, 2016, net of internal usage, was 18 MMcf per day and 17 MMcf per day, respectively (2015 – 21 MMcf per day and 20 MMcf per day respectively).

Operating cash flow from our Oil Sands natural gas production was $nil in the second quarter (2015 – $1 million) and $1 million on a year-to-date basis (2015 – $4 million), declining primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Foster Creek	**68**	73	**157**	222
Christina Lake	**61**	161	**175**	368
	129	234	**332**	590
Narrows Lake	**1**	9	**5**	29
Telephone Lake	**3**	4	**10**	15
Grand Rapids	**1**	12	**6**	26
Other (1)	**5**	1	**13**	14
Capital Investment (2)	**139**	260	**366**	674

(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 focused on sustaining capital related to existing production and drilling stratigraphic test wells in the first quarter to help identify well pad locations for sustaining wells and near-term expansion phases. Activity in the first half of the year also related to Foster Creek expansion phase G and Christina Lake expansion phase F, both of which remain on track. Capital investment declined in the second quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment. Lower capital investment at Christina Lake is also attributable to the completion of the optimization project in 2015.

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

Emerging Projects

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

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

Drilling Activity [(1)]

	Gross Stratigraphic Test Wells [(2)]		Gross Production Wells [(3)]	
Six Months Ended June 30,	**2016**	2015	**2016**	2015
Foster Creek	**95**	122	**11**	10
Christina Lake	**97**	36	**19**	33
	192	158	**30**	43
Grand Rapids	**-**	-	**-**	1
Other	**5**	-	**-**	-
	197	158	**30**	44

(1) We did not drill any gross service wells in the six months ended June 30, 2016 (2015 – five gross service wells).
(2) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the first half of 2016, no wells were drilled using our SkyStrat™ drilling rig (2015 – seven wells).
(3) SAGD well pairs are counted as a single producing well.

Future Capital Investment

We have adopted a more moderate and staged approach to future oil sands expansions due to the low commodity price environment.

Existing Projects

Foster Creek is currently producing from phases A through F, with some initial capacity in phase G becoming available late in the second quarter. Capital investment for 2016 is forecast to be between $280 million and $310 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between $280 million and $310 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016, with ramp-up to design capacity expected to take 12 to 18 months. Construction work on phase G was deferred in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

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

Emerging Projects

Capital investment for our new resource plays is forecast to be between $35 million and $45 million in 2016.

Depreciation, Depletion & Amortization

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

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

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

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $13.50 to $14.50 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the three and six months ended June 30 2016, Oil Sands DD&A decreased $2 million and $24 million, respectively, primarily due to lower DD&A rates partially offset by higher sales volumes. The average depletion rate for the first six months of 2016 was approximately $11.55 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake.

CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO_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 flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

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

- Crude oil and natural gas netbacks, excluding realized risk management activities, of $18.06 per barrel (2015 – $31.69 per barrel) and $0.28 per Mcf (2015 – $1.59 per Mcf), respectively;
- Crude oil production averaging 55,476 barrels per day, decreasing 20 percent due to natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015;
- Reducing our crude oil operating costs by $28 million. Operating costs per barrel decreased nine percent due to lower repairs and maintenance and workover activities, chemical consumption, electricity prices and workforce reductions; and
- Generating Operating Cash Flow net of capital investment of $83 million, a decrease of 69 percent.

Conventional – Crude Oil

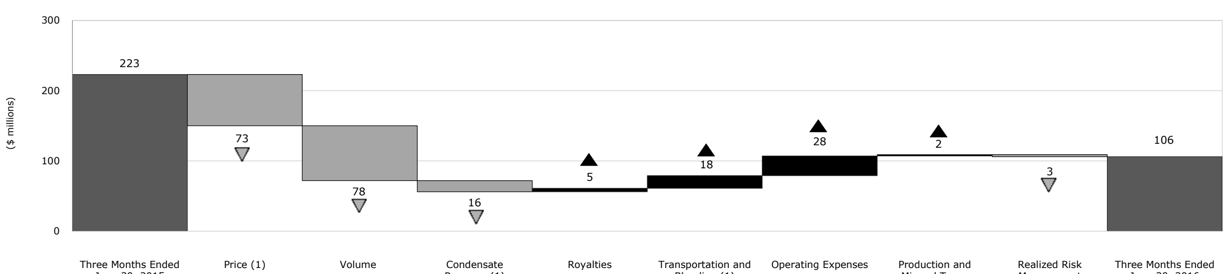
Three Months Ended June 30, 2016 Compared With June 30, 2015

Financial Results

($ millions)	Three Months Ended June 30, 2016	2015
Gross Sales	**239**	406
Less: Royalties	**31**	36
Revenues	**208**	370
Expenses		
Transportation and Blending	**40**	58
Operating (1)	**70**	98
Production and Mineral Taxes	**3**	5
(Gain) Loss on Risk Management	**(11)**	(14)
Operating Cash Flow	**106**	223
Capital Investment	**32**	34
Operating Cash Flow Net of Related Capital Investment	**74**	189

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

Operating Cash Flow Variance



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

Revenues

Pricing

Our 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 realized crude oil sales price averaged $42.03 per barrel in the second quarter, a 25 percent decrease from the second quarter of 2015, consistent with lower crude oil benchmark prices, net of applicable differentials. However, this is a 41 percent increase from the first quarter 2016 realized average price of $29.82 per barrel.

Production Volumes

	Three Months Ended June 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Heavy Oil	**28,500**	**(21)%**	36,099
Light and Medium Oil	**26,177**	**(18)%**	31,809
NGLs	**799**	**(39)%**	1,312
	55,476	**(20)%**	69,220

Crude oil production declined due to expected natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,300 barrels per day in the second quarter of 2015.

Production at Pelican Lake was shut-down for two days as a safety precaution due to a nearby forest fire; there was no damage to our facilities. Lost production has been estimated at approximately 650 barrels per day, for the quarter.

Condensate

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

Royalties

Royalties decreased in the second quarter primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. In the second quarter, the effective crude oil royalty rate for our Conventional properties was 15.5 percent (2015 – 10.2 percent).

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

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

Expenses

Transportation and Blending

Transportation and blending costs decreased $18 million. Blending costs declined due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in the volumes moved by rail, partially offset by additional costs due to pipeline capacity commitments in excess of our current production. We did not transport any volumes by rail in the second quarter of 2016 (2015 – 822 barrels per day).

Operating

Primary drivers of our operating expenses in the second quarter of 2016 were workforce, workovers, property taxes and lease costs, and electricity. Operating costs declined nine percent to $14.00 per barrel primarily due to:

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

These decreases were partially offset by lower production.

Operating Netbacks

	Heavy Oil		Light and Medium	
	Three Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price (1)	**36.77**	52.63	**48.09**	61.66
Royalties	**3.95**	5.34	**8.52**	5.67
Transportation and Blending (1)	**3.85**	3.09	**2.77**	3.06
Operating Expenses (2)	**12.34**	15.45	**16.21**	15.90
Production and Mineral Taxes	**0.01**	0.08	**1.18**	1.95
Netback Excluding Realized Risk Management (3)	**16.62**	28.67	**19.41**	35.08
Realized Risk Management	**2.12**	2.24	**2.09**	2.48
Netback Including Realized Risk Management	**18.74**	30.91	**21.50**	37.56

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $10.34 per barrel (2015 – $12.42 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) The netbacks do not reflect non-cash write-downs of product inventory.

Risk Management

Risk management activities for the second quarter resulted in realized gains of $11 million (2015 – realized gains of $14 million), consistent with our contract prices exceeding average benchmark prices.

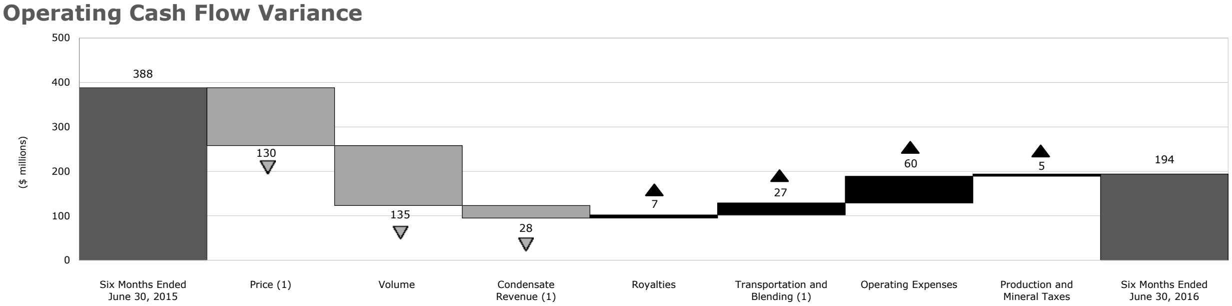
Six Months Ended June 30, 2016 Compared With June 30, 2015

Financial Results

	Six Months Ended June 30,	
($ millions)	**2016**	2015
Gross Sales	**428**	721
Less: Royalties	**48**	55
Revenues	**380**	666
Expenses		
Transportation and Blending	**84**	111
Operating (1)	**148**	208
Production and Mineral Taxes	**5**	10
(Gain) Loss on Risk Management	**(51)**	(51)
Operating Cash Flow	**194**	388
Capital Investment	**69**	96
Operating Cash Flow Net of Related Capital Investment	**125**	292

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

Operating Cash Flow Variance



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

Revenues

Pricing

Our average realized crude oil sales price decreased 26 percent to $35.73 per barrel consistent with the sustained decline in crude oil benchmark prices, net of applicable differentials.

Production Volumes

(barrels per day)	2016	Six Months Ended June 30, Percent Change	2015
Heavy Oil	**29,873**	**(18)%**	36,624
Light and Medium Oil	**26,649**	**(20)%**	33,463
NGLs	**1,003**	**(25)%**	1,335
	57,525	**(19)%**	71,422

Production declined primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 4,500 barrels per day in the first half of 2015.

Royalties

Royalties decreased $7 million primarily due to lower realized sales prices and a decrease in sales volumes partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business in 2015. In the first six months of 2016, the effective crude oil royalty rate for our Conventional properties was 14.3 percent (2015 – 9.0 percent). The Pelican Lake crown royalty calculation was based on net profits in both 2016 and 2015.

Production and mineral taxes decreased on a year-to-date basis, consistent with lower crude oil prices in 2016, 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 $27 million. Blending costs declined primarily due to lower condensate prices as well as a decrease in condensate volumes, consistent with lower production.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in volumes moved by rail, partially offset by additional costs due to pipeline capacity commitments in excess of our current production. In the first half of 2016, we did not transport any volumes by rail (2015 – 1,204 barrels per day).

Operating

Primary drivers of our operating expenses in the first six months of 2016 were workforce costs, workover activities, electricity, property taxes and lease costs, chemical consumption, and repairs and maintenance. Operating expenses declined $60 million or $1.49 per barrel.

The per unit decline was primarily due to:

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

These decreases were partially offset by lower production.

Operating Netbacks

	Heavy Oil		Light and Medium	
	Six Months Ended June 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price (1)	**31.15**	44.24	**41.12**	53.24
Royalties	**2.62**	3.84	**6.82**	4.55
Transportation and Blending (1)	**4.33**	3.25	**2.75**	2.97
Operating Expenses (2)	**13.19**	16.37	**16.28**	15.98
Production and Mineral Taxes	**-**	0.05	**1.00**	1.59
Netback Excluding Realized Risk Management (3)	**11.01**	20.73	**14.27**	28.15
Realized Risk Management	**5.17**	3.91	**5.04**	4.30
Netback Including Realized Risk Management	**16.18**	24.64	**19.31**	32.45

(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $10.19 per barrel (2015 – $11.96 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

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

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

Risk Management

Risk management activities in the first six months of the year resulted in realized gains of $51 million (2015 – realized gains of $51 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, **2016**	2015	Six Months Ended June 30, **2016**	2015
Gross Sales	**53**	111	**135**	233
Less: Royalties	**2**	1	**5**	3
Revenues	**51**	110	**130**	230
Expenses				
Transportation and Blending	**5**	4	**8**	9
Operating	**36**	43	**78**	90
Production and Mineral Taxes	**-**	1	**-**	1
(Gain) Loss on Risk Management	**-**	(15)	**1**	(25)
Operating Cash Flow	**10**	77	**43**	155
Capital Investment	**2**	2	**4**	6
Operating Cash Flow Net of Related Capital Investment	**8**	75	**39**	149

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

Three and Six Months Ended June 30, 2016 Compared With June 30, 2015

Revenues

Pricing

In the three and six months ended June 30, 2016, our average natural gas sales price decreased 46 percent to $1.52 per Mcf and 35 percent to $1.92 per Mcf, respectively. This is consistent with the decline in the AECO benchmark price.

Production

Production decreased by 11 percent to 381 MMcf per day in the second quarter and 386 MMcf per day on a year-to-date basis due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 14 MMcf and 17 MMcf per day, respectively, in the three and six months ended June 30, 2015.

Royalties

Royalties increased as a result of additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business, partially offset by lower prices and production declines. The average royalty rate in the second quarter was 4.1 percent (2015 – 1.1 percent) and 4.3 percent (2015 – 1.4 percent) on a year-to-date basis.

Expenses

Transportation

In the three and six months ended June 30, 2016, transportation costs were relatively consistent with 2015. Cost reductions due to the decline in sales volumes were offset by additional charges from a true-up of 2015 transportation contracts.

Operating

Primary drivers of our operating expenses in the three and six months ended June 30, 2016 were property taxes and lease costs, and workforce. Operating expenses decreased by $7 million and $12 million, respectively, primarily due to lower workforce costs, electricity due to lower pricing, and repairs and maintenance.

Risk Management

Risk management activities resulted in an impact of $nil in the second quarter and realized losses of $1 million on a year-to-date basis (2015 – gains of $15 million in the second quarter and $25 million on a year-to-date basis), consistent with average benchmark prices approaching our contract prices.

Conventional – Capital Investment

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Heavy Oil	**13**	10	**23**	32
Light and Medium Oil	**19**	24	**46**	64
Natural Gas	**2**	2	**4**	6
Capital Investment (1)	**34**	36	**73**	102

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

Capital investment in 2016 was primarily related to maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment declined in the first half of 2016 primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

Drilling Activity

(net wells, unless otherwise stated)	Six Months Ended June 30, 2016	2015
Crude Oil	**1**	5
Recompletions	**65**	120
Gross Stratigraphic Test Wells	**4**	-

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

Future Capital Investment

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

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

DD&A

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

Conventional DD&A decreased $116 million in the second quarter of 2016 due to a decline in sales volumes and lower DD&A rates. The average depletion rate decreased approximately 20 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined, in part, from an impairment charge of $184 million associated with our Northern Alberta CGU recorded at December 31, 2015 and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

DD&A decreased $56 million on a year-to-date basis. The impact of lower sales volumes and lower DD&A rates were partially offset by a $170 million impairment charge associated with our Northern Alberta CGU recorded in the first quarter of 2016.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries.

This segment also captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In the three and six months ended June 30, 2016, 17 and 24 unit trains, respectively, were loaded at Bruderheim, including one unit train for a third party.

Refinery Operations [(1)]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Crude Oil Capacity [(2)] (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**458**	441	**446**	440
Heavy Crude Oil	**228**	200	**235**	210
Light/Medium	**230**	241	**211**	230
Refined Products (Mbbls/d)	**483**	462	**472**	465
Gasoline	**240**	241	**235**	239
Distillate	**150**	148	**146**	146
Other	**93**	73	**91**	80
Crude Utilization (percent)	**100**	96	**97**	96

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30-day period.

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

Crude oil runs increased in the second quarter of 2016 compared with 2015. Higher heavy crude oil volumes were processed due to the optimization of our total crude input slate, which reduces our feedstock costs. Refined product output increased due to consistent performance of both the Wood River and Borger refineries. In the second quarter of 2015, unplanned outages at our Borger refinery resulted from process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased. Consistent performance in the current quarter was partially offset by planned and unplanned maintenance at our Wood River and Borger refineries in the first quarter of 2016. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at the Borger refinery.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**2,129**	2,437	**3,717**	4,533
Purchased Product	**1,712**	1,976	**3,140**	3,814
Gross Margin	**417**	461	**577**	719
Expenses				
Operating	**182**	160	**385**	337
(Gain) Loss on Risk Management	**42**	1	**22**	(13)
Operating Cash Flow	**193**	300	**170**	395
Capital Investment	**53**	48	**105**	92
Operating Cash Flow Net of Related Capital Investment	**140**	252	**65**	303

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil, refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through our refineries; and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the three and six months ended June 30, 2016, our gross margin declined primarily due to lower average market crack spreads as a result of higher global refined product inventory and narrowing of the Brent-WTI differential by 75 percent. This was partially offset by:

- An increase in refined product output;
- Improved margins on the sale of our secondary products, such as coke, asphalt and sulfur, due to lower overall feedstock costs consistent with the decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar relative to the U.S. dollar in the second quarter and on a year-to-date basis, compared with 2015, had a positive impact of approximately $18 million and $39 million, respectively, on our refining gross margin; and
- Widening heavy and medium crude oil differentials.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In the three and six months ended June 30, 2016, the cost of our RINs were $67 million and $129 million, respectively (2015 – $40 million and $93 million, respectively). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in the second quarter increased two percent from 2015. Higher purchased crude oil and natural gas volumes were partially offset by lower sales prices. On a year-to-date basis, revenues from third-party sales decreased eight percent compared with 2015 due to lower sales prices, partially offset by higher purchased crude oil and natural gas volumes.

Operating Expense

Primary drivers of operating expenses in the second quarter of 2016 and on a year-to-date basis were labour, maintenance and utilities. Reported operating expenses increased in the second quarter and on a year-to-date basis compared with 2015 primarily due to weakening of the Canadian dollar relative to the U.S. dollar and additional maintenance activities, partially offset by a decline in utility costs resulting from lower natural gas prices.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Wood River Refinery	**38**	34	**75**	61
Borger Refinery	**13**	13	**26**	30
Marketing	**2**	1	**4**	1
	53	48	**105**	92

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

In 2016, we expect to invest between $230 million and $280 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $5 million in the second quarter and $14 million on a year-to-date basis, primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the long-term power purchase contract and interest rate swaps. In the second quarter of 2016, our risk management activities resulted in $284 million of unrealized losses (2015 – $151 million of unrealized losses). On a year-to-date basis, we had $433 million of unrealized losses (2015 – $296 million of unrealized losses). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing and research costs.

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
General and Administrative (1)	**94**	77	**154**	148
Finance Costs	**122**	116	**246**	237
Interest Income	**(7)**	(3)	**(18)**	(14)
Foreign Exchange (Gain) Loss, Net	**20**	(100)	**(383)**	415
Research Costs	**7**	7	**25**	14
(Gain) Loss on Divestiture of Assets	**1**	-	**1**	(16)
Other (Income) Loss, Net	**2**	2	**2**	2
	239	99	**27**	786

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

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2016 were workforce, office rent and information technology costs. General and administrative expenses increased by $17 million in the second quarter and $6 million on a year-to-date basis. Savings from workforce reductions, lower information technology costs and discretionary spending were offset by severance costs of approximately $19 million recorded in the second quarter related to the workforce reductions implemented in April 2016. Additionally, a non-cash expense of $17 million ($31 million on a year-to-date basis) was recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $6 million and $9 million, respectively, in the three and six months ended June 30, 2016 as weakening of the Canadian dollar relative to the U.S. dollar increased reported interest on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the three and six months ended June 30, 2016 was 5.3 percent (2015 – 5.3 percent and 5.2 percent, respectively).

Foreign Exchange

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2016**	2015	**2016**	2015
Unrealized Foreign Exchange (Gain) Loss	**18**	(102)	**(391)**	421
Realized Foreign Exchange (Gain) Loss	**2**	2	**8**	(6)
	20	(100)	**(383)**	415

The majority of unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar, relative to the U.S. dollar, at June 30, 2016 was slightly weaker compared with March 31, 2016, resulting in unrealized losses of $18 million in the second quarter. The Canadian dollar, relative to the U.S. dollar, strengthened by six percent from December 31, 2015 to June 30, 2016 resulting in year-to-date unrealized gains of $395 million.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in the second quarter was $19 million (2015 – $21 million) and $36 million on a year-to-date basis (2015 – $42 million).

Income Tax

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2016**	2015	**2016**	2015
Current Tax				
Canada	**(30)**	321	**(57)**	235
United States	**1**	(6)	**1**	(6)
Total Current Tax Expense (Recovery)	**(29)**	315	**(56)**	229
Deferred Tax Expense (Recovery)	**(52)**	(261)	**(242)**	(288)
	(81)	54	**(298)**	(59)

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

($ millions)	Six Months Ended June 30, 2016	2015
Earnings (Loss) Before Income Tax	**(683)**	(601)
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(184)**	(157)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(23)**	4
Non-Deductible Stock-Based Compensation	**5**	5
Non-Taxable Capital (Gains) Losses	**(53)**	56
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(53)**	56
Adjustments Arising From Prior Year Tax Filings	**-**	(11)
Recognition of Capital Losses	**-**	(149)
Change in Statutory Rate	**-**	168
Other	**10**	(31)
Total Tax (Recovery)	**(298)**	(59)
Effective Tax Rate	**43.6%**	9.8%

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

In the three and six months ended June 30, 2016, we incurred losses for income tax purposes, which will be carried back to recover income taxes previously paid in Canada or recognized as a deferred tax recovery. In the second quarter of 2015, the current tax expense included an acceleration of current tax payable on prior year partnership earnings due to certain corporate restructuring transactions.

In the three and six months ended June 30, 2015, a deferred tax recovery was recorded. The recovery was largely due to the reversal of timing differences associated with the recognition of partnership income, unrealized risk management losses, the recognition of a benefit from capital losses not previously recognized and 2015 losses, partially offset by a one-time charge of approximately $168 million from the revaluation of the deferred tax liability due to the increase in the Alberta corporate tax rate. The benefit of the capital losses was recognized as a result of the agreement to dispose of the royalty interest and mineral fee title lands business.

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

Our effective tax rate differs from the statutory rate due to approximately $395 million of unrealized non-taxable foreign exchange gains.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Net Cash From (Used In)				
Operating Activities	**205**	335	**387**	610
Investing Activities	**(270)**	(424)	**(639)**	(1,067)
Net Cash Provided (Used) Before Financing Activities	**(65)**	(89)	**(252)**	(457)
Financing Activities	**(43)**	(126)	**(84)**	1,166
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**5**	1	**11**	(2)
Increase (Decrease) in Cash and Cash Equivalents	**(103)**	(214)	**(325)**	707

	June 30, 2016	December 31, 2015
Cash and Cash Equivalents	**3,780**	4,105
Committed and Undrawn Credit Facilities	**4,000**	4,000

Operating Activities

Cash from operating activities decreased for the three and six months ended June 30, 2016 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,141 million at June 30, 2016 compared with $4,337 million at December 31, 2015.

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

Investing Activities

Capital investment declined in the current quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment.

Financing Activities

Cash used in financing activities decreased in the second quarter of 2016 as we paid dividends of $0.05 per share or $42 million (2015 – $0.2662 per share or $223 million, of which $125 million was paid in cash with the remainder reinvested in common shares issued from treasury through our dividend reinvestment plan).

During the first half of 2016, we paid dividends of $0.10 per share or $83 million (2015 – $0.5324 per share or $445 million of which $263 million was paid in cash). In the first half of 2015, cash from financing activities included 67.5 million common shares issued at a price of $22.25 per share for net proceeds of $1.4 billion, which was partially offset by a net repayment of short-term borrowings.

Our long-term debt at June 30, 2016 was $6,132 million (December 31, 2015 – $6,525 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $393 million decrease in long-term debt is due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at June 30, 2016, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

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

The following sources of liquidity are available:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,780**	**Not applicable**
Committed Credit Facility	**1,000**	**April 2019**
Committed Credit Facility	**3,000**	**November 2019**
U.S. Base Shelf Prospectus [1]	**US$5,000**	**March 2018**

(1) Availability is subject to market conditions.

Committed Credit Facility

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

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

Base Shelf Prospectus

Cenovus filed a base shelf prospectus in 2016. 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 June 30, 2016, there have been no issuances 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 and asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**June 30, 2016**	December 31, 2015
Net Debt to Capitalization (1) (2)	**17%**	16%
Debt to Capitalization	**34%**	34%
Net Debt to Adjusted EBITDA (1)	**1.9x**	1.2x
Debt to Adjusted EBITDA	**4.8x**	3.1x

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

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

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

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

Share Capital and Stock-Based Compensation Plans

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 15 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at June 30, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**46,740**	**34,287**
Other Stock-Based Compensation Plans	**11,658**	**1,581**

Contractual Obligations and Commitments

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

During the first half of 2016, net transportation commitments decreased by approximately $1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth. As at June 30, 2016, total transportation commitments were $26 billion.

As at June 30, 2016, there were outstanding letters of credit aggregating $246 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

Legal Proceedings

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

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of each of our 2015 annual MD&A and first quarter 2016 MD&A. A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2015, together with updates in our first quarter 2016 MD&A and the updates provided below in this MD&A.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We continue to be exposed to the risks identified in our 2015 annual MD&A and AIF.

The following provides an update on our risks related to commodity prices, derivative financial instruments and abandonment and reclamation costs.

Commodity Price Risk

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 17 and 18 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	Three Months Ended June 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**8**	**246**	**254**	(32)	142	110
Natural Gas	**-**	**-**	**-**	(16)	15	(1)
Refining	**(1)**	**1**	**-**	2	3	5
Power [(1)]	**-**	**-**	**-**	-	(9)	(9)
Interest Rate	**-**	**37**	**37**	-	-	-
(Gain) Loss on Risk Management	**7**	**284**	**291**	(46)	151	105
Income Tax Expense (Recovery)	**(2)**	**(77)**	**(79)**	14	(45)	(31)
(Gain) Loss on Risk Management, After Tax	**5**	**207**	**212**	(32)	106	74

	Six Months Ended June 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(156)**	**364**	**208**	(160)	261	101
Natural Gas	**-**	**-**	**-**	(28)	26	(2)
Refining	**(5)**	**4**	**(1)**	(12)	12	-
Power [(1)]	**3**	**(14)**	**(11)**	3	(3)	-
Interest Rate	**-**	**79**	**79**	-	-	-
(Gain) Loss on Risk Management	**(158)**	**433**	**275**	(197)	296	99
Income Tax Expense (Recovery)	**41**	**(118)**	**(77)**	54	(82)	(28)
(Gain) Loss on Risk Management, After Tax	**(117)**	**315**	**198**	(143)	214	71

(1) The power contracts were effectively terminated on March 7, 2016. Recent litigation between third parties has caused some uncertainty regarding termination of the contracts. Any related liability or asset to Cenovus is not determinable at this time.

In the second quarter of 2016, we incurred realized losses on crude oil risk management activities, consistent with the average benchmark price exceeding our contract prices. In the first half of 2016, we recorded realized gains on crude oil risk management activities as our contract prices exceeded average benchmark prices. Unrealized losses were recorded on our crude oil financial instruments in the three and six months ended June 30, 2016 primarily due to the realization of settled positions and changes in market prices.

Unrealized losses were recorded on our interest rate hedge positions due to decreases in benchmark interest rates.

Risks Associated With Derivative Financial Instruments

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

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

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 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 to the Alberta Energy Regulator (the "AER") uneconomic oil and gas assets before starting the sales process for the insolvent party's assets. 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. The changes brought about by the Redwater decision and subsequent actions by the AER in response to Redwater could expose licenses and approval holders, including Cenovus, to increased OWA levies and impact Cenovus's ability to transfer licenses and approvals associated with any acquisition or divestiture activities.

Based on the current economic environment, 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 cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, Cenovus's business, financial condition, results of operations and cash flow. Additionally, the AER released Bulletin 2016-16 on June 20, 2016 in response to the Redwater decision, implementing important changes to the AER's procedures relating to liability management ratings, license eligibility and transfers, which may impact Cenovus's ability to transfer its licenses, approvals or permits, and which may further result in increased costs, delays and abandonment or restructuring of projects and transactions.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies during the first six months of 2016. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the six months ended June 30, 2016.

Future Accounting Pronouncements

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

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

OUTLOOK

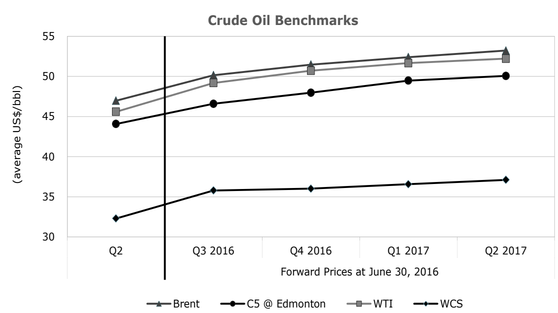
Although benchmark crude oil prices have strengthened in the second quarter of 2016, heavy oil differentials have remained relatively flat and our realized prices and netbacks remain below historical levels. Additional confidence in commodity prices, our ability to sustain cost reductions as well as fiscal and regulatory certainty are required before we will consider further expansion of existing projects or developing emerging opportunities. We will commit to project reactivation only if we believe it does not undermine the strength of our balance sheet.

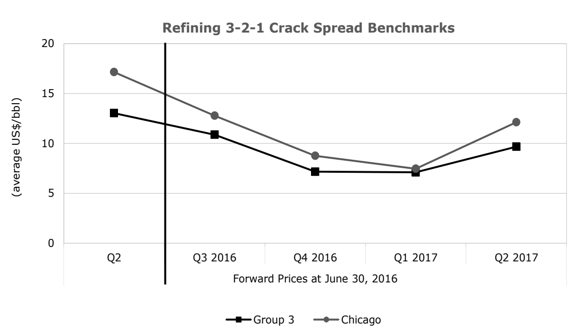
The following outlook commentary is focused on the next 12 months.

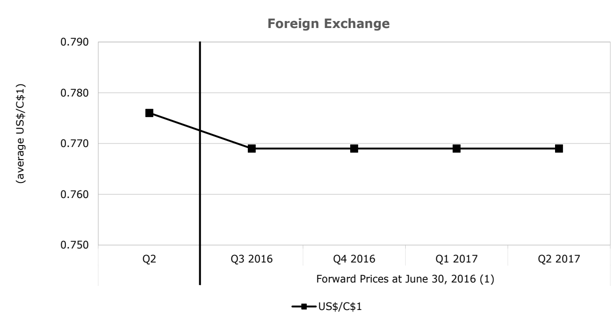
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of supply disruptions and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility and a modest price improvement in the second half of 2016. Anticipated global supply declines, combined with annual increases in demand growth, should support prices in the remainder of the year, constrained by the need to draw down surplus crude oil inventories and re-entry of Iranian crude oil supply into markets.
- We anticipate the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and
- We expect that the WTI-WCS differential will widen due to declining U.S. light tight oil supply and as a result of additional Canadian supply as production outages caused by the Alberta forest fires are brought back online.







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

U.S. refining crack spreads are expected to weaken in the second half of the year as high global refined product inventories continue to weigh on product prices while seasonal U.S. demand weakens during fall and winter periods.

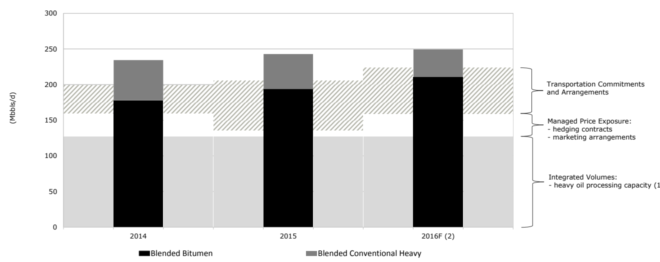
Further weakening of natural gas prices in the second quarter of 2016 reflects lower seasonal demand and record-high storage levels. Pricing is anticipated to improve throughout the second half of 2016 due to lower supply growth and stronger demand growth, although price escalation should be limited by the continued need for coal-to-gas substitution in the power sector.

We expect the Canadian dollar to continue to be tied with strengthening of crude oil prices, tempered by differing interest rate expectations between Canada and the U.S. Overall, ignoring the decline in oil price, a weaker Canadian dollar will have a positive impact on our revenues and Operating Cash Flow.

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

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

Protection Against Canadian Congestion



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

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience, while maintaining safe operations, continues to be our top priority. At June 30, 2016, we had $3.8 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. Although we have a strong balance sheet, we have undertaken additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs.

Attack Cost Structures

We will continue to focus on reducing our cost structure. We are on track to reduce our planned 2016 capital, operating, general and administrative spending by approximately $500 million, relative to our original budget released in December 2015. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

Operational Excellence

We are focused on executing our work programs safely, responsibly and efficiently through standardized processes, procedures and controls. We use a manufacturing approach to optimize value, manage risk and improve performance. We are focused on reducing the environmental impact of our operations and engaging with people and communities who may be affected by our operations in a transparent, timely and respectful way.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) (unaudited)

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

		Three Months Ended		Six Months Ended	
	Notes	**2016**	2015	**2016**	2015
Revenues	1				
Gross Sales		**3,043**	3,779	**5,308**	6,944
Less: Royalties		**36**	53	**56**	77
		3,007	3,726	**5,252**	6,867
Expenses	1				
Purchased Product		**1,624**	1,908	**2,986**	3,640
Transportation and Blending		**438**	498	**888**	1,026
Operating		**392**	426	**843**	903
Production and Mineral Taxes		**3**	6	**5**	11
(Gain) Loss on Risk Management	17	**291**	105	**275**	99
Depreciation, Depletion and Amortization	6,10	**368**	483	**910**	982
Exploration Expense	6,9	**-**	21	**1**	21
General and Administrative		**94**	77	**154**	148
Finance Costs	3	**122**	116	**246**	237
Interest Income		**(7)**	(3)	**(18)**	(14)
Foreign Exchange (Gain) Loss, Net	4	**20**	(100)	**(383)**	415
Research Costs		**7**	7	**25**	14
(Gain) Loss on Divestiture of Assets	5	**1**	-	**1**	(16)
Other (Income) Loss, Net		**2**	2	**2**	2
Earnings (Loss) Before Income Tax		**(348)**	180	**(683)**	(601)
Income Tax Expense (Recovery)	7	**(81)**	54	**(298)**	(59)
Net Earnings (Loss)		**(267)**	126	**(385)**	(542)
Net Earnings (Loss) Per Share ($)	8				
Basic and Diluted		**(0.32)**	0.15	**(0.46)**	(0.67)

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

For the periods ended June 30,
($ millions)

	Three Months Ended		Six Months Ended	
	2016	2015	**2016**	2015
Net Earnings (Loss)	**(267)**	126	**(385)**	(542)
Other Comprehensive Income (Loss), Net of Tax				
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits	**(8)**	10	**(12)**	9
Items That May be Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets	**(1)**	-	**(4)**	-
Foreign Currency Translation Adjustment	**16**	(54)	**(240)**	218
Total Other Comprehensive Income (Loss), Net of Tax	**7**	(44)	**(256)**	227
Comprehensive Income (Loss)	**(260)**	82	**(641)**	(315)

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
($ millions)

	Notes	**June 30, 2016**	December 31, 2015
Assets			
Current Assets			
Cash and Cash Equivalents		**3,780**	4,105
Accounts Receivable and Accrued Revenues		**1,419**	1,251
Income Tax Receivable		**6**	6
Inventories		**988**	810
Risk Management	17,18	**37**	301
Current Assets		**6,230**	6,473
Exploration and Evaluation Assets	1,9	**1,624**	1,575
Property, Plant and Equipment, Net	1,10	**16,518**	17,335
Income Tax Receivable		**-**	90
Other Assets		**100**	76
Goodwill	1	**242**	242
Total Assets		**24,714**	25,791
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities		**1,927**	1,702
Income Tax Payable		**125**	133
Risk Management	17,18	**103**	23
Current Liabilities		**2,155**	1,858
Long-Term Debt	11	**6,132**	6,525
Risk Management	17,18	**109**	7
Decommissioning Liabilities	12	**1,927**	2,052
Other Liabilities		**185**	142
Deferred Income Taxes		**2,529**	2,816
Total Liabilities		**13,037**	13,400
Shareholders' Equity		**11,677**	12,391
Total Liabilities and Shareholders' Equity		**24,714**	25,791

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	Total
	(Note 13)			(Note 14)	
As at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings (Loss)	-	-	(542)	-	(542)
Other Comprehensive Income (Loss)	-	-	-	227	227
Total Comprehensive Income (Loss)	-	-	(542)	227	(315)
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Stock-Based Compensation Expense	-	24	-	-	24
Dividends on Common Shares	-	-	(445)	-	(445)
As at June 30, 2015	5,534	4,315	612	634	11,095
As at December 31, 2015	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(385)	-	(385)
Other Comprehensive Income (Loss)	-	-	-	(256)	(256)
Total Comprehensive Income (Loss)	-	-	(385)	(256)	(641)
Stock-Based Compensation Expense	-	10	-	-	10
Dividends on Common Shares	-	-	(83)	-	(83)
As at June 30, 2016	**5,534**	**4,340**	**1,039**	**764**	**11,677**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the periods ended June 30,
($ millions)

	Notes	Three Months Ended 2016	Three Months Ended 2015	Six Months Ended 2016	Six Months Ended 2015
Operating Activities					
Net Earnings (Loss)		**(267)**	126	**(385)**	(542)
Depreciation, Depletion and Amortization	6,10	**368**	483	**910**	982
Exploration Expense	6,9	**-**	21	**1**	21
Deferred Income Taxes	7	**(52)**	(261)	**(242)**	(288)
Unrealized (Gain) Loss on Risk Management	17	**284**	151	**433**	296
Unrealized Foreign Exchange (Gain) Loss	4	**18**	(102)	**(391)**	421
(Gain) Loss on Divestiture of Assets	5	**1**	-	**1**	(16)
Unwinding of Discount on Decommissioning Liabilities	3,12	**32**	31	**64**	62
Other		**56**	28	**75**	36
Net Change in Other Assets and Liabilities		**(17)**	(14)	**(46)**	(68)
Net Change in Non-Cash Working Capital		**(218)**	(128)	**(33)**	(294)
Cash From Operating Activities		**205**	335	**387**	610
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	9	**(19)**	(20)	**(53)**	(94)
Capital Expenditures – Property, Plant and Equipment	10	**(225)**	(337)	**(514)**	(792)
Proceeds From Divestiture of Assets	5	**-**	-	**-**	16
Net Change in Investments and Other		**(1)**	(2)	**-**	-
Net Change in Non-Cash Working Capital		**(25)**	(65)	**(72)**	(197)
Cash From (Used in) Investing Activities		**(270)**	(424)	**(639)**	(1,067)
Net Cash Provided (Used) Before Financing Activities		**(65)**	(89)	**(252)**	(457)
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**-**	-	**-**	(19)
Common Shares Issued, Net of Issuance Costs		**-**	-	**-**	1,449
Dividends Paid on Common Shares	8	**(42)**	(125)	**(83)**	(263)
Other		**(1)**	(1)	**(1)**	(1)
Cash From (Used in) Financing Activities		**(43)**	(126)	**(84)**	1,166
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**5**	1	**11**	(2)
Increase (Decrease) in Cash and Cash Equivalents		**(103)**	(214)	**(325)**	707
Cash and Cash Equivalents, Beginning of Period		**3,883**	1,804	**4,105**	883
Cash and Cash Equivalents, End of Period		**3,780**	1,590	**3,780**	1,590

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

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

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

- **Oil Sands,** which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **Refining and Marketing,** which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory. The Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense to conform to the presentation adopted for the year ended December 31, 2015. As a result, for the three and six months ended June 30, 2015, an expense of $4 million and $3 million, respectively, were reclassified.

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

A) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**709**	891	**294**	519	**2,129**	2,437
Less: Royalties	**3**	16	**33**	37	**-**	-
	706	875	**261**	482	**2,129**	2,437
Expenses						
Purchased Product	**-**	-	**-**	-	**1,712**	1,976
Transportation and Blending	**395**	436	**45**	62	**-**	-
Operating	**104**	126	**107**	142	**182**	160
Production and Mineral Taxes	**-**	-	**3**	6	**-**	-
(Gain) Loss on Risk Management	**(24)**	(18)	**(11)**	(29)	**42**	1
Operating Cash Flow	**231**	331	**117**	301	**193**	300
Depreciation, Depletion and Amortization	**156**	158	**143**	259	**50**	45
Exploration Expense	**-**	-	**-**	21	**-**	-
Segment Income (Loss)	**75**	173	**(26)**	21	**143**	255

	Corporate and Eliminations		Consolidated	
For the three months ended June 30,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(89)**	(68)	**3,043**	3,779
Less: Royalties	**-**	-	**36**	53
	(89)	(68)	**3,007**	3,726
Expenses				
Purchased Product	**(88)**	(68)	**1,624**	1,908
Transportation and Blending	**(2)**	-	**438**	498
Operating	**(1)**	(2)	**392**	426
Production and Mineral Taxes	**-**	-	**3**	6
(Gain) Loss on Risk Management	**284**	151	**291**	105
Depreciation, Depletion and Amortization	**19**	21	**368**	483
Exploration Expense	**-**	-	**-**	21
Segment Income (Loss)	**(301)**	(170)	**(109)**	279
General and Administrative	**94**	77	**94**	77
Finance Costs	**122**	116	**122**	116
Interest Income	**(7)**	(3)	**(7)**	(3)
Foreign Exchange (Gain) Loss, Net	**20**	(100)	**20**	(100)
Research Costs	**7**	7	**7**	7
(Gain) Loss on Divestiture of Assets	**1**	-	**1**	-
Other (Income) Loss, Net	**2**	2	**2**	2
	239	99	**239**	99
Earnings (Loss) Before Income Tax			**(348)**	180
Income Tax Expense (Recovery)			**(81)**	54
Net Earnings (Loss)			**(267)**	126

B) Financial Results by Upstream Product

	Crude Oil (1)					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**707**	884	**239**	406	**946**	1,290
Less: Royalties	**3**	16	**31**	36	**34**	52
	704	868	**208**	370	**912**	1,238
Expenses						
Transportation and Blending	**395**	435	**40**	58	**435**	493
Operating	**101**	121	**70**	98	**171**	219
Production and Mineral Taxes	**-**	-	**3**	5	**3**	5
(Gain) Loss on Risk Management	**(24)**	(17)	**(11)**	(14)	**(35)**	(31)
Operating Cash Flow	**232**	329	**106**	223	**338**	552

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2**	5	**53**	111	**55**	116
Less: Royalties	**-**	-	**2**	1	**2**	1
	2	5	**51**	110	**53**	115
Expenses						
Transportation and Blending	**-**	1	**5**	4	**5**	5
Operating	**2**	4	**36**	43	**38**	47
Production and Mineral Taxes	**-**	-	**-**	1	**-**	1
(Gain) Loss on Risk Management	**-**	(1)	**-**	(15)	**-**	(16)
Operating Cash Flow	**-**	1	**10**	77	**10**	78

	Other					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**-**	2	**2**	2	**2**	4
Less: Royalties	**-**	-	**-**	-	**-**	-
	-	2	**2**	2	**2**	4
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**1**	1	**1**	1	**2**	2
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**(1)**	1	**1**	1	**-**	2

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**709**	891	**294**	519	**1,003**	1,410
Less: Royalties	**3**	16	**33**	37	**36**	53
	706	875	**261**	482	**967**	1,357
Expenses						
Transportation and Blending	**395**	436	**45**	62	**440**	498
Operating	**104**	126	**107**	142	**211**	268
Production and Mineral Taxes	**-**	-	**3**	6	**3**	6
(Gain) Loss on Risk Management	**(24)**	(18)	**(11)**	(29)	**(35)**	(47)
Operating Cash Flow	**231**	331	**117**	301	**348**	632

C) Geographic Information

	Canada		United States		Consolidated	
For the three months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1,439**	1,867	**1,604**	1,912	**3,043**	3,779
Less: Royalties	**36**	53	**-**	-	**36**	53
	1,403	1,814	**1,604**	1,912	**3,007**	3,726
Expenses						
Purchased Product	**36**	444	**1,588**	1,464	**1,624**	1,908
Transportation and Blending	**438**	498	**-**	-	**438**	498
Operating	**224**	274	**168**	152	**392**	426
Production and Mineral Taxes	**3**	6	**-**	-	**3**	6
(Gain) Loss on Risk Management	**292**	100	**(1)**	5	**291**	105
Depreciation, Depletion and Amortization	**319**	438	**49**	45	**368**	483
Exploration Expense	**-**	21	**-**	-	**-**	21
Segment Income (Loss)	**91**	33	**(200)**	246	**(109)**	279

D) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1,179**	1,623	**568**	962	**3,717**	4,533
Less: Royalties	**3**	19	**53**	58	**-**	-
	1,176	1,604	**515**	904	**3,717**	4,533
Expenses						
Purchased Product	**-**	-	**-**	-	**3,140**	3,814
Transportation and Blending	**799**	906	**92**	120	**-**	-
Operating	**231**	270	**229**	300	**385**	337
Production and Mineral Taxes	**-**	-	**5**	11	**-**	-
(Gain) Loss on Risk Management	**(130)**	(108)	**(50)**	(76)	**22**	(13)
Operating Cash Flow	**276**	536	**239**	549	**170**	395
Depreciation, Depletion and Amortization	**304**	328	**465**	521	**105**	91
Exploration Expense	**1**	-	**-**	21	**-**	-
Segment Income (Loss)	**(29)**	208	**(226)**	7	**65**	304

	Corporate and Eliminations		Consolidated	
For the six months ended June 30,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(156)**	(174)	**5,308**	6,944
Less: Royalties	**-**	-	**56**	77
	(156)	(174)	**5,252**	6,867
Expenses				
Purchased Product	**(154)**	(174)	**2,986**	3,640
Transportation and Blending	**(3)**	-	**888**	1,026
Operating	**(2)**	(4)	**843**	903
Production and Mineral Taxes	**-**	-	**5**	11
(Gain) Loss on Risk Management	**433**	296	**275**	99
Depreciation, Depletion and Amortization	**36**	42	**910**	982
Exploration Expense	**-**	-	**1**	21
Segment Income (Loss)	**(466)**	(334)	**(656)**	185
General and Administrative	**154**	148	**154**	148
Finance Costs	**246**	237	**246**	237
Interest Income	**(18)**	(14)	**(18)**	(14)
Foreign Exchange (Gain) Loss, Net	**(383)**	415	**(383)**	415
Research Costs	**25**	14	**25**	14
(Gain) Loss on Divestiture of Assets	**1**	(16)	**1**	(16)
Other (Income) Loss, Net	**2**	2	**2**	2
	27	786	**27**	786
Earnings (Loss) Before Income Tax			**(683)**	(601)
Income Tax Expense (Recovery)			**(298)**	(59)
Net Earnings (Loss)			**(385)**	(542)

E) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1,172**	1,607	**428**	721	**1,600**	2,328
Less: Royalties	**3**	19	**48**	55	**51**	74
	1,169	1,588	**380**	666	**1,549**	2,254
Expenses						
Transportation and Blending	**799**	905	**84**	111	**883**	1,016
Operating	**223**	260	**148**	208	**371**	468
Production and Mineral Taxes	**-**	-	**5**	10	**5**	10
(Gain) Loss on Risk Management	**(130)**	(106)	**(51)**	(51)	**(181)**	(157)
Operating Cash Flow	**277**	529	**194**	388	**471**	917

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**6**	11	**135**	233	**141**	244
Less: Royalties	**-**	-	**5**	3	**5**	3
	6	11	**130**	230	**136**	241
Expenses						
Transportation and Blending	**-**	1	**8**	9	**8**	10
Operating	**5**	8	**78**	90	**83**	98
Production and Mineral Taxes	**-**	-	**-**	1	**-**	1
(Gain) Loss on Risk Management	**-**	(2)	**1**	(25)	**1**	(27)
Operating Cash Flow	**1**	4	**43**	155	**44**	159

	Other					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1**	5	**5**	8	**6**	13
Less: Royalties	**-**	-	**-**	-	**-**	-
	1	5	**5**	8	**6**	13
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**3**	2	**3**	2	**6**	4
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**(2)**	3	**2**	6	**-**	9

	Total Upstream					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1,179**	1,623	**568**	962	**1,747**	2,585
Less: Royalties	**3**	19	**53**	58	**56**	77
	1,176	1,604	**515**	904	**1,691**	2,508
Expenses						
Transportation and Blending	**799**	906	**92**	120	**891**	1,026
Operating	**231**	270	**229**	300	**460**	570
Production and Mineral Taxes	**-**	-	**5**	11	**5**	11
(Gain) Loss on Risk Management	**(130)**	(108)	**(50)**	(76)	**(180)**	(184)
Operating Cash Flow	**276**	536	**239**	549	**515**	1,085

F) Geographic Information

	Canada		United States		Consolidated	
For the six months ended June 30,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,573**	3,492	**2,735**	3,452	**5,308**	6,944
Less: Royalties	**56**	77	**-**	-	**56**	77
	2,517	3,415	**2,735**	3,452	**5,252**	6,867
Expenses						
Purchased Product	**409**	876	**2,577**	2,764	**2,986**	3,640
Transportation and Blending	**888**	1,026	**-**	-	**888**	1,026
Operating	**488**	581	**355**	322	**843**	903
Production and Mineral Taxes	**5**	11	**-**	-	**5**	11
(Gain) Loss on Risk Management	**275**	99	**-**	-	**275**	99
Depreciation, Depletion and Amortization	**807**	891	**103**	91	**910**	982
Exploration Expense	**1**	21	**-**	-	**1**	21
Segment Income (Loss)	**(356)**	(90)	**(300)**	275	**(656)**	185

G) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

By Segment

	E&E [1]		PP&E [2]	
As at	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Oil Sands	**1,608**	1,560	**8,900**	8,907
Conventional	**16**	15	**3,199**	3,720
Refining and Marketing	**-**	-	**4,129**	4,398
Corporate and Eliminations	**-**	-	**290**	310
Consolidated	**1,624**	1,575	**16,518**	17,335

	Goodwill		Total Assets	
As at	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Oil Sands	**242**	242	**11,220**	11,069
Conventional	**-**	-	**3,315**	3,830
Refining and Marketing	**-**	-	**5,913**	5,844
Corporate and Eliminations	**-**	-	**4,266**	5,048
Consolidated	**242**	242	**24,714**	25,791

(1) *Exploration and Evaluation ("E&E") assets.*
(2) *Property, Plant and Equipment ("PP&E").*

By Geographic Region

	E&E		PP&E	
As at	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Canada	**1,624**	1,575	**12,482**	13,028
United States	**-**	-	**4,036**	4,307
Consolidated	**1,624**	1,575	**16,518**	17,335

	Goodwill		Total Assets	
As at	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Canada	**242**	242	**19,272**	20,627
United States	**-**	-	**5,442**	5,164
Consolidated	**242**	242	**24,714**	25,791

H) Capital Expenditures [(1)]

	Three Months Ended		Six Months Ended	
For the periods ended June 30,	**2016**	2015	**2016**	2015
Capital				
Oil Sands	**139**	260	**366**	674
Conventional	**34**	36	**73**	102
Refining and Marketing	**53**	48	**105**	92
Corporate	**10**	13	**15**	18
	236	357	**559**	886
Acquisition Capital				
Oil Sands	**11**	-	**11**	-
	247	357	**570**	886

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

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2015, except for income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2015, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective July 27, 2016.

3. FINANCE COSTS

	Three Months Ended		Six Months Ended	
For the periods ended June 30,	**2016**	2015	**2016**	2015
Interest Expense – Short-Term Borrowings and Long-Term Debt	**83**	79	**171**	159
Unwinding of Discount on Decommissioning Liabilities (Note 12)	**32**	31	**64**	62
Other	**7**	6	**11**	16
	122	116	**246**	237

4. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Six Months Ended	
For the periods ended June 30,	**2016**	2015	**2016**	2015
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	**18**	(99)	**(395)**	415
Other	**-**	(3)	**4**	6
Unrealized Foreign Exchange (Gain) Loss	**18**	(102)	**(391)**	421
Realized Foreign Exchange (Gain) Loss	**2**	2	**8**	(6)
	20	(100)	**(383)**	415

5. DIVESTITURES

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

6. IMPAIRMENTS

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

As at June 30, 2016, there were no indicators of impairment.

2016 Impairments

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

The recoverable amount was determined using fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with Cenovus's independent qualified reserves evaluators (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at March 31, 2016, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.3 billion.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no impairments of goodwill for the six months ended June 30, 2016.

Key Assumptions

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

Crude Oil and Natural Gas Prices

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

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

(1) West Texas Intermediate ("WTI") crude oil.
(2) Western Canadian Select ("WCS") crude oil blend.
(3) Alberta Energy Company ("AECO") natural gas.
(4) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.

Discount and Inflation Rates

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

Sensitivities

As at March 31, 2016, changes to the assumed discount rate or forward price estimates over the life of the reserves independently would have the following impact on the 2016 impairment of the Northern Alberta CGU:

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

2015 Impairments

There were no CGU or goodwill impairments for the six months ended June 30, 2015.

B) Asset Impairments

There were no asset impairments for the six months ended June 30, 2016.

For the six months ended June 30, 2015, $21 million of previously capitalized E&E costs related to exploration assets within the Saskatchewan CGU were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense in the Conventional segment.

7. INCOME TAXES

The provision for income taxes is:

	Three Months Ended		Six Months Ended	
For the periods ended June 30,	**2016**	2015	**2016**	2015
Current Tax				
Canada	**(30)**	321	**(57)**	235
United States	**1**	(6)	**1**	(6)
Total Current Tax Expense (Recovery)	**(29)**	315	**(56)**	229
Deferred Tax Expense (Recovery)	**(52)**	(261)	**(242)**	(288)
	(81)	54	**(298)**	(59)

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

	Six Months Ended	
For the periods ended June 30,	**2016**	2015
Earnings (Loss) Before Income Tax	**(683)**	(601)
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(184)**	(157)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(23)**	4
Non-Deductible Stock-Based Compensation	**5**	5
Non-Taxable Capital (Gains) Losses	**(53)**	56
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(53)**	56
Adjustments Arising From Prior Year Tax Filings	**-**	(11)
Recognition of Capital Losses	**-**	(149)
Change in Statutory Rate	**-**	168
Other	**10**	(31)
Total Tax (Recovery)	**(298)**	(59)
Effective Tax Rate	**43.6%**	9.8%

8. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share

For the periods ended June 30,	Three Months Ended 2016	2015	Six Months Ended 2016	2015
Net Earnings (Loss) – Basic and Diluted ($ millions)	**(267)**	126	**(385)**	(542)
Weighted Average Number of Shares – Basic and Diluted (millions)	**833.3**	828.6	**833.3**	803.9
Net Earnings (Loss) Per Share – Basic and Diluted ($)	**(0.32)**	0.15	**(0.46)**	(0.67)

B) Dividends Per Share

For the six months ended June 30, 2016, the Company paid dividends of $83 million or $0.10 per share, all of which was paid in cash (six months ended June 30, 2015 – $445 million or $0.5324 per share, including cash dividends of $263 million).

9. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2015	1,575
Additions	53
Exploration Expense	(1)
Change in Decommissioning Liabilities	(3)
As at June 30, 2016	**1,624**

10. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets: Development & Production	Upstream Assets: Other Upstream	Refining Equipment	Other (1)	Total
COST					
As at December 31, 2015	31,481	331	5,206	1,037	38,055
Additions	398	-	100	19	517
Change in Decommissioning Liabilities	(144)	-	(11)	(1)	(156)
Exchange Rate Movements and Other	(16)	-	(313)	1	(328)
As at June 30, 2016	**31,719**	**331**	**4,982**	**1,056**	**38,088**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2015	18,908	277	896	639	20,720
Depreciation, Depletion and Amortization	580	19	103	34	736
Impairment Losses (Note 6)	170	-	-	4	174
Exchange Rate Movements and Other	(3)	-	(57)	-	(60)
As at June 30, 2016	**19,655**	**296**	**942**	**677**	**21,570**
CARRYING VALUE					
As at December 31, 2015	12,573	54	4,310	398	17,335
As at June 30, 2016	**12,064**	**35**	**4,040**	**379**	**16,518**

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

11. LONG-TERM DEBT

As at	US$ Principal	June 30, 2016	December 31, 2015
Revolving Term Debt [1]	-	-	-
U.S. Dollar Denominated Unsecured Notes	4,750	6,179	6,574
Total Debt Principal		6,179	6,574
Debt Discounts and Transaction Costs		(47)	(49)
		6,132	6,525

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

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows the Company to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018 and replaced the Company's US$2.0 billion base debt shelf prospectus. In addition, the Company had a $1.5 billion Canadian base debt shelf prospectus that expired on July 25, 2016. As at June 30, 2016, there have been no securities issued under the US$5.0 billion base shelf prospectus.

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

As at June 30, 2016, the Company is in compliance with all of the terms of its debt agreements.

12. DECOMMISSIONING LIABILITIES

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

	Total
As at December 31, 2015	2,052
Liabilities Incurred	3
Liabilities Settled	(29)
Change in Estimated Future Cash Flows	(1)
Change in Discount Rate	(161)
Unwinding of Discount on Decommissioning Liabilities	64
Foreign Currency Translation	(1)
As at June 30, 2016	1,927

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 7.0 percent as at June 30, 2016 (December 31, 2015 – 6.4 percent).

13. SHARE CAPITAL

A) Authorized

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

B) Issued and Outstanding

	June 30, 2016	
As at	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year and End of Period	**833,290**	**5,534**

There were no preferred shares outstanding as at June 30, 2016 (December 31, 2015 – nil).

As at June 30, 2016, there were 11 million (December 31, 2015 – 12 million) common shares available for future issuance under the stock option plan.

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	**Foreign Currency Translation**	**Available for Sale Financial Assets**	**Total**
As at December 31, 2015	**(10)**	**1,014**	**16**	**1,020**
Other Comprehensive Income (Loss), Before Tax	**(17)**	**(240)**	**(5)**	**(262)**
Income Tax	**5**	**-**	**1**	**6**
As at June 30, 2016	**(22)**	**774**	**12**	**764**

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at December 31, 2014	(30)	427	10	407
Other Comprehensive Income (Loss), Before Tax	11	218	-	229
Income Tax	(2)	-	-	(2)
As at June 30, 2015	(21)	645	10	634

15. STOCK-BASED COMPENSATION PLANS

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

As at June 30, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
NSRs	**43,261**	**30,808**
TSARs	**3,479**	**3,479**
PSUs	**6,234**	**-**
RSUs	**3,843**	**-**
DSUs	**1,581**	**1,581**

For the six months ended June 30, 2016	**Units Granted** (thousands)	**Units Vested and Paid Out** (thousands)
NSRs	**3,595**	**-**
PSUs	**2,308**	**979**
RSUs	**1,682**	**32**
DSUs	**90**	**5**

The weighted average exercise price of NSRs and TSARs as at June 30, 2016 was $30.61 and $26.67, respectively.

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

	Three Months Ended		**Six Months Ended**	
For the periods ended June 30,	**2016**	2015	**2016**	2015
NSRs	**4**	3	**8**	14
TSARs	**-**	-	**-**	(3)
PSUs	**8**	9	**-**	(7)
RSUs	**2**	-	**5**	3
DSUs	**3**	(1)	**2**	(3)
Stock-Based Compensation Expense	**17**	11	**15**	4
Stock-Based Compensation Costs Capitalized	**5**	5	**4**	2
Total Stock-Based Compensation	**22**	16	**19**	6

16. CAPITAL STRUCTURE

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

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

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

A) Debt to Capitalization and Net Debt to Capitalization

As at	**June 30, 2016**	December 31, 2015
Debt	**6,132**	6,525
Add (Deduct):		
Cash and Cash Equivalents	**(3,780)**	(4,105)
Net Debt	**2,352**	2,420
Debt	**6,132**	6,525
Shareholders' Equity	**11,677**	12,391
	17,809	18,916
Debt to Capitalization	**34%**	34%
Net Debt	**2,352**	2,420
Shareholders' Equity	**11,677**	12,391
	14,029	14,811
Net Debt to Capitalization	**17%**	16%

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

As at	**June 30, 2016**	December 31, 2015
Debt	**6,132**	6,525
Net Debt	**2,352**	2,420
Net Earnings	**775**	618
Add (Deduct):		
Finance Costs	**491**	482
Interest Income	**(32)**	(28)
Income Tax Expense (Recovery)	**(320)**	(81)
Depreciation, Depletion and Amortization	**2,042**	2,114
E&E Impairment	**118**	138
Unrealized (Gain) Loss on Risk Management	**332**	195
Foreign Exchange (Gain) Loss, Net	**238**	1,036
(Gain) Loss on Divestitures of Assets	**(2,375)**	(2,392)
Other (Income) Loss, Net	**2**	2
Adjusted EBITDA (1)	**1,271**	2,084
Debt to Adjusted EBITDA	**4.8x**	3.1x
Net Debt to Adjusted EBITDA	**1.9x**	1.2x

(1) *Calculated on a trailing twelve-month basis.*

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

Effective April 22, 2016, the Company extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at June 30, 2016, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus has in place a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

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

As at June 30, 2016, Cenovus is in compliance with all of the terms of its debt agreements.

17. FINANCIAL INSTRUMENTS

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

A) Fair Value of Non-Derivative Financial Instruments

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

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

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at June 30, 2016, the carrying value of Cenovus's long-term debt was $6,132 million and the fair value was $6,024 million (December 31, 2015 carrying value – $6,525 million, fair value – $6,050 million).

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

	Total
As at December 31, 2015	**42**
Change in Fair Value [1]	**(5)**
As at June 30, 2016	**37**

(1) Unrealized gains and losses on available for sale financial assets are recorded in other comprehensive income.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, power purchase contracts, and interest rate swaps. Crude oil, condensate and, if entered, natural gas contracts, are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including quoted market prices and interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	June 30, 2016			December 31, 2015		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**37**	**132**	**(95)**	301	15	286
Power [1]	**-**	**-**	**-**	-	13	(13)
	37	**132**	**(95)**	301	28	273
Interest Rate	**-**	**80**	**(80)**	-	2	(2)
Total Fair Value	**37**	**212**	**(175)**	301	30	271

(1) The power contracts were effectively terminated on March 7, 2016. Recent litigation between third parties has caused some uncertainty regarding termination of the contracts. Any related liability or asset to Cenovus is not determinable at this time.

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

As at	**June 30, 2016**	December 31, 2015
Prices Sourced From Observable Data or Market Corroboration (Level 2)	**(175)**	284
Prices Determined From Unobservable Inputs (Level 3)	**-**	(13)
	(175)	271

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

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

	2016	2015
Fair Value of Contracts, Beginning of Year	**271**	462
Fair Value of Contracts Realized During the Period [(1)]	**(158)**	(197)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Period [(2)]	**(275)**	(99)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(13)**	1
Fair Value of Contracts, End of Period	**(175)**	167

(1) Includes a realized loss of $3 million related to power contracts (2015 – $3 million loss).
(2) Includes an increase of $10 million related to power contracts (2015 – $1 million increase).

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

	Three Months Ended		**Six Months Ended**	
For the periods ended June 30,	**2016**	2015	**2016**	2015
Realized (Gain) Loss [(1)]	**7**	(46)	**(158)**	(197)
Unrealized (Gain) Loss [(2)]	**284**	151	**433**	296
(Gain) Loss on Risk Management	**291**	105	**275**	99

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

18. RISK MANAGEMENT

The Company is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk. A description of the nature and extent of risks arising from the Company's financial assets and liabilities can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2015. The Company's exposure to these risks has not changed significantly since December 31, 2015. To manage the Company's exposure to interest rate volatility, the Company has entered into interest rate swap contracts related to future debt issuances. As at June 30, 2016, the Company had a notional amount of US$400 million in interest rate swaps.

Net Fair Value of Risk Management Positions

As at June 30, 2016	Notional Volumes	Terms	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	10,000 bbls/d	January – December 2016	US$66.93/bbl	**39**
Brent Fixed Price	5,000 bbls/d	July – December 2016	$75.46/bbl	**9**
Brent Fixed Price	10,000 bbls/d	July – December 2017	US$53.09/bbl	**(3)**
Brent Fixed Price	10,000 bbls/d	January – June 2018	US$54.06/bbl	**(3)**
WTI Fixed Price	10,000 bbls/d	July – December 2016	US$39.02/bbl	**(26)**
WTI Fixed Price	70,000 bbls/d	January – June 2017	US$46.35/bbl	**(92)**
WCS Differential (1)	31,600 bbls/d	January – December 2016	US$(13.96)/bbl	**3**
Brent Collars	10,000 bbls/d	July – December 2016	US$45.55 – US$56.55/bbl	**-**
WTI Collars	30,000 bbls/d	July – December 2016	US$45.39 – US$55.36/bbl	**1**
WTI Collars	30,000 bbls/d	July – December 2017	US$43.92 – US$53.96/bbl	**(24)**
Other Financial Positions (2)				**(1)**
Crude Oil Fair Value Position				**(97)**
Condensate Purchase Contracts				
Mont Belvieu Fixed Price	3,000 bbls/d	January – December 2016	US$39.20/bbl	**2**
Interest Rate Swaps				**(80)**

(1) Cenovus entered into fixed-price swaps and futures to protect against widening light/heavy price differentials for heavy crudes.
(2) Other financial positions are part of ongoing operations to market the Company's production.

Sensitivities – Risk Management Positions

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

Risk Management Positions in Place as at June 30, 2016

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent and WTI Hedges	**(408)**	**407**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	**36**	**(36)**
Condensate Commodity Price	± US$10 per bbl Applied to Condensate Hedges	**12**	**(12)**
Interest Rate Swaps	± 50 Basis Points	**54**	**(64)**

19. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, the Company has commitments related to its risk management program and an obligation to fund its defined benefit pension and other post-employment benefit plans. Additional information related to the Company's commitments can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

During the six months ended June 30, 2016, the Company's transportation commitments decreased approximately $1 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement. As at June 30, 2016, total transportation commitments were $26 billion.

As at June 30, 2016, there were outstanding letters of credit aggregating $246 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

B) Legal Proceedings

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)

Revenues

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Gross Sales									
Upstream	1,747	1,003	744	4,739	1,002	1,152	2,585	1,410	1,175
Refining and Marketing	3,717	2,129	1,588	8,805	2,030	2,242	4,533	2,437	2,096
Corporate and Eliminations	(156)	(89)	(67)	(337)	(77)	(86)	(174)	(68)	(106)
Less: Royalties	56	36	20	143	31	35	77	53	24
Revenues	5,252	3,007	2,245	13,064	2,924	3,273	6,867	3,726	3,141

Operating Cash Flow

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Crude Oil and Natural Gas Liquids									
Foster Creek	109	98	11	454	72	168	214	130	84
Christina Lake	168	134	34	592	118	159	315	199	116
Conventional	194	106	88	683	132	163	388	223	165
Natural Gas	44	10	34	307	69	79	159	78	81
Other Upstream Operations	-	-	-	18	6	3	9	2	7
	515	348	167	2,054	397	572	1,085	632	453
Refining and Marketing	170	193	(23)	385	(40)	30	395	300	95
Operating Cash Flow [1]	685	541	144	2,439	357	602	1,480	932	548

Cash Flow

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Cash from Operating Activities	387	205	182	1,474	322	542	610	335	275
Deduct (Add Back):									
Net Change in Other Assets and Liabilities	(46)	(17)	(29)	(107)	(26)	(13)	(68)	(14)	(54)
Net Change in Non-Cash Working Capital	(33)	(218)	185	(110)	73	111	(294)	(128)	(166)
Cash Flow [2]	466	440	26	1,691	275	444	972	477	495
Per Share - Basic	0.56	0.53	0.03	2.07	0.33	0.53	1.21	0.58	0.64
- Diluted	0.56	0.53	0.03	2.07	0.33	0.53	1.21	0.58	0.64

Earnings

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Operating Earnings (Loss) [3]	(462)	(39)	(423)	(403)	(438)	(28)	63	151	(88)
Per Share - Diluted	(0.55)	(0.05)	(0.51)	(0.49)	(0.53)	(0.03)	0.08	0.18	(0.11)
Net Earnings (Loss)	(385)	(267)	(118)	618	(641)	1,801	(542)	126	(668)
Per Share - Basic	(0.46)	(0.32)	(0.14)	0.75	(0.77)	2.16	(0.67)	0.15	(0.86)
- Diluted	(0.46)	(0.32)	(0.14)	0.75	(0.77)	2.16	(0.67)	0.15	(0.86)

Tax & Exchange Rates

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Effective Tax Rates Using:									
Net Earnings [4]	43.6%			(15.1)%					
Operating Earnings, Excluding Divestitures	28.3%			32.4%					
Canadian Statutory Rate [5]	27.0%			26.1%					
U.S. Statutory Rate	38.0%			38.0%					
Foreign Exchange Rates *(US$ per C$1)*									
Average	0.752	0.776	0.728	0.782	0.749	0.764	0.810	0.813	0.806
Period End	0.769	0.769	0.771	0.723	0.723	0.747	0.802	0.802	0.789

(1) Operating Cash Flow is a non-GAAP measure defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

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

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

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

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

Financial Metrics (Non-GAAP measures)

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Net Debt to Capitalization [1] [2]	17%	17%	16%	16%	16%	13%	28%	28%	27%
Debt to Capitalization [3] [4]	34%	34%	34%	34%	34%	33%	35%	35%	35%
Net Debt to Adjusted EBITDA [1] [5]	1.9x	1.9x	1.3x	1.2x	1.2x	0.8x	1.5x	1.5x	1.3x
Debt to Adjusted EBITDA [3] [5]	4.8x	4.8x	3.6x	3.1x	3.1x	2.7x	2.1x	2.1x	1.9x
Return on Capital Employed [6]	6%	6%	8%	5%	5%	6%	(3)%	(3)%	0%
Return on Common Equity [7]	7%	7%	10%	5%	5%	7%	(6)%	(6)%	(2)%

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

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

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

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

(5) Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis.

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

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Common Share Information	2016 Year to Date	2016 Q2	2016 Q1	2015 Year	2015 Q4	2015 Q3	2015 Q2 Year to Date	2015 Q2	2015 Q1
Common Shares Outstanding *(millions)*									
Period End	**833.3**	**833.3**	833.3	833.3	833.3	833.3	**833.3**	833.3	828.5
Average - Basic	**833.3**	**833.3**	833.3	818.7	833.3	833.3	**803.9**	828.6	778.9
Average - Diluted	**833.3**	**833.3**	833.3	818.7	833.3	833.3	**803.9**	828.6	778.9
Price Range *($ per share)*									
TSX - C$									
High	**21.00**	**21.00**	18.15	26.42	22.35	20.91	**26.42**	24.28	26.42
Low	**12.70**	**16.12**	12.70	15.75	16.85	15.75	**19.53**	19.53	20.45
Close	**17.87**	**17.87**	16.90	17.50	17.50	20.24	**19.98**	19.98	21.35
NYSE - US$									
High	**16.56**	**16.56**	13.97	21.12	17.23	15.97	**21.12**	19.72	21.12
Low	**9.10**	**12.25**	9.10	11.85	12.10	11.85	**15.69**	15.69	16.29
Close	**13.82**	**13.82**	13.00	12.62	12.62	15.16	**16.01**	16.01	16.88
Dividends *($ per share)*	**0.1000**	**0.0500**	0.0500	0.8524	0.1600	0.1600	**0.5324**	0.2662	0.2662
Share Volume Traded *(millions)*	**856.1**	**373.3**	482.8	1,691.2	377.1	483.3	**830.9**	388.7	442.1

Net Capital Investment	2016 Year to Date	2016 Q2	2016 Q1	2015 Year	2015 Q4	2015 Q3	2015 Q2 Year to Date	2015 Q2	2015 Q1
Capital Investment *($ millions)*									
Oil Sands									
Foster Creek	**157**	**68**	89	403	85	96	**222**	73	149
Christina Lake	**175**	**61**	114	647	132	147	**368**	161	207
Total	**332**	**129**	203	1,050	217	243	**590**	234	356
Other Oil Sands	**34**	**10**	24	135	22	29	**84**	26	58
	366	**139**	227	1,185	239	272	**674**	260	414
Conventional	**73**	**34**	39	244	87	55	**102**	36	66
Refining and Marketing	**105**	**53**	52	248	89	67	**92**	48	44
Corporate	**15**	**10**	5	37	13	6	**18**	13	5
Capital Investment	**559**	**236**	323	1,714	428	400	**886**	357	529
Acquisitions	**11**	**11**	-	87	3	84	**-**	-	-
Divestitures	**-**	**-**	-	(3,344)	1	(3,329)	**(16)**	-	(16)
Net Acquisition and Divestiture Activity	**11**	**11**	-	(3,257)	4	(3,245)	**(16)**	-	(16)
Net Capital Investment	**570**	**247**	323	(1,543)	432	(2,845)	**870**	357	513

Operating Statistics - Before Royalties

Upstream Production Volumes	2016 Year to Date	2016 Q2	2016 Q1	2015 Year	2015 Q4	2015 Q3	2015 Q2 Year to Date	2015 Q2	2015 Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*									
Oil Sands									
Foster Creek	**62,713**	**64,544**	60,882	65,345	63,680	71,414	**63,106**	58,363	67,901
Christina Lake	**77,577**	**78,060**	77,093	74,975	75,733	75,329	**74,410**	72,371	76,471
	140,290	**142,604**	137,975	140,320	139,413	146,743	**137,516**	130,734	144,372
Conventional									
Heavy Oil	**29,873**	**28,500**	31,247	34,888	32,363	33,997	**36,624**	36,099	37,155
Light and Medium Oil	**26,649**	**26,177**	27,121	30,486	26,625	28,491	**33,463**	31,809	35,135
Natural Gas Liquids [(1)]	**1,003**	**799**	1,208	1,253	1,155	1,191	**1,335**	1,312	1,358
	57,525	**55,476**	59,576	66,627	60,143	63,679	**71,422**	69,220	73,648
Total Crude Oil and Natural Gas Liquids	**197,815**	**198,080**	197,551	206,947	199,556	210,422	**208,938**	199,954	218,020
Natural Gas *(MMcf/d)*									
Oil Sands	**17**	**18**	17	19	19	19	**20**	21	20
Conventional	**386**	**381**	391	422	405	411	**436**	429	442
Total Natural Gas	**403**	**399**	408	441	424	430	**456**	450	462
Total Production *(BOE/d)*	**264,982**	**264,580**	265,551	280,447	270,223	282,089	**284,938**	274,954	295,020

(1) Natural gas liquids include condensate volumes.

Average Royalty Rates *(Excluding Impact of Realized Gain (Loss) on Risk Management)*	2016 Year to Date	2016 Q2	2016 Q1	2015 Year	2015 Q4	2015 Q3	2015 Q2 Year to Date	2015 Q2	2015 Q1
Oil Sands									
Foster Creek [(1)]	**0.3%**	**1.0%**	(4.9)%	1.9%	0.7%	0.8%	**2.8%**	5.0%	(1.2)%
Christina Lake	**1.2%**	**1.2%**	1.2%	2.8%	1.9%	3.7%	**2.7%**	2.5%	3.1%
Conventional									
Pelican Lake	**12.1%**	**14.3%**	8.3%	9.0%	8.1%	4.7%	**10.9%**	14.3%	6.0%
Weyburn	**20.8%**	**23.9%**	16.6%	17.7%	17.0%	18.7%	**17.6%**	18.4%	16.5%
Other	**10.0%**	**8.6%**	12.0%	5.2%	12.2%	8.2%	**2.2%**	1.2%	3.5%
Natural Gas Liquids	**15.6%**	**15.0%**	16.1%	5.6%	12.8%	7.1%	**2.2%**	2.2%	2.3%
Natural Gas	**4.1%**	**3.7%**	4.3%	2.5%	3.8%	3.7%	**1.4%**	1.2%	1.6%

(1) In Q1 2015, regulatory approval was received to include certain capital costs incurred in previous years in the royalty calculation which has resulted in a negative rate. Excluding the credit, the Q1 2015 and year-to-date royalty rate would have been 5.9 percent and 5.0 percent, respectively.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Refining	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Refinery Operations [1]									
Crude Oil Capacity *(Mbbls/d)*	460	460	460	460	460	460	460	460	460
Crude Oil Runs *(Mbbls/d)*	446	458	435	419	405	394	440	441	439
Heavy Oil	235	228	241	200	196	186	210	200	220
Light/Medium	211	230	194	219	209	208	230	241	219
Crude Utilization	97%	100%	95%	91%	88%	86%	96%	96%	95%
Refined Products *(Mbbls/d)*	472	483	460	444	430	414	465	462	469

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

Selected Average Benchmark Prices	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
Brent	41.03	46.97	35.08	53.64	44.71	51.17	59.33	63.50	55.17
West Texas Intermediate ("WTI")	39.52	45.59	33.45	48.80	42.18	46.43	53.29	57.94	48.63
Differential Brent - WTI	1.51	1.38	1.63	4.84	2.53	4.74	6.04	5.56	6.54
Western Canadian Select ("WCS")	25.75	32.29	19.21	35.28	27.69	33.16	40.13	46.35	33.90
Differential WTI - WCS	13.77	13.30	14.24	13.52	14.49	13.27	13.16	11.59	14.73
Condensate (C5 @ Edmonton)	39.23	44.07	34.39	47.36	41.67	44.21	51.78	57.94	45.62
Differential WTI - Condensate (Premium)/Discount	0.29	1.52	(0.94)	1.44	0.51	2.22	1.51	-	3.01
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*									
Chicago	13.36	17.15	9.58	19.11	14.47	24.67	18.65	20.77	16.53
Group 3	11.78	13.03	10.52	18.16	13.82	22.03	18.40	19.34	17.46
Natural Gas Prices									
AECO *(C$/Mcf)*	1.68	1.25	2.11	2.77	2.65	2.80	2.81	2.67	2.95
NYMEX *(US$/Mcf)*	2.02	1.95	2.09	2.66	2.27	2.77	2.81	2.64	2.98
Differential NYMEX - AECO *(US$/Mcf)*	0.78	0.99	0.56	0.49	0.27	0.61	0.53	0.50	0.57

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

Per-unit Results

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

	2016			2015					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Heavy Oil - Foster Creek [1] [2] *($/bbl)*									
Price	22.78	33.40	11.82	33.65	25.09	33.35	38.53	48.25	29.42
Royalties	0.04	0.23	(0.16)	0.47	0.12	0.20	0.82	1.97	(0.25)
Transportation and Blending	10.09	11.44	8.70	8.84	8.53	8.50	9.22	9.04	9.39
Operating	11.09	10.15	12.05	12.60	11.66	11.27	13.91	13.29	14.50
Netback	1.56	11.58	(8.77)	11.74	4.78	13.38	14.58	23.95	5.78
Heavy Oil - Christina Lake [1] [2] *($/bbl)*									
Price	18.33	28.31	8.85	28.45	21.34	27.46	32.71	43.36	23.30
Royalties	0.16	0.28	0.05	0.67	0.30	0.83	0.79	0.99	0.61
Transportation and Blending	5.10	4.90	5.28	4.72	5.40	5.00	4.22	4.29	4.17
Operating	7.00	6.35	7.61	8.01	7.80	7.80	8.22	8.20	8.24
Netback	6.07	16.78	(4.09)	15.05	7.84	13.83	19.48	29.88	10.28
Total Heavy Oil - Oil Sands [1] [2] *($/bbl)*									
Price	20.28	30.59	10.13	30.88	23.08	30.35	35.35	45.61	26.04
Royalties	0.11	0.26	(0.04)	0.58	0.22	0.52	0.80	1.44	0.22
Transportation and Blending	7.29	7.84	6.75	6.64	6.85	6.72	6.49	6.48	6.50
Operating	8.79	8.06	9.52	10.13	9.59	9.46	10.79	10.57	10.99
Netback	4.09	14.43	(6.10)	13.53	6.42	13.65	17.27	27.12	8.33
Heavy Oil - Conventional [1] [2] *($/bbl)*									
Price	31.15	36.77	25.99	39.95	32.84	37.09	44.24	52.63	35.85
Royalties	2.62	3.95	1.40	2.97	2.24	1.73	3.84	5.34	2.34
Transportation and Blending	4.33	3.85	4.77	3.36	3.63	3.36	3.25	3.09	3.42
Operating	13.19	12.34	13.98	15.92	15.20	15.59	16.37	15.45	17.30
Production and Mineral Taxes	-	0.01	-	0.04	(0.03)	0.07	0.05	0.08	0.02
Netback	11.01	16.62	5.84	17.66	11.80	16.34	20.73	28.67	12.77
Total Heavy Oil [1] [2] *($/bbl)*									
Price	22.18	31.64	12.98	32.73	24.87	31.63	37.34	47.24	28.15
Royalties	0.55	0.89	0.22	1.07	0.59	0.75	1.48	2.35	0.68
Transportation and Blending	6.77	7.16	6.39	5.97	6.26	6.08	5.77	5.69	5.83
Operating	9.56	8.79	10.32	11.31	10.62	10.62	12.04	11.70	12.35
Production and Mineral Taxes	-	-	-	0.01	(0.01)	0.01	0.01	0.02	-
Netback	5.30	14.80	(3.95)	14.37	7.41	14.17	18.04	27.48	9.29

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

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

Cost of Condensate per Barrel of Unblended Crude Oil *($/bbl)*									
Foster Creek	25.44	24.76	26.13	27.44	25.96	24.20	30.21	29.82	30.57
Christina Lake	26.35	26.24	26.45	29.50	27.39	26.42	32.21	32.90	31.60
Heavy Oil - Oil Sands	25.95	25.58	26.31	28.54	26.72	25.33	31.30	31.48	31.14
Heavy Oil - Conventional	10.19	10.34	10.04	10.94	9.99	9.56	11.96	12.42	11.50
Total Heavy Oil	23.19	22.99	23.39	24.94	23.64	22.34	26.98	27.06	26.91

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

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

	2016			2015					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Light and Medium Oil *($/bbl)*									
Price	**41.12**	**48.09**	34.36	50.64	45.35	49.57	**53.24**	61.66	45.81
Royalties	**6.82**	**8.52**	5.18	5.66	6.97	7.02	**4.55**	5.67	3.56
Transportation and Blending	**2.75**	**2.77**	2.73	2.91	2.80	2.88	**2.97**	3.06	2.88
Operating	**16.28**	**16.21**	16.34	16.27	17.37	15.92	**15.98**	15.90	16.04
Production and Mineral Taxes	**1.00**	**1.18**	0.82	1.41	0.76	1.60	**1.59**	1.95	1.28
Netback	**14.27**	**19.41**	9.29	24.39	17.45	22.15	**28.15**	35.08	22.05
Total Crude Oil [(1)] *($/bbl)*									
Price	**24.78**	**33.89**	15.91	35.41	27.62	34.08	**39.93**	49.55	31.09
Royalties	**1.41**	**1.93**	0.90	1.75	1.44	1.60	**1.98**	2.88	1.16
Transportation and Blending	**6.22**	**6.56**	5.89	5.51	5.79	5.64	**5.31**	5.27	5.34
Operating	**10.48**	**9.80**	11.14	12.05	11.52	11.35	**12.68**	12.37	12.97
Production and Mineral Taxes	**0.14**	**0.16**	0.11	0.22	0.10	0.23	**0.27**	0.33	0.22
Netback	**6.53**	**15.44**	(2.13)	15.88	8.77	15.26	**19.69**	28.70	11.40
Natural Gas Liquids *($/bbl)*									
Price	**26.23**	**28.11**	24.99	30.98	30.70	24.57	**34.01**	39.64	28.51
Royalties	**4.10**	**4.20**	4.03	1.74	3.94	1.75	**0.76**	0.87	0.66
Netback	**22.13**	**23.91**	20.96	29.24	26.76	22.82	**33.25**	38.77	27.85
Total Liquids [(1)] *($/bbl)*									
Price	**24.79**	**33.87**	15.97	35.38	27.63	34.03	**39.90**	49.48	31.08
Royalties	**1.42**	**1.94**	0.92	1.75	1.46	1.60	**1.97**	2.86	1.16
Transportation and Blending	**6.19**	**6.53**	5.85	5.48	5.76	5.61	**5.27**	5.24	5.31
Operating	**10.43**	**9.76**	11.08	11.98	11.46	11.28	**12.60**	12.29	12.89
Production and Mineral Taxes	**0.14**	**0.16**	0.11	0.22	0.10	0.23	**0.27**	0.33	0.22
Netback	**6.61**	**15.48**	(1.99)	15.95	8.85	15.31	**19.79**	28.76	11.50
Total Natural Gas *($/Mcf)*									
Price	**1.92**	**1.53**	2.31	2.92	2.78	3.00	**2.94**	2.82	3.05
Royalties	**0.07**	**0.04**	0.09	0.07	0.10	0.11	**0.04**	0.03	0.05
Transportation and Blending	**0.12**	**0.13**	0.10	0.11	0.11	0.10	**0.11**	0.10	0.12
Operating	**1.15**	**1.06**	1.23	1.20	1.25	1.16	**1.20**	1.14	1.26
Production and Mineral Taxes	**-**	**-**	-	0.01	0.02	0.01	**0.01**	0.02	0.01
Netback	**0.58**	**0.30**	0.89	1.53	1.30	1.62	**1.58**	1.53	1.61
Total [(1)] [(2)] *($/BOE)*									
Price	**21.41**	**27.56**	15.43	30.67	24.78	29.95	**33.91**	40.50	27.73
Royalties	**1.16**	**1.51**	0.82	1.40	1.23	1.36	**1.51**	2.13	0.93
Transportation and Blending	**4.79**	**5.07**	4.51	4.21	4.43	4.35	**4.03**	3.95	4.11
Operating	**9.52**	**8.89**	10.14	10.72	10.43	10.18	**11.15**	10.78	11.49
Production and Mineral Taxes	**0.10**	**0.12**	0.08	0.18	0.10	0.19	**0.22**	0.27	0.17
Netback	**5.84**	**11.97**	(0.12)	14.16	8.59	13.87	**17.00**	23.37	11.03
Realized Gain (Loss) on Risk Management									
Liquids *($/bbl)*	**5.11**	**1.97**	8.16	7.51	11.39	10.07	**4.27**	1.75	6.58
Natural Gas *($/Mcf)*	**-**	**-**	-	0.37	0.42	0.37	**0.34**	0.39	0.29
Total [(2)] *($/BOE)*	**3.81**	**1.46**	6.08	6.11	9.08	8.07	**3.67**	1.92	5.31

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

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

ADVISORY

FINANCIAL INFORMATION

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

Non-GAAP Measures

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

- Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains, less realized losses on risk management activities and is used to provide a consistent measure of the cash generating performance of the company's assets for comparability of Cenovus's underlying financial performance between periods. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.
- Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim and annual Consolidated Financial Statements. Cash flow is a measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations.
- Free cash flow is defined as cash flow less capital investment.
- Operating earnings is used to provide a consistent measure of the comparability of the company's underlying financial performance between periods by removing non-operating items. Operating earnings is defined as earnings before income tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on operating earnings (loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.
- Debt to capitalization, net debt to capitalization, debt to adjusted EBITDA and net debt to adjusted EBITDA are ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion. Net debt is defined as debt net of cash and cash equivalents. Capitalization is defined as debt plus shareholders' equity. Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity. Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill and asset impairments, unrealized gains or losses on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss, calculated on a trailing 12-month basis.

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

Netbacks reported in this quarterly report are calculated as set out in the Annual Information Form (AIF). Heavy oil prices and transportation and blending costs exclude the costs of purchased condensate, which is blended with heavy oil. For the second quarter of 2016, the cost of condensate on a per-barrel of unblended crude oil basis was as follows: Christina Lake – $26.24 and Foster Creek – $24.76.

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively “forward-looking information”) about Cenovus's current expectations, estimates and projections, made in light of the company's experience and perception of historical trends. Forward-looking information in this document is identified by words such as “anticipate”, “expect”, “estimate”, “plan”, “target”, “position”, “project”, “capacity”, “potential”, “may”, “on track”, “confidence” or similar expressions and includes suggestions of future outcomes, including statements about: milestones and schedules, including expected timing for new oil sands expansion phases; potential for resumption of deferred project construction; projections for 2016 and future years; forecast operating and financial results; targets for our debt to capitalization and debt to EBITDA ratios; planned capital expenditures; expected future production, including the timing, stability or growth thereof; our ability to preserve our financial resilience and plans and strategies with respect thereto; achieved and forecast cost savings and sustainability thereof; and dividend strategy. 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 2016 guidance (as updated on July 28, 2016), available at cenovus.com; projected capital investment levels, flexibility of capital spending plans and associated source of funding; future cost reductions; sustainability of cost reductions; 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; ability to obtain necessary regulatory and partner approvals; successful and timely implementation of capital projects or stages thereof; the company's ability to generate sufficient cash flow to meet its current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the company's filings with securities regulatory authorities.

The risk factors and uncertainties that could cause the company's actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of the company's risk management program, including the impact of derivative financial instruments, the success of hedging strategies and the sufficiency of liquidity position; accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in Cenovus's marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of the company's crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; ability to maintain relationships with partners and to successfully manage and operate the company's integrated business; reliability of assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; 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 fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to Cenovus's business; risks associated with climate change; the timing and costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and ability to attract and retain, critical talent; changes in labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental (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 Cenovus's business, financial results and consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries of operation; 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.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a discussion of Cenovus's material risk factors, see "Risk Factors" in the company's AIF or Form 40-F for the period ended December 31, 2015, together with the updates under "Risk Management" in each of the company's first quarter 2016 and second quarter 2016 MD&A, available on SEDAR at sedar.com, EDGAR at sec.gov and on the company's website at cenovus.com.

ABBREVIATIONS

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

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

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