UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

[Check one]

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**
OR

☑ **ANNUAL REPORT PURSUANT TO SECTION 13(a) or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2016 Commission File Number: 1-34513

CENOVUS ENERGY INC.

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial
Classification Code Number (if applicable))

Not applicable
(I.R.S. Employer
Identification Number (if applicable))

2600, 500 Centre Street S.E.
Calgary, Alberta, Canada T2G 1A6
(403) 766-2000
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 8th Avenue
New York, New York 10011
(212) 894-8641
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common shares, no par value (together with associated common share purchase rights)	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None
(Title of Class)

For annual reports indicate by check mark the information filed with this Form:

☑ Annual information form ☑ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

833,289,845

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☐ No ☐

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933, as amended: Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165) and Form F-10 (File No. 333-209490).

Principal Documents

The following documents have been filed as part of this annual report on Form 40-F, beginning on the following page:

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2016.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2016.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2016.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2016.

Cenovus Energy Inc.

Annual Information Form

For the Year Ended December 31, 2016

February 15, 2017

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FORWARD-LOOKING INFORMATION

In this Annual Information Form ("AIF"), unless otherwise specified or the context otherwise requires, references to "we", "us", "our", "its", "the Corporation" or "Cenovus" mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries.

This AIF contains forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the Corporation's experience and perception of historical trends. This forward-looking information is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "may", "strategy", "forward", "opportunity", "schedule", "on track" or similar expressions and includes suggestions of future outcomes, including statements about: Cenovus's strategy and related milestones and schedules including with respect to the development and growth of our business and operations; projected future value; projections for 2017 and future years; forecast operating and financial results, including forecast sales prices and costs; planned capital expenditures, including the amount, timing and financing thereof; annual capital investment forecasts and plans with respect thereto; techniques expected to be used to recover reserves and forecasts of the timing thereof; future abandonment and reclamation costs and the timing of payments in relation thereto; expected recovery of income taxes; potential impacts of various identified risk factors; expected future production, including the timing, stability or growth thereof; expected reserves and related information, including future net revenue and future development costs; broadening market access; expected capacities, including for projects, transportation and refining; improving cost structures, forecast cost savings and the sustainability thereof; dividend plans and strategy; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and trends and expected impacts to Cenovus; and future use and development of technology, including expected effects on environmental impact. Readers are cautioned not to place undue reliance on forward-looking information as the Corporation's actual results may differ materially from those expressed or implied.

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

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of Cenovus's material risk factors, see "Risk Factors" in this AIF. Readers should also refer to "Risk Management" in the Corporation's current Management's Discussion and Analysis ("MD&A") and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities, available on SEDAR at sedar.com, on EDGAR at sec.gov and on the Corporation's website at cenovus.com.

Information on or connected to our website cenovus.com does not form part of this AIF.

CORPORATE STRUCTURE

Cenovus Energy Inc. was formed under the *Canada Business Corporations Act* ("CBCA") by amalgamation of 7050372 Canada Inc. ("7050372") and Cenovus Energy Inc. (formerly Encana Finance Ltd. and referred to as "Subco") on November 30, 2009 pursuant to an arrangement under the CBCA (the "Arrangement") involving, among others, 7050372, Subco and Encana Corporation ("Encana"). On January 1, 2011, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Court of Queen's Bench of Alberta. On July 31, 2015, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary, 9281584 Canada Limited (formerly 1528419 Alberta Ltd.), by way of a vertical short-form amalgamation.

The Corporation's head and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6.

INTERCORPORATE RELATIONSHIPS

Cenovus's material subsidiaries and partnerships as at December 31, 2016 are as follows:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance, Formation or Organization
Cenovus FCCL Ltd.	100	Alberta
Cenovus Energy Marketing Services Ltd.	100	Alberta
Cenovus US Holdings Inc.	100	Delaware
FCCL Partnership ("FCCL")(2)	50	Alberta
WRB Refining LP ("WRB")(3)	50	Delaware

(1) Reflects all voting securities of all subsidiaries and partnerships beneficially owned, or controlled or directed, directly or indirectly, by Cenovus.
(2) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL.
(3) Cenovus non-operating interest held through Cenovus American Holdings Ltd. and Cenovus US Holdings Inc.

The Corporation's remaining subsidiaries and partnerships each account for (i) less than 10 percent of the Corporation's consolidated assets as at December 31, 2016 and (ii) less than 10 percent of the Corporation's consolidated revenues for the year ended December 31, 2016. In aggregate, Cenovus's unidentified subsidiaries and partnerships did not exceed 20 percent of the Corporation's total consolidated assets or total consolidated revenues as at and for the year ended December 31, 2016.

GENERAL DEVELOPMENT OF THE BUSINESS

OVERVIEW

Cenovus is an integrated oil company headquartered in Calgary, Alberta. The Corporation began independent operations on December 1, 2009 following the split of Encana into two independent publicly traded energy companies. Cenovus is in the business of developing, producing and marketing crude oil, NGLs and natural gas in Canada. Cenovus also conducts marketing activities and owns refining interests in the United States ("U.S.").

All of Cenovus's oil and natural gas reserves and production are located in Canada, within the provinces of Alberta and Saskatchewan. As at December 31, 2016, Cenovus had a land base of approximately 5.3 million net acres. The estimated proved reserves life index based on working interest production as at December 31, 2016 was approximately 27 years.

BUSINESS SEGMENTS

The Corporation's reportable segments are as follows:

Oil Sands

Cenovus's oil sands segment includes the development and production of bitumen and natural gas in northeast Alberta. Our 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

Cenovus's conventional segment includes the development and production of conventional crude oil(1), NGLs and natural gas(2) in Alberta and Saskatchewan, including the heavy oil(3) assets at Pelican Lake, the carbon dioxide ("CO_2") enhanced oil recovery ("EOR") project at Weyburn and emerging tight oil opportunities.

Refining and Marketing

Cenovus's refining and marketing segment includes transporting and selling crude oil and natural gas and joint ownership of 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

This segment primarily includes unrealized gains and losses recorded on derivative financial instruments and gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative ("G&A"), 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.

(1) *For the purpose of this AIF, references to "crude oil" means "heavy crude oil" and "light crude oil and medium crude oil combined" as those terms are defined in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").*
(2) *For the purpose of this AIF, references to "natural gas" means "conventional natural gas" as defined in NI 51-101.*
(3) *For the purpose of this AIF, references to "heavy oil" means "heavy crude oil" as defined in NI 51-101.*

THREE YEAR HISTORY

The following describes significant events that have influenced the development of Cenovus's business during the last three financial years:

2014

- **Regulatory approval received for Grand Rapids.** In the first quarter, Cenovus received regulatory approval for its Grand Rapids thermal oil sands project with an approved gross production capacity of up to 180,000 barrels per day.

- **Prepayment of Partnership contribution payable.** In the first quarter, Cenovus prepaid its US$2.7 billion partnership contribution payable to WRB, of which Cenovus is a 50 percent owner. This resulted in a net cash payment of approximately US$1.35 billion from Cenovus.

- **Divestiture of non-core assets.** In the second quarter, Cenovus completed the sale of certain of its Bakken assets to an unrelated third party for net proceeds of $35 million. In the third quarter, Cenovus completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million.

- **First production from Foster Creek phase F.** In the third quarter, Foster Creek phase F achieved first oil production. Phase F added 30,000 barrels per day of gross production capacity.

- **Increased rail takeaway capacity.** In 2014, Cenovus entered long-term commitments increasing rail takeaway capacity to 30,000 barrels per day.

- **Regulatory approval received for Foster Creek phase J.** In the fourth quarter, Cenovus received regulatory approval for Foster Creek phase J with approved gross production capacity of 50,000 barrels per day.

- **Regulatory approval received for Telephone Lake.** In the fourth quarter, Cenovus received regulatory approval for its 100 percent owned Telephone Lake thermal oil sands project with initial production capacity of 90,000 barrels per day. The project is expected to have gross production capacity in excess of 300,000 barrels per day.

2015

- **Reduced capital spending.** Due to the low commodity price environment, Cenovus reduced its 2015 capital spending, including suspension of the bulk of its conventional drilling program in southern Alberta and Saskatchewan and deferral of further construction work on Foster Creek phase H, Christina Lake phase G and Narrows Lake phase A.

- **Common share issuance.** In the first quarter, Cenovus issued 67.5 million common shares at a price of $22.25 per share for net proceeds of approximately $1.4 billion, a portion of which contributed to funding the Corporation's capital investment in 2015.

- **Permit approval received at Wood River Refinery.** In the first quarter, permit approval was received on the Wood River Refinery debottlenecking project.

- **Sale of royalty interest and mineral fee title lands business.** In the third quarter, Cenovus sold its wholly owned subsidiary, Heritage Royalty Limited Partnership ("HRP"), which held approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba along with gross overriding royalties on Cenovus's Pelican Lake property in northern Alberta and its EOR project at Weyburn, Saskatchewan to an unrelated third party for gross cash proceeds of $3.3 billion, a portion of which was used to help fund the Corporation's capital investment in 2015. Associated third party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day.

- **Rail terminal purchase.** In the third quarter, Cenovus purchased a crude-by-rail terminal located in Bruderheim, Alberta for $75 million, plus closing adjustments.

- **Cost reductions.** Cenovus achieved total 2015 cost savings of approximately $540 million, including operating, capital and G&A costs compared with its original 2015 budget. The cost reductions were achieved across the Corporation and included savings related to improved drilling efficiency, optimized scheduling and prioritization of repair and maintenance activities, lower chemical costs and improved oil sands waste disposal and handling processes. Additional savings resulted from the deferral of certain capital expenditure projects.

- **Workforce reductions.** Cenovus reduced its workforce by approximately 1,500 staff, including full- and part-time employees as well as contract workers. As at December 31, 2015, the Company had approximately 24 percent fewer employee and contractor workforce than it had at December 31, 2014.

- **Completed Christina Lake optimization.** In the fourth quarter, the Christina Lake optimization program began steam circulation, adding 22,000 barrels per day gross production capacity, taking total gross production capacity to 160,000 barrels per day.

- **Regulatory approval received for Christina Lake phase H.** In the fourth quarter, Cenovus received regulatory approval for Christina Lake phase H with approved gross production capacity of 50,000 barrels per day.

2016

- **Reduced spending.** Cenovus achieved its 2016 target of reducing planned capital, operating and G&A spending by $500 million compared with its original 2016 budget.

- **Workforce reductions.** In the second quarter, Cenovus further reduced its workforce by approximately 440 staff.

- **First production from Foster Creek phase G.** In the third quarter, Foster Creek phase G achieved first oil production. Phase G is expected to add 30,000 barrels per day of gross production capacity.

- **Wood River debottlenecking project completed.** In the third quarter, the Wood River debottlenecking project was successfully completed.

- **First production from Christina Lake phase F.** In the fourth quarter, Christina Lake phase F achieved first oil production. Phase F is expected to add 50,000 barrels per day of gross production capacity. The phase F expansion includes a 100 gross megawatt cogeneration plant.

2017

- **Resuming Christina Lake phase G expansion.** Cenovus anticipates it will resume the phase G expansion, which has an approved design capacity of 50,000 gross barrels per day. First oil from phase G is expected in the second half of 2019.

OIL SANDS

Oil Sands includes Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake, as well as emerging projects such as Grand Rapids and Telephone Lake. The Corporation's Athabasca natural gas assets also form part of this segment.

Joint Operations

Foster Creek, Christina Lake and Narrows Lake are jointly owned through FCCL with ConocoPhillips, an unrelated U.S. public company. Cenovus FCCL Ltd., Cenovus's wholly owned subsidiary, is the operator, managing partner and owner of 50 percent of FCCL. FCCL has a management committee, which is composed of three Cenovus representatives and three ConocoPhillips representatives, with each company holding equal voting rights.

Development Approach

Cenovus applies a manufacturing-like, phased approach to developing its oil sands assets. This approach incorporates learnings from previous phases into future growth plans, helping the Corporation to minimize costs.

New Technology

Cenovus continues to focus on technologies which are targeted to improve business performance and materially increase shareholder value amid continuing price uncertainty, a low carbon future, increased environmental protection pressure and regulatory changes. Technology development is a critical necessity to stay competitive and to sustain a social licence to operate.

Cenovus collaborates with industry cleantech entrepreneurs and universities around the world with the goal of accelerating environmental and carbon emission solutions.

Efforts are focused on demonstrating a number of potentially impactful technologies. Specifically, efforts are focused on three major areas:

- Accelerate production and achieve significant GHG emissions intensity reduction by injecting solvents. Solvent-aided process ("SAP") is a technology that has the potential to significantly improve the steam to oil ratio ("SOR").
- Reduce diluent requirements and the total acid number ("TAN") of crude oil through the use of technologies such as partial upgrading. Partial upgrading technologies produce products which may significantly reduce costs associated with diluent purchase and transportation.
- Reduce costs of existing and future operations by using innovative facility design which simplify plant facilities and reduce environmental footprint.

Landholdings

As at December 31, 2016, Cenovus held bitumen rights of approximately 1.9 million gross acres (1.5 million net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 478,000 acres on Cenovus's behalf and/or its assignee's behalf on the Cold Lake Air Weapons Range.

The following table summarizes Cenovus's Oil Sands landholdings as at December 31, 2016, all of which are located within the Province of Alberta:

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest[(1)]
Foster Creek	16	8	114	57	130	65	50%
Christina Lake	9	5	50	25	59	30	50%
Narrows Lake	-	-	27	13	27	13	50%
Grand Rapids[(2)]	-	-	61	61	61	61	100%
Telephone Lake	16	16	142	142	158	158	100%
Athabasca	384	345	448	380	832	725	87%
Other	28	10	1,537	1,252	1,565	1,262	81%
Total	453	384	2,379	1,930	2,832	2,314	82%

(1) Percentages represented in the above table cannot be calculated based on acreage shown due to rounding.
(2) Overlapping landholdings between Grand Rapids and Pelican Lake (included in the Conventional segment) have been allocated to Grand Rapids based on the project's approved development area.

Production

The following table summarizes Cenovus's share of daily average production for the periods indicated:

(annual average)	Bitumen (bbls/d) 2016	Bitumen (bbls/d) 2015	Natural Gas (MMcf/d) 2016	Natural Gas (MMcf/d) 2015	Total Production (BOE/d) 2016	Total Production (BOE/d) 2015
Foster Creek	**70,244**	65,345	**-**	-	**70,244**	65,345
Christina Lake	**79,449**	74,975	**-**	-	**79,449**	74,975
Athabasca[(1)]	**-**	-	**17**	19	**2,833**	3,167
Total	**149,693**	140,320	**17**	19	**152,526**	143,487

(1) *Net of internal usage of natural gas used at Foster Creek to produce steam.*

Producing Wells

The following table summarizes Cenovus's interests in producing wells as at December 31, 2016. These figures exclude wells which were capable of producing, but that were not producing as at December 31, 2016:

(number of wells)	Producing Bitumen Wells Gross	Producing Bitumen Wells Net	Producing Gas Wells Gross	Producing Gas Wells Net	Total Producing Wells Gross	Total Producing Wells Net
Foster Creek	294	147	-	-	294	147
Christina Lake	196	98	-	-	196	98
Athabasca	-		293	279	293	279
Total	490	245	293	279	783	524

Foster Creek

Cenovus has a 50 percent working interest in Foster Creek. It is located on the Cold Lake Air Weapons Range, an active military base, and has a reservoir depth up to 500 meters below the surface. Foster Creek produces from the McMurray formation using steam-assisted gravity drainage ("SAGD") technology.

The Corporation holds surface access rights from the governments of Canada and Alberta and bitumen rights from the Government of Alberta for exploration, development and transportation from areas within the Cold Lake Air Weapons Range. In addition, Cenovus holds exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on the Corporation's and/or its assignee's behalf.

Production from phases A through G at Foster Creek averaged 70,244 barrels per day in 2016. Phase G was completed in the third quarter of 2016. Phase G is expected to add approximately 30,000 gross barrels per day of nameplate capacity and ramp up to its operational capacity in approximately 12 months from start-up. Expansion work on phase H has been deferred in response to the low commodity price environment.

Cenovus operates a 98 gross megawatt natural gas-fired cogeneration facility in conjunction with Foster Creek. The steam and power generated by the facility is presently being used within the SAGD operation and any excess power generated is being sold into the Alberta Power Pool.

Christina Lake

Cenovus has a 50 percent working interest in Christina Lake. Christina Lake is located approximately 120 kilometers south of Fort McMurray and has a reservoir depth up to 350 meters below the surface. Christina Lake produces from the McMurray formation using SAGD technology.

Production from phases A through F at Christina Lake averaged 79,449 barrels per day in 2016. Phase F was completed in the fourth quarter of 2016, and is expected to add approximately 50,000 gross barrels per day of nameplate capacity and ramp up to its operational capacity in approximately 12 months from start-up. This expansion includes a 100 gross megawatt natural gas-fired cogeneration facility. The steam and power generated by the facility is presently being used within the SAGD operation and any excess power generated is being sold into the Alberta Power Pool. Cenovus plans to resume work on the phase G expansion in 2017, which was deferred in late 2014 due to the low commodity price environment. Phase G has an approved design capacity of 50,000 gross barrels per day and first oil from the expansion is expected in the second half of 2019.

Narrows Lake

Cenovus has a 50 percent working interest in Narrows Lake. Narrows Lake is located adjacent to Christina Lake and has a reservoir depth up to 375 meters below the surface. Narrows Lake will be Cenovus's first commercial application of SAP in conjunction with SAGD.

In 2012, Cenovus received regulatory approval for phases A, B and C for 130,000 gross barrels per day of production capacity and partner approval for phase A, a 45,000 gross barrels per day phase. Initial work on phase A commenced in the third quarter of 2013. Due to the low commodity price environment, Cenovus has deferred new construction spending on phase A. It is expected that the future development of Narrows Lake will benefit from the existing infrastructure and resources at Christina Lake, which is expected to lower overall costs.

Telephone Lake

Cenovus's 100 percent owned Telephone Lake property is located in the Borealis Region in northeastern Alberta, approximately 90 kilometers northeast of Fort McMurray.

Cenovus continues to advance development plans for Telephone Lake after receiving approval from the Alberta Energy Regulator ("AER") in late 2014 for a SAGD project with initial production capacity of 90,000 barrels per day.

Telephone Lake is a unique oil sands project because directly above the oil there is a layer of groundwater that is not suitable for human consumption without treatment (referred to as top water). The top water layer is between 150 and 175 meters below the surface. In 2013, Cenovus completed a dewatering pilot project at Telephone Lake displacing approximately 70 percent of the top water. Although dewatering is not essential to the development of Telephone Lake, Cenovus believes this method will make oil recovery more efficient and help reduce its impact on the environment by reducing the SOR.

Grand Rapids

Cenovus's 100 percent owned Grand Rapids property is located in the Greater Pelican Region, about 300 kilometers north of Edmonton, Alberta. The project is adjacent to the Corporation's Pelican Lake heavy oil operations and existing facilities.

In December 2010, the Corporation drilled its first pilot SAGD well pair at Grand Rapids. A second well pair was drilled in early 2012 and a third well pair commenced steam circulation in 2015.

In March 2014, Cenovus received regulatory approval from the AER for its Grand Rapids SAGD project with total production capacity of 180,000 barrels per day. As of February 2016, further activity in respect of the SAGD pilot at Grand Rapids has been deferred in response to the low commodity price environment.

Other Emerging Assets

Cenovus has a number of emerging assets, including the Steepbank and East McMurray properties located in the Borealis Region in northeastern Alberta, which it continues to evaluate, manage and work to decrease risk associated with potential future development of these assets. Cenovus continues to believe in the long-term potential of its emerging projects as a future resource base.

Athabasca Gas

Cenovus produces natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeastern Alberta. Cenovus holds surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range that were granted by the governments of Canada and Alberta. The majority of the Corporation's natural gas production in the area is processed through compression facilities, wholly-owned and operated by Cenovus.

Natural gas production continues to be impacted by the AER's decisions made between 2003 and 2015 to shut-in natural gas production from the McMurray, Wabiskaw and Clearwater formations that may put the recovery of bitumen resources in the area at risk. This resulted in a decrease in the Corporation's annualized natural gas production of approximately 13 million cubic feet per day in 2016 (2015 - 14 million cubic feet per day). The Alberta Department of Energy has provided a 10 year royalty credit which can equal up to 50 percent of lost cash flows to help offset the impact of the shut-in wells. This royalty credit fluctuates with the price of natural gas.

Capital Investment

In 2016, the Corporation's Oil Sands capital investment was $604 million, primarily related to sustaining existing production and the completion of the Foster Creek phase G and Christina Lake phase F facilities. The production capacity for these projects is approximately 390,000 gross barrels per day. Ramp up to full production volumes for these phases is expected to extend into 2017.

- Capital at Foster Creek was focused on sustaining capital related to existing production, completing expansion phase G and the drilling of stratigraphic test wells to determine pad placement for sustaining well pads and near-term phase expansions.
- Capital at Christina Lake was focused on sustaining capital related to existing production, completing expansion phase F and the drilling of stratigraphic test wells to determine pad placement for sustaining well pads and near-term phase expansions.
- Capital at Narrows Lake was focused on engineering work.
- Capital at Telephone Lake was focused on front end engineering work on the central processing facility.
- Capital at Grand Rapids was limited to the wind down of the SAGD pilot.

2017 capital spending is planned to be focused on sustaining current production levels from existing oil sands facilities and construction at Christina Lake phase G. Additional capital will be spent on existing and emerging oil sands assets.

CONVENTIONAL

Conventional operations include the development and production of conventional crude oil, NGLs and natural gas from assets in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the CO_2 EOR project near Weyburn, Saskatchewan and emerging tight oil assets in Alberta. The established assets in this segment are strategically important due to their long life reserves, stable operations and diversity of crude oil produced.

In July of 2015, Cenovus sold HRP, the holder of Cenovus's royalty interest and mineral fee title lands business in Alberta, Saskatchewan and Manitoba to an unrelated third party for gross cash proceeds of $3.3 billion. Associated third party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day. With this disposition Cenovus also retained an option to acquire from HRP leases at pre-determined rates and lease terms for up to five years on more than 800,000 acres in zones of the fee lands currently being developed by Cenovus, with an option for a further five years on approximately 800,000 acres to select leases on half of the remaining undeveloped acreage.

At the beginning of 2015, Cenovus announced the suspension of the bulk of its conventional drilling program in southern Alberta due to the low commodity price environment. After a slight recovery in price, Cenovus resumed its tight oil program in the latter half of 2016 with the restart of stratigraphic test well and horizontal well drilling.

Conventional operations also include leases of Crown lands primarily in the Suffield and Pelican Lake areas and in Saskatchewan.

Landholdings

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest[1]
Alberta							
Grassland[2]	882	843	41	37	923	880	95%
Suffield	932	920	51	50	983	970	99%
Langevin[3]	578	562	60	58	638	620	97%
Pelican Lake	95	94	248	241	343	335	98%
Wainwright	32	13	7	4	39	17	42%
Other	23	15	134	120	157	135	86%
Saskatchewan							
Weyburn	46	35	9	7	55	42	74%
Bakken	3	1	12	8	15	9	64%
Total	2,591	2,483	562	525	3,153	3,008	95%

(1) Percentages as represented in the above table cannot be calculated based on acreage shown due to rounding.
(2) Grassland is located in the Drumheller and Brooks areas.
(3) Langevin is located northwest of Medicine Hat.

Production

The following table summarizes Cenovus's share of daily average production[1] for the periods indicated:

	Crude Oil and NGLs (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
(annual average)	**2016**	2015	**2016**	2015	**2016**	2015
Alberta						
Grassland[2]	**5,913**	7,248	**193**	212	**38,080**	42,581
Suffield	**7,724**	8,854	**112**	125	**26,391**	29,687
Langevin[3]	**6,055**	8,025	**72**	84	**18,055**	22,025
Pelican Lake	**21,224**	24,421	**-**	-	**21,224**	24,421
Wainwright	**253**	1,638	**-**	1	**253**	1,805
Other	**4**	10	**-**	-	**4**	10
Saskatchewan						
Weyburn	**14,969**	15,732	**-**	-	**14,969**	15,732
Bakken	**23**	699	**-**	-	**23**	699
Total	**56,165**	66,627	**377**	422	**118,999**	136,960

(1) Includes production from mineral fee title lands in which Cenovus has a working interest and mineral fee title lands in which Cenovus has retained a royalty interest. In the third quarter of 2015, Cenovus sold those royalty interests.
(2) Grassland is located in the Drumheller and Brooks areas.
(3) Langevin is located northwest of Medicine Hat.

Producing Wells

The following table summarizes Cenovus's interests in producing wells[1] as at December 31, 2016. These figures exclude wells which were capable of producing, but that were not producing, as at December 31, 2016:

(number of wells)	Producing Oil Wells Gross	Producing Oil Wells Net	Producing Gas Wells Gross	Producing Gas Wells Net	Total Producing Wells Gross	Total Producing Wells Net
Alberta						
Grassland[2]	362	356	8,733	8,591	9,095	8,947
Suffield	684	684	10,623	10,605	11,307	11,289
Langevin[3]	273	271	4,765	4,754	5,038	5,025
Pelican Lake	585	585	1	1	586	586
Wainwright	9	6	5	1	14	7
Other	10	5	1	-	11	5
Saskatchewan						
Weyburn	637	401	-	-	637	401
Bakken	8	1	-	-	8	1
Total	2,568	2,309	24,128	23,952	26,696	26,261

(1) Includes wells on mineral fee title lands where Cenovus has a working interest.
(2) Grassland is located in the Drumheller and Brooks areas.
(3) Langevin is located northwest of Medicine Hat.

Conventional Crude Oil Assets

Cenovus's extensive conventional crude oil assets are located in Alberta and Saskatchewan. Cenovus holds interests in multiple zones in the Suffield, Grassland and Langevin areas in Alberta with a mix of medium and heavy crude oil production. Cenovus uses a number of EOR techniques to increase production of the Corporation's oil assets, including waterflooding, CO_2 miscible flooding and alkaline surfactant polymer flooding.

Cenovus operates one of the world's largest CO_2 miscible flood projects. The Weyburn unit produces medium sour crude oil and covers approximately 50,000 acres of land in southeastern Saskatchewan. As at December 31, 2016, approximately 64 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 30 million tonnes of CO_2 have been injected. The CO_2 is delivered by pipeline directly to the Weyburn facility from a coal gasification project in North Dakota, U.S. and from the Boundary Dam Power Station in southeast Saskatchewan. In the unitized portion of the Weyburn field in southeastern Saskatchewan, Cenovus has a 62.1 percent working interest. However, after taking into consideration net royalty obligations to third parties, Cenovus's economic interest is 50.4 percent. Cenovus is the unit operator and owns 62.1 percent of the CO_2 pipeline from the Boundary Dam to Weyburn.

Using a patterned, horizontal well polymer flood and waterflood, Cenovus produces heavy crude oil from the Wabiskaw formation at its Pelican Lake property. The property is located within the Greater Pelican Region in northeastern Alberta. Cenovus holds a 38 percent non-operated interest in a 110 kilometer, 20 inch diameter crude oil pipeline which connects the Pelican Lake area to major pipelines that transport crude oil from northern Alberta to crude oil markets.

Net Wells Drilled and Production

The following table summarizes net production oil wells drilled and daily average oil production figures[1] for the periods indicated:

	Net Wells Drilled		Average Production[2] (bbls/d) Light & Medium Oil		Heavy Oil	
	2016	2015	**2016**	2015	**2016**	2015
Alberta						
Grassland[3]	**2**	15	**5,359**	6,632	**-**	-
Suffield	**-**	1	**-**	-	**7,707**	8,837
Langevin[4]	**6**	12	**5,939**	7,858	**-**	-
Wainwright	**-**	-	**-**	1	**253**	1,630
Pelican Lake	**-**	-	**-**	-	**21,224**	24,421
Other	**-**	-	**2**	10	**1**	-
Saskatchewan						
Weyburn	**1**	6	**14,593**	15,343	**-**	-
Bakken	**-**	-	**22**	642	**-**	-
Total	**9**	34	**25,915**	30,486	**29,185**	34,888

(1) Excludes wells drilled by third parties on mineral fee title lands. In the third quarter of 2015, Cenovus sold those fee lands.
(2) Includes production from mineral fee title lands in which Cenovus has a working interest and mineral fee title lands in which Cenovus had retained a royalty interest. In the third quarter of 2015, Cenovus sold those fee lands.
(3) Grassland landholdings are located in the Drumheller and Brooks areas.
(4) Langevin landholdings are located northwest of Medicine Hat.

Conventional Gas Assets

Cenovus holds natural gas interests in multiple zones in the Suffield, Grassland and Langevin areas in Alberta. Development in these areas has focused on recompletions and optimization of existing wells.

Suffield is one of the core areas of the Corporation's crude oil and natural gas production in Alberta. The Suffield area is largely made up of the Suffield Block, where operations are carried out pursuant to an agreement among Cenovus, the Government of Canada and the Province of Alberta governing surface access to Canadian Forces Base ("CFB") Suffield. In 1999, the parties agreed to permit access to the Suffield military training area to additional operators. Cenovus's predecessor companies, Alberta Energy Company Ltd. and Encana, have operated at CFB Suffield for over 30 years.

The Corporation's natural gas production acts as an economic hedge for the natural gas required as a fuel source at its oil sands operations and the U.S. refineries in which it has joint interest.

In 2016, Conventional natural gas production averaged 377 MMcf per day (2015 – 422 MMcf per day). Cenovus did not drill any gas wells in 2016 or 2015.

Capital Investment

In 2016, the Corporation's Conventional capital investment was $171 million, primarily related to stratigraphic drilling activity at our tight oil projects in southern Alberta and for maintenance and CO_2 injection at our EOR project at Weyburn. Spending on natural gas activities was allocated to a small number of higher return opportunities.

REFINING AND MARKETING

Refining and Marketing reflects U.S. refining interests and coordinates Cenovus's marketing and transportation initiatives to optimize the value received for its products.

Refining

The refining operations allow Cenovus 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.

Through WRB, Cenovus has a 50 percent ownership interest in both the Wood River and Borger refineries located in Roxana, Illinois and Borger, Texas, respectively. Phillips 66, an unrelated U.S. public company, is the operator and managing partner of WRB. WRB has a management committee, which is composed of three Cenovus representatives and three Phillips 66 representatives, with each company holding equal voting rights. The refineries have a combined stated processing capacity of approximately 460,000 gross barrels per day of crude oil, including heavy crude oil processing capability of up to 255,000 gross barrels per day. In addition, the Borger Refinery has an NGL fractionation facility with a capacity of 45,000 gross barrels per day.

The following table summarizes the key operational results for the refineries in the periods indicated:

Refinery Operations[(1)]	2016	2015
Crude Oil Capacity (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**444**	419
Heavy Oil	**233**	200
Light & Medium Oil	**211**	219
Crude Utilization (%)	**97**	91
Refined Products (Mbbls/d)		
Gasoline	**236**	228
Distillates	**146**	137
Other	**90**	79
Total	**471**	444

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

Wood River Refinery

The Wood River Refinery ranks in the top 10 percent of approximately 150 refineries in the U.S., based on total crude oil capacity. It is located in Roxana, Illinois, approximately 25 kilometers northeast of St. Louis, Missouri. The Wood River Refinery processes light low-sulphur and heavy high-sulphur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstock as well as coke and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper U.S. Midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the U.S. Midwest.

The Wood River Refinery's stated crude oil processing capacity for 2016 was 314,000 gross barrels per day, and was unchanged from 2015. Since the completed coker construction and start-up of the coker and refinery expansion project, the Wood River Refinery increased its total Canadian heavy crude oil processing capacity up to 220,000 gross barrels per day. In 2016, almost two-thirds of the crude oil processed at the Wood River Refinery consisted of Canadian heavy crude oil, including a significant proportion of high TAN crudes.

Borger Refinery

The Borger Refinery is located in Borger, Texas, approximately 80 kilometers north of Amarillo, Texas. The Borger Refinery processes mainly medium and heavy high-sulphur crude oil, and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the U.S. Mid-Continent.

The Borger Refinery's stated oil processing capacity for 2016 was 146,000 gross barrels per day, including 35,000 gross barrels per day of heavy crude oil. The Borger Refinery also has an NGL fractionation facility with stated capacity of 45,000 gross barrels per day. The stated processing capacity is unchanged from 2015.

Marketing

Cenovus's marketing activities are focused on enhancing the price of the Corporation's crude oil and natural gas production, including third party purchases and sales of crude oil and natural gas to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification. Cenovus's marketing activities are focused on the sale of production, management of condensate supply and optimization of our storage and transportation commitments. The prices Cenovus receives are based primarily on prevailing crude oil and natural gas index prices which are impacted by global and regional supply and demand factors.

Cenovus's marketing activities also include entering into various risk management contracts aimed at mitigating the impact of commodity price swings. Details of these transactions are provided in the notes to the Corporation's audited Consolidated Financial Statements for the year ended December 31, 2016.

Transportation

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production. As at December 31, 2016, Cenovus has entered into various firm transportation and storage commitments totaling $26 billion, $19 billion of which relate to pipelines that are subject to regulatory approval or have been approved but are not yet in service. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally. The Corporation's portfolio of transportation commitments includes feeder pipelines from its production areas to the Edmonton and Hardisty, Alberta trade centres and major pipeline alternatives to markets downstream of these hubs. Other transportation commitments are primarily related to the reliable supply of diluent, railcar transportation as well as tankage and terminalling of both crude oil blend and condensate volumes. Cenovus's transportation portfolio includes a crude-by-rail terminal located at Bruderheim, Alberta.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As a Canadian issuer, Cenovus is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of the Corporation's reserves in accordance with NI 51-101.

The Corporation's reserves are located in Alberta and Saskatchewan, Canada. Cenovus retained two independent qualified reserves evaluators ("IQREs"), McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of its bitumen, heavy oil, light and medium oil[(1)], NGLs, natural gas, and coal bed methane ("CBM") proved and probable reserves. McDaniel evaluated approximately 97 percent of Cenovus's proved reserves, located in Alberta, and GLJ evaluated approximately three percent of the Corporation's proved reserves, located in Saskatchewan.

The reserves committee (the "Reserves Committee") of Cenovus's board of directors (the "Board"), composed of independent directors, reviews the qualifications and appointment of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets independently with management of Cenovus ("Management") and each IQRE to determine whether any restrictions affect the ability of the IQREs to report on the reserves data without reservation. In addition, the Reserves Committee reviews the reserves data and the report of the IQREs and provides a recommendation regarding approval of the reserves disclosure to the Board.

Cenovus's bitumen reserves will be recovered and produced using SAGD technology. SAGD involves injecting steam into horizontal wells drilled into the bitumen formation and recovering heated bitumen and water from producing wells located below the injection wells. This technique has a surface footprint comparable to conventional oil production. Cenovus has no bitumen reserves that require mining techniques to recover the bitumen.

Classifications of reserves as proved or probable are only attempts to define the degree of certainty associated with the estimates. There are numerous uncertainties inherent in estimating quantities of petroleum reserves. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Readers should review the definitions and information contained in

"Additional Notes to Reserves Data Tables", "Definitions" and "Pricing Assumptions" in conjunction with the reserves disclosure. The reserves estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates disclosed. See "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates" in this AIF for additional information.

The reserves data and other oil and gas information contained in this AIF is dated February 15, 2017, with an effective date of December 31, 2016. McDaniel's preparation date of the information is January 11, 2017 and GLJ's preparation date is January 11, 2017.

(1) *For the purpose of this AIF, references to "light and medium oil" means "light crude oil and medium crude oil combined" as defined in NI 51-101.*

DISCLOSURE OF RESERVES DATA

The reserves data presented summarizes the Corporation's bitumen, heavy oil, light and medium oil and NGLs, and natural gas and CBM reserves and the net present values ("NPV") and future net revenue ("FNR") for these reserves. The reserves data uses forecast prices and costs prior to provision for interest, G&A expenses or the impact of any hedging activities. Estimates of FNR have been presented on a before and after income tax basis.

Summary of Company Interest Oil and Gas Reserves as at December 31, 2016

(Forecast prices and inflation)

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	304	92	84	634
Developed Non-Producing	33	8	2	13
Undeveloped	2,006	14	15	5
Proved Reserves	2,343	114	101	652
Probable Reserves	976	75	44	212
Proved plus Probable Reserves	3,319	189	145	864

After Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	244	75	65	593
Developed Non-Producing	25	7	1	11
Undeveloped	1,510	12	12	5
Proved Reserves	1,779	94	78	609
Probable Reserves	739	57	32	189
Proved plus Probable Reserves	2,518	151	110	798

Summary of Net Present Value of Future Net Revenue as at December 31, 2016

(Forecast prices and inflation)

Before Income Taxes	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%	Unit Value Discounted at 10 % [(1)] $/BOE
Proved Reserves						
Developed Producing	5,901	8,390	7,778	6,981	6,290	16.13
Developed Non-Producing	1,090	776	585	457	366	16.47
Undeveloped	58,133	22,973	11,087	6,101	3,642	7.22
Proved Reserves	65,124	32,139	19,450	13,539	10,298	9.48
Probable Reserves	30,389	12,221	5,807	3,211	1,987	6.76
Proved plus Probable Reserves	95,513	44,360	25,257	16,750	12,285	8.67

After Income Taxes[(2)]	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	3,986	6,847	6,498	5,901	5,366
Developed Non-Producing	827	591	453	361	293
Undeveloped	42,308	16,985	8,294	4,614	2,787
Proved Reserves	47,121	24,423	15,245	10,876	8,446
Probable Reserves	22,274	9,021	4,301	2,384	1,481
Proved plus Probable Reserves	69,395	33,444	19,546	13,260	9,927

(1) Unit values have been calculated using Company Interest After Royalties reserves.

(2) Values are calculated by considering existing tax pools and tax circumstances for Cenovus and its subsidiaries in the consolidated evaluation of Cenovus's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see the Corporation's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2016.

Total Future Net Revenue (undiscounted) as at December 31, 2016

(Forecast prices and inflation - $ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs[(1)]	Future Net Revenue Before Future Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved Reserves	183,743	44,492	46,364	18,378	9,385	65,124	18,003	47,121
Proved plus Probable Reserves	266,003	64,859	66,175	28,732	10,724	95,513	26,118	69,395

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Future Net Revenue by Product Type as at December 31, 2016

(Forecast prices and inflation)

Reserves Category	Product Types	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value Discounted at 10 % / year[(1)] ($/BOE)
Proved Reserves	Bitumen	17,212	9.68
	Heavy Oil	1,048	11.15
	Light & Medium Oil and NGLs	1,221	15.56
	Natural Gas	(31)	(0.31)
	Total	**19,450**	**9.48**
Proved plus Probable Reserves	Bitumen	21,772	8.65
	Heavy Oil	1,539	10.19
	Light & Medium Oil and NGLs	1,788	16.18
	Natural Gas	158	1.19
	Total	**25,257**	**8.67**

(1) Unit values have been calculated using Company Interest After Royalties reserves.

Additional Notes to Reserves Data Tables

- The estimates of FNR presented do not represent fair market value.
- FNR from reserves excludes cash flows related to Cenovus's risk management activities.
- For disclosure purposes, Cenovus has included NGLs with light and medium oil, and CBM with natural gas, as the reserves of each are not material relative to the other reported product types.
- In accordance with NI 51-101, NPV and FNR amounts presented include all of Cenovus's existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Definitions

1. **After Royalties** means volumes after deduction of royalties and includes royalty interest reserves, if any.
2. **Before Royalties** means volumes before deduction of royalties and excludes royalty interest reserves, if any.
3. **Company Interest** means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by Cenovus.
4. **Gross** means: (a) in relation to wells, the total number of wells in which Cenovus has an interest; and (b) in relation to properties, the total acreage of properties in which Cenovus has an interest.
5. **Net** means: (a) in relation to wells, the number of wells obtained by aggregating Cenovus's working interest in each of its gross wells; and (b) in relation to Cenovus's interest in a property, the total acreage in which it has an interest multiplied by its working interest.
6. **Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions, which are generally accepted as being reasonable, and are be disclosed later in this AIF.

Reserves are classified according to the degree of certainty associated with the estimates:

- **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories may be divided into developed and undeveloped categories:

- **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided as follows:
    - o **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - o **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Pricing Assumptions

The forecast of prices and inflation (the “McDaniel Forecast”) provided in the table below was obtained from McDaniel and used to estimate FNR associated with the reserves disclosed herein. The McDaniel Forecast is dated January 1, 2017. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs. For historical prices realized during 2016, see “Production History” in this AIF.

	Oil					Natural Gas & CBM		
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40 API (C$/bbl)	Cromer Medium 29.3 API (C$/bbl)	Alberta Heavy 12 API (C$/bbl)	Western Canadian Select (C$/bbl)	AECO Gas Price (C$/MMBtu)	Inflation Rate (%/year)	Exchange Rate (US$/C$)
2017	55.00	69.80	62.80	46.50	53.70	3.40	0.0	0.750
2018	58.70	72.70	67.60	50.50	58.20	3.15	2.0	0.775
2019	62.40	75.50	70.20	54.00	61.90	3.30	2.0	0.800
2020	69.00	81.10	75.40	58.00	66.50	3.60	2.0	0.825
2021	75.80	86.60	80.50	61.90	71.00	3.90	2.0	0.850
2022	77.30	88.30	82.10	63.10	72.40	3.95	2.0	0.850
2023	78.80	90.00	83.70	64.40	73.80	4.10	2.0	0.850
2024	80.40	91.80	85.40	65.60	75.30	4.25	2.0	0.850
2025	82.00	93.70	87.10	67.00	76.80	4.30	2.0	0.850
2026	83.70	95.60	88.90	68.40	78.40	4.40	2.0	0.850
2027	85.30	97.40	90.60	69.60	79.90	4.50	2.0	0.850
2028+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.850

Future Development Costs

The following table outlines undiscounted future development costs deducted in the estimation of FNR calculated utilizing forecast prices and inflation for the years indicated:

Reserves Category ($ millions)	2017	2018	2019	2020	2021	Remainder	Total
Proved Reserves	311	630	739	775	539	15,384	18,378
Proved plus Probable Reserves	426	717	1,033	1,160	880	24,516	28,732

Cenovus believes that existing cash balances, internally generated cash flows, existing credit facilities, management of its asset portfolio and access to capital markets will be sufficient to fund the Corporation’s future development costs. However, there can be no guarantee that the necessary funds will be available or that Cenovus will allocate funding to develop all of its reserves. Failure to develop those reserves would have a negative impact on the Corporation’s FNR.

The interest or other costs of external funding are not included in the reserves and FNR estimates and would reduce FNR depending upon the funding sources utilized. Cenovus does not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of Cenovus's Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas and CBM for the year ended December 31, 2016, presented using forecast prices and inflation. All reserves are located in Canada.

Proved	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2015	2,183	133	110	721
Extensions and Improved Recovery	154	-	-	-
Discoveries	-	-	-	-
Technical Revisions	61	(8)	1	79
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	(1)
Production(1)	(55)	(11)	(10)	(147)
As at December 31, 2016	2,343	114	101	652

Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2015	1,115	87	44	232
Extensions and Improved Recovery	-	-	-	-
Discoveries	-	-	-	-
Technical Revisions	(139)	(12)	-	(20)
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production(1)	-	-	-	-
As at December 31, 2016	976	75	44	212

Proved plus Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2015	3,298	220	154	953
Extensions and Improved Recovery	154	-	-	-
Discoveries	-	-	-	-
Technical Revisions	(78)	(20)	1	59
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	(1)
Production(1)	(55)	(11)	(10)	(147)
As at December 31, 2016	3,319	189	145	864

(1) Production used for the reserves reconciliation differs from publicly reported production. In accordance with NI 51-101, Company Interest Before Royalties production used for the reserves reconciliation above includes Cenovus's share of gas volumes provided to FCCL for steam generation, but does not include royalty interest production.

Proved bitumen reserves increased by approximately seven percent. Increases at Christina Lake were primarily a result of an area expansion and improved reservoir performance. Increases at Foster Creek were primarily a result of improved reservoir performance. Proved plus probable bitumen reserves increased one percent.

Heavy oil proved reserves decreased by approximately 14 percent primarily as a result of production and drilling deferrals. Heavy oil probable reserves decreased by approximately 14 percent due to drilling deferrals at Pelican Lake. Overall, heavy oil proved plus probable reserves decreased by approximately 14 percent.

Light and medium oil and NGLs proved reserves decreased by eight percent. The decreases were primarily due to production, partially offset by development at Grassland. Overall, light and medium oil and NGLs proved plus probable reserves decreased six percent, primarily as a result of production.

Natural gas and CBM proved reserves declined by approximately 10 percent as extensions and technical revisions did not offset production. Probable natural gas and CBM reserves and proved plus probable natural gas and CBM reserves declined by approximately nine percent.

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and probable undeveloped reserves have been estimated by the IQREs in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook. In general, undeveloped reserves are scheduled to be developed within the next one to 45 years.

Company Interest Proved Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior	1,875	1,629	94	47	59	15	300	4
2014	161	1,732	7	40	11	21	4	4
2015	238	1,861	-	29	1	19	1	4
2016	185	2,006	-	14	-	15	-	5

Company Interest Probable Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior	1,244	649	122	86	35	17	54	16
2014	649	1,293	5	76	8	15	7	11
2015	1	1,074	-	52	1	14	2	8
2016	10	935	-	46	-	15	-	9

DEVELOPMENT OF PROVED AND PROBABLE UNDEVELOPED RESERVES

Bitumen

At the end of 2016, Cenovus had proved undeveloped bitumen reserves of 2,006 million barrels Before Royalties, or approximately 86 percent of the Corporation's proved bitumen reserves. Of Cenovus's 976 million barrels of probable bitumen reserves, 935 million barrels, or approximately 96 percent, are undeveloped. The evaluation of these reserves anticipates they will be recovered using SAGD.

Typical SAGD project development involves the initial installation of a steam generation facility, at a cost much greater than drilling a production/injection well pair, and then progressively drilling sufficient SAGD well pairs to fully utilize the available steam.

Bitumen reserves can be classified as proved when there is sufficient stratigraphic drilling to have demonstrated to a high degree of certainty the presence of the bitumen in commercially recoverable volumes. McDaniel's standard for sufficient drilling in the McMurray formation is a minimum of eight wells per section with 3D seismic, or 16 wells per section with no seismic. In other geological formations, such as Grand Rapids, there may be some variation in the standard. Additionally, all requisite legal and regulatory approvals must have been obtained, operator and partner funding approvals must be in place, and a reasonable development timetable must be established. Proved developed bitumen reserves are differentiated from proved undeveloped bitumen reserves by the presence of drilled production/injection well pairs at the reserves estimation effective date. Because a steam plant has a long life relative to well pairs, in the early stages of a SAGD project, only a small portion of proved reserves will be developed as the number of well pairs drilled will be limited by the available steam capacity.

Recognition of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. Reserves will be classified as probable if the number of wells drilled falls between the stratigraphic well requirements for proved reserves and for probable reserves, or if the reserves are located outside of an approved development plan area, but within an approved project area. McDaniel's standard for probable reserves is a minimum of four stratigraphic wells per section. If reserves lie outside the approved development area, approval to include those reserves in the development area must be obtained before development drilling of SAGD well pairs can commence.

Development of the proved undeveloped reserves will take place in an orderly manner as additional well pairs are drilled to utilize the available steam when existing well pairs reach the end of their steam injection phase. The forecast production of Cenovus's proved bitumen reserves extends approximately 47 years, based on existing facilities. Production of the current proved developed portion is estimated to take approximately 13 years.

Crude Oil

Cenovus has a significant medium oil CO_2 EOR project at Weyburn and a significant heavy oil waterflood/polymer flood EOR project at Pelican Lake. These projects occur in large, well-developed reservoirs, where undeveloped reserves are not necessarily defined by the absence of drilling, but by anticipated improved recovery associated with development of the EOR schemes. Extending both EOR schemes within the projects requires intensive capital investment in infrastructure development and will occur over many years.

At Weyburn, investment in proved undeveloped reserves is projected to continue for over 40 years, with drilling of supplementary wells taking place over the next five years, and CO_2 flood advancement continuing many years beyond that. At Pelican Lake, investment in proved undeveloped reserves is projected to continue for three years, with a combination of infrastructure development, infill drilling and polymer flood advancement.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The evaluation of reserves is a continuous process that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly. For a discussion of the risk factors and uncertainties affecting reserves data, see "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates".

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following tables summarize Cenovus's interests in producing and non-producing wells, as at December 31, 2016:

	Oil		Gas		Total	
Producing Wells[1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	490	245	293	279	783	524
Conventional	1,923	1,907	24,128	23,952	26,051	25,859
Total Alberta	2,413	2,152	24,421	24,231	26,834	26,383
Saskatchewan	645	402	-	-	645	402
Total	3,058	2,554	24,421	24,231	27,479	26,785

(1) Includes wells containing multiple completions as follows: 22,082 gross gas wells (21,924 net wells) and 1,131 gross oil wells (1,013 net wells).

	Oil		Gas		Total	
Non-Producing Wells[1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	109	60	349	240	458	300
Conventional	929	909	1,085	1,051	2,014	1,960
Total Alberta	1,038	969	1,434	1,291	2,472	2,260
Saskatchewan	196	85	1	1	197	86
Total	1,234	1,054	1,435	1,292	2,669	2,346

(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells do not include other types of wells such as stratigraphic test wells, service wells, or wells that have been abandoned.

Cenovus has no material properties with attributed reserves which are capable of producing, but which are not on production.

Exploration and Development Activity

The following tables summarize Cenovus's gross participation and net interest in wells drilled in 2016[1]:

	Oil Sands		Conventional		Total	
Development Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	54	28	10	9	64	37
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	-	-	-	-
Total Canada	54	28	10	9	64	37

(1) Cenovus did not have any participation or interest in any exploration wells in 2016.

During the year ended December 31, 2016, Oil Sands drilled 205 gross stratigraphic test wells (103 net wells) and Conventional drilled 58 gross stratigraphic test wells (58 net wells).

During the year ended December 31, 2016, no service wells were drilled within Oil Sands or Conventional. SAGD well pairs are counted as a single producing well in the table above.

For all types of wells except stratigraphic test wells, the calculation of the number of wells is based on the number of surface locations. For stratigraphic test wells, the calculation is based on the number of bottomhole locations.

Development activities were focused on sustaining bitumen production at Foster Creek and Christina Lake, and on supporting our EOR projects at Pelican Lake and Weyburn.

Properties With No Attributed Reserves

Cenovus has approximately 3.9 million gross acres (3.4 million net acres) of properties in Canada to which no reserves have been specifically attributed. These properties are planned for current and future development in both the Corporation's oil sands and conventional oil and gas operations. There are currently no work commitments on these properties.

Cenovus has rights to explore, develop, and exploit approximately 81,000 net acres that could potentially expire by December 31, 2017, which relate entirely to Crown and freehold land.

For areas where Cenovus holds interests in different formations under the same surface area through separate leases, the Corporation has calculated its gross and net acreage on the basis of each individual lease.

Properties with no attributed reserves include Crown lands where bitumen contingent and prospective resources have been identified and Crown lands where exploration activities to date have not identified potential reserves in commercial quantities. See "Risk Factors – Financial Risks – Commodity Prices" and "Risk Factors – Financial Risks – Development and Operating Costs" and "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates" in this AIF for further discussion of economic and risk factors relevant to Cenovus's properties with no attributed reserves.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated total future abandonment and reclamation costs for existing wells, facilities, and infrastructure is based on Management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Cenovus's working interest and the estimated timing of the costs to be incurred in future periods. Cenovus has developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location.

Cenovus has estimated undiscounted future abandonment and reclamation costs for its existing upstream assets at approximately $6.14 billion (approximately $1.078 billion, discounted at 10 percent) at December 31, 2016, of which the Corporation expects to pay between $200 million and $240 million in the next three financial years on a portion of the 34,762 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Cenovus's proved reserves, approximately $9 billion has been deducted in estimating the FNR, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Tax Horizon

In 2017, Cenovus currently expects to incur losses for income tax purposes and recover income taxes paid in prior years. Tax may be payable by the Corporation in 2018.

Costs Incurred

($ millions)	2016
Acquisitions	
Unproved	11
Proved	-
Total Acquisitions	11
Exploration Costs	35
Development Costs	738
Total Costs Incurred	784

Forward Contracts

Cenovus may use financial derivatives to manage its exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in the notes to the Corporation's annual audited Consolidated Financial Statements for the year ended December 31, 2016.

Production Estimates

The following table summarizes the estimated 2017 average daily volume of Company Working Interest Before Royalties reflected in the reserves reports for all properties held on December 31, 2016 using forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of undeveloped reserves, and that there are no divestitures.

2017 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)(1)	176,481	184,513
Light and Medium Oil (bbls/d)	24,814	27,600
Heavy Oil (bbls/d)	25,747	26,812
Natural Gas (MMcf/d)	349	376
Natural Gas Liquids (bbls/d)	706	778
Company Working Interest Before Royalties (BOE/d)	285,952	302,444

(1) Includes Foster Creek production of 74,981 barrels per day for proved and 77,875 barrels per day for proved plus probable, and Christina Lake production of 101,500 barrels per day for proved and 106,638 barrels per day for proved plus probable.

Production History

Average Working Interest Daily Production Volumes - 2016

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	70,244	81,588	73,798	64,544	60,882
Christina Lake (Bitumen)	79,449	82,808	79,793	78,060	77,093
	149,693	164,396	153,591	142,604	137,975
Conventional Liquids					
Heavy Oil	29,185	28,913	28,096	28,500	31,247
Light and Medium Oil	25,844	25,016	25,280	26,127	26,970
Natural Gas Liquids(1)	1,064	1,176	1,073	798	1,206
Total Crude Oil and Natural Gas Liquids	205,786	219,501	208,040	198,029	197,398
Natural Gas (MMcf/d)					
Oil Sands	17	17	18	18	17
Conventional	377	362	374	381	391
Total Natural Gas	394	379	392	399	408
Total (BOE/d)	271,453	282,669	273,373	264,528	265,398

(1) Natural gas liquids include condensate volumes.

Average Royalty Interest Daily Production Volumes - 2016

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil	-	-	-	-	-
Light and Medium Oil	70	48	31	51	151
Natural Gas Liquids (1)	2	1	1	1	2
Total Crude Oil and Natural Gas Liquids	72	49	32	52	153
Natural Gas (MMcf/d)					
Conventional	-	-	-	-	-
Total (BOE/d)	72	49	32	52	153

(1) Natural gas liquids include condensate volumes.

Per-Unit Results

The following tables summarize Cenovus's per-unit results, as well as the impact of realized financial hedging, on a quarterly basis, before deduction of royalties, for the periods indicated:

Netbacks[1] – 2016 (excluding impact of realized gain (loss) on risk management)	Year	Q4	Q3	Q2	Q1
Bitumen - Foster Creek ($/bbl)					
Sales Price	30.32	38.59	33.61	33.40	11.82
Royalties	(0.01)	(0.27)	0.19	0.23	(0.16)
Transportation and blending	8.84	7.37	8.38	11.44	8.70
Operating expenses	10.55	10.60	9.63	10.15	12.05
Netback	10.94	20.89	15.41	11.58	(8.77)
Bitumen - Christina Lake ($/bbl)					
Sales Price	25.30	34.78	29.11	28.31	8.85
Royalties	0.33	0.56	0.41	0.28	0.05
Transportation and blending	4.68	4.08	4.49	4.90	5.28
Operating expenses	7.48	8.15	7.72	6.35	7.61
Netback	12.81	21.99	16.49	16.78	(4.09)
Total Bitumen ($/bbl)					
Sales Price	27.64	36.67	31.30	30.59	10.13
Royalties	0.17	0.14	0.30	0.26	(0.04)
Transportation and blending[3]	6.62	5.71	6.39	7.84	6.75
Operating expenses	8.91	9.37	8.65	8.06	9.52
Netback	11.94	21.45	15.96	14.43	(6.10)
Heavy Crude Oil ($/bbl)					
Sales Price	35.82	40.72	40.50	36.77	25.99
Royalties	3.31	4.08	3.97	3.95	1.40
Transportation and blending	4.60	4.90	4.86	3.85	4.77
Operating expenses	13.38	14.69	12.43	12.34	13.98
Production and mineral taxes	0.01	0.01	0.01	0.01	-
Netback	14.52	17.04	19.23	16.62	5.84

(1) Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Our calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation Handbook. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Netback does not have a standardized meaning as prescribed by IFRS and therefore is considered a non-GAAP measure. As such, it may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this AIF 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, and to comply with the requirements of NI 51-101. This measure 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 MD&A available at cenovus.com. For the reconciliation of the financial components of Netback to the GAAP measure and the sales volumes used in the calculations, see "Netback Reconciliations" in Appendix D.

Netbacks[1] – 2016

(excluding impact of realized gain (Loss) on risk management)	Year	Q4	Q3	Q2	Q1
Light and Medium Crude Oil ($/bbl)					
Sales Price	46.48	55.35	48.97	48.09	34.36
Royalties	9.28	14.87	8.91	8.52	5.18
Transportation and blending	2.73	2.69	2.71	2.77	2.73
Operating expenses	15.65	16.05	13.94	16.21	16.34
Production and mineral taxes	1.24	1.50	1.48	1.18	0.82
Netback	17.58	20.24	21.93	19.41	9.29
Total Bitumen and Crude Oil (Heavy, Light and Medium) ($/bbl)					
Sales Price	31.20	39.37	34.66	33.89	15.91
Royalties	1.77	2.38	1.83	1.93	0.90
Transportation and blending	5.84	5.25	5.74	6.56	5.89
Operating expenses	10.40	10.85	9.79	9.80	11.14
Production and mineral taxes	0.16	0.17	0.18	0.16	0.11
Netback	13.03	20.72	17.12	15.44	(2.13)
NGLs ($/bbl)					
Sales Price	31.16	40.79	29.71	28.11	24.99
Royalties	4.21	4.97	3.58	4.20	4.03
Netback	26.95	35.82	26.13	23.91	20.96
Total Bitumen, Crude Oil (Heavy, Light and Medium) and NGLs ($/bbl)					
Sales Price	31.20	39.38	34.64	33.87	15.97
Royalties	1.79	2.39	1.84	1.94	0.92
Transportation and blending	5.81	5.22	5.71	6.53	5.85
Operating expenses	10.35	10.80	9.74	9.76	11.08
Production and mineral taxes	0.16	0.17	0.18	0.16	0.11
Netback	13.09	20.80	17.17	15.48	(1.99)
Total Natural Gas ($/Mcf)					
Sales Price	2.32	2.99	2.49	1.53	2.31
Royalties	0.10	0.15	0.10	0.04	0.09
Transportation and blending	0.11	0.12	0.10	0.13	0.10
Operating expenses	1.15	1.25	1.05	1.06	1.23
Production and mineral taxes	-	-	0.01	-	-
Netback	0.96	1.47	1.23	0.30	0.89
Total ($/BOE)					
Sales Price	27.01	34.53	29.98	27.56	15.43
Royalties	1.49	2.06	1.55	1.51	0.82
Transportation and blending	4.56	4.20	4.51	5.07	4.51
Operating expenses	9.51	10.05	8.92	8.89	10.14
Production and mineral taxes	0.12	0.13	0.15	0.12	0.08
Netback	11.33	18.09	14.85	11.97	(0.12)

(1) Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Our calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation Handbook. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Netback does not have a standardized meaning as prescribed by IFRS and therefore is considered a non-GAAP measure. As such, it may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this AIF 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, and to comply with the requirements of NI 51-101. This measure 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 MD&A available at cenovus.com. For the reconciliation of the financial components of Netback to the GAAP measure and the sales volumes used in the calculations, see "Netback Reconciliations" in Appendix D.

Impact of Realized Gain (Loss) on Risk Management – 2016	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	3.23	0.91	2.14	1.97	8.16
Natural Gas ($/Mcf)	-	-	-	-	-
Total ($/BOE)	2.44	0.70	1.63	1.46	6.08

Capital Expenditures, Acquisitions and Divestitures

Cenovus has a large inventory of internal growth opportunities and continues to examine select acquisition opportunities to develop and expand its oil and gas properties. Acquisition opportunities may include corporate or asset acquisitions. Cenovus may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset divestitures or a combination of these sources.

In 2016, Cenovus had an active program to divest its non-core assets in order to increase its focus on key assets within the long-range business plan, as well as generate proceeds to partially fund its capital investment.

In the third quarter of 2015, Cenovus sold HRP, the holder of its royalty interest and mineral fee title lands business in Alberta, Saskatchewan and Manitoba to an unrelated third party for gross cash proceeds of $3.3 billion. Also in the third quarter of 2015, Cenovus acquired the Bruderheim rail terminal, a crude-by-rail terminal at Bruderheim, Alberta for $75 million plus adjustments.

The following table summarizes Cenovus's net capital investment for 2016 and 2015:

Net Capital Investment

($ millions)	**2016**	2015
Capital Investment		
Oil Sands		
Foster Creek	**263**	403
Christina Lake	**282**	647
Total	**545**	1,050
Other Oil Sands	**59**	135
	604	1,185
Conventional	**171**	244
Refining and Marketing	**220**	248
Corporate	**31**	37
Capital Investment	**1,026**	1,714
Acquisitions	**11**	87
Divestitures	**(8)**	(3,344)
Net Acquisition and Divestiture Activity	**3**	(3,257)
Net Capital Investment(1)	**1,029**	(1,543)

(1) *Includes expenditures on property, plant and equipment and exploration and evaluation assets.*

OTHER INFORMATION

COMPETITIVE CONDITIONS

All aspects of the oil and gas industry are highly competitive. Refer to "Risk Factors – Operational Risks – Competition" for further information on the competitive conditions affecting Cenovus.

ENVIRONMENTAL CONSIDERATIONS

Cenovus's operations are subject to laws and regulations concerning protection of the environment, pollution and the handling and transport of hazardous materials. These laws and regulations generally require the Corporation to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Safety, Environment and Responsibility Committee of the Corporation's Board reviews and recommends policies pertaining to corporate responsibility, including the environment, and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, have been designed to provide assurance that environmental and regulatory standards are met. Contingency plans have been put in place for a timely response to an environmental event and remediation/reclamation programs have been put in place and utilized to restore the environment.

Cenovus recognizes that there is a cost associated with carbon emissions and it believes that GHG regulations and the cost of carbon at various price levels can be adequately accounted for as part of business planning. As part of the Corporation's future planning, Management and the Board review the impact of a variety of carbon constrained scenarios on Cenovus's strategy. Although uncertainty remains regarding potential future emissions regulation, the Corporation will continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios. For a discussion of the risks associated with this uncertainty, see "Risk Factors – Environment & Regulatory Risks – Climate Change Regulation".

Cenovus also examines the impact of carbon regulation on its major projects, including its oil sands operations and its refining assets. Cenovus continues to closely monitor potential GHG legislation and litigation developments both in Canada and in the U.S.

Cenovus expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. Cenovus does not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2017. Refer to "Risk

Factors – Environment & Regulatory Risks – Environmental Regulations" for further information on environmental protection matters affecting Cenovus.

CORPORATE RESPONSIBILITY

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

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

EMPLOYEES

The following table summarizes Cenovus's full-time equivalent ("FTE") employees as at December 31, 2016:

	FTE Employees
Upstream	1,856
Downstream	126
Corporate	793
Total	2,775

Cenovus also engages a number of contractors and service providers. Refer to "Risk Factors - Operational Risks - Leadership and Talent" for further information on employee matters affecting Cenovus.

FOREIGN OPERATIONS

Cenovus, and its reportable segments, are not dependent upon foreign operations outside North America. As a result, the Corporation's exposure to risks and uncertainties in countries considered politically and economically unstable is limited. Any future operations outside North America may be adversely affected by changes in government policy, social instability or other political or economic developments which are not within Cenovus's control, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. Refer to "Risk Factors – Financial Risks – Foreign Exchange Rates" for information on foreign exchange rate matters affecting Cenovus.

DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The following individuals are directors of Cenovus.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Patrick D. Daniel[2,3,4] Calgary, Alberta, Canada	2009 Independent	Mr. Daniel is a director of Canadian Imperial Bank of Commerce; a director of Capital Power Corporation, a publicly traded North American power producer; and Chair of the North American Review Board of American Air Liquide Holdings, Inc., a subsidiary of a publicly traded industrial gases service company. Mr. Daniel served as a director of Enbridge Inc. ("Enbridge"), a publicly traded energy delivery company, from April 2000 to October 2012. During his tenure with Enbridge, he also served as President & Chief Executive Officer from January 2001 to February 2012 and as Chief Executive Officer from February 2012 to October 2012.
Ian W. Delaney[3,4,6] Toronto, Ontario, Canada	2009 Independent	Mr. Delaney is Chairman of The Westaim Corporation, a publicly traded investment company; and Chairman of Ontario Air Ambulance Services Co. (Ornge) a not-for-profit medical air and ground transportation organization. Mr. Delaney served as a director of Sherritt International Corporation ("Sherritt"), a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity, from October 1995 to May 2013. During his tenure with Sherritt, he also served as Chairman from November 1995 to May 2004, Executive Chairman from May 2004 to December 2008, Chairman and Chief Executive Officer from January 2009 to December 2011 and Chairman from January 2012 to May 2013. Mr. Delaney also served as Chairman of UrtheCast Corp. (formerly Longford Energy Inc.), a publicly traded video technology development company, from August 2012 to October 2013 and as a director of Dacha Strategic Metals Inc., a publicly traded investment company focused on the acquisition, storage and trading of strategic metals, from November 2012 to September 2014.
Brian C. Ferguson[7] Calgary, Alberta, Canada	2009	Mr. Ferguson has been President & Chief Executive Officer of Cenovus since its formation on November 30, 2009; and serves as a director of The Toronto-Dominion Bank. Mr. Ferguson is a Fellow of the Chartered Professional Accountants of Alberta and a member of the Chartered Professional Accountants of Canada.
Michael A. Grandin[4,8] Calgary, Alberta, Canada	2009 (Chair) Independent	Mr. Grandin is the Chair of Cenovus's Board. He is a director of HSBC Bank Canada and was a director of BNS Split Corp. II, a publicly traded investment company, from February 2005 until November 2016.
Steven F. Leer[2,4,5] Boca Grande, Florida, United States	2015 Independent	Mr. Leer is a lead director of Norfolk Southern Corporation, a publicly traded North American rail transportation provider; non-executive Chairman of the Board of USG Corporation ("USG"), a publicly traded manufacturer and distributor of high performance building systems; and a director of Parsons Corporation, a private engineering, construction, technical, and management services firm. Mr. Leer served as a director of USG from June 2005 to January 2012 and was lead director from January 2012 to November 2016. Mr. Leer also served as Chairman of Arch Coal, Inc. ("Arch Coal"), a publicly traded coal producing company, from April 2006 to April 2014 and served as a director of Arch Coal and its predecessor company from 1992. During his tenure with Arch Coal and its predecessor company, he also served as Chief Executive Officer from July 1992 to April 2012.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Richard J. Marcogliese[4,5,6] Alamo, California, United States	2016 Independent	Mr. Marcogliese is the Principal of iRefine, LLC, a privately owned petroleum refining consulting company; Executive Advisor of Pilko & Associates L.P., a private chemical and energy advisory company; and is presently engaged as an Operations Advisor to NTR Partners III LLC, a private investment company. He served as Operations Advisor to the CEO of Philadelphia Energy Solutions, a partnership between The Carlyle Group and a subsidiary of Energy Transfer Partners, L.P. that operates an oil refining complex on the U.S. Eastern seaboard, from September 2012 to January 2016.
Claude Mongeau[9] Montreal, Quebec, Canada	2016 Independent	Mr. Mongeau is a director of The Toronto-Dominion Bank. Mr. Mongeau served as a director of Canadian National Railway Company ("CN"), a publicly traded railroad and transportation company, from October 2009 to July 2016 and as President and Chief Executive Officer from January 2010 to June 2016. During his tenure with CN, he also served as Executive Vice-President and Chief Financial Officer from October 2000 until December 2009, and held various increasingly senior positions from the time he joined. Mr. Mongeau also served as a director of SNC-Lavalin Group Inc. from August 2003 to May 2015 and Chairman of the Board of the Railway Association of Canada.
Valerie A.A. Nielsen[3,4,6] Victoria, British Columbia, Canada	2009 Independent	Ms. Nielsen was a director of Wajax Corporation, a publicly traded industrial parts and service company, from June 1995 to May 2012.
Charles M. Rampacek[3,4,6] Dallas, Texas, United States	2009 Independent	Mr. Rampacek is a director of Energy Services Holdings, LLC, a private industrial services company that was formed in 2012 from the combination of Ardent Holdings, LLC and another company. Mr. Rampacek served as a director of Flowserve Corporation, a publicly traded manufacturer of industrial equipment from March 1998 to May 2016. He served as Chair of Ardent Holdings, LLC from December 2008 to July 2012. Mr. Rampacek also served as a director of Enterprise Products Holdings, LLC, the sole general partner of Enterprise Products Partners, L.P., a publicly traded midstream energy limited partnership, from November 2006 to September 2011; and Pilko & Associates L.P., a private chemical and energy advisory company, from September 2011 to February 2014.
Colin Taylor[2,4,5] Toronto, Ontario, Canada	2009 Independent	Mr. Taylor served two consecutive four-year terms as Chief Executive & Managing Partner of Deloitte LLP and then acted as Senior Counsel until his retirement in May 2008. Mr. Taylor is a Fellow of the Chartered Professional Accountants of Ontario and a member of the Chartered Professional Accountants of Canada.
Wayne G. Thomson[2,4,5] Calgary, Alberta, Canada	2009 Independent	Mr. Thomson is a director of TVI Pacific Inc., a publicly traded international mining company; Chairman of Maha Energy Inc., a public Swedish oil and gas company; Chairman and interim Executive Chairman of Inventys Thermal Technologies Inc., a private carbon capture technology company; and Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves. Mr. Thomson served as a Chief Executive Officer of Iskander Energy Corp., a private international oil and gas company, from November 2011 to August 2014 and as a director from November 2011 to March 2016.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Rhonda I. Zygocki[3,4,6] Friday Harbor, Washington, United States	2016 Independent	Ms. Zygocki served as Executive Vice President, Policy and Planning of Chevron Corporation ("Chevron"), an integrated energy company, from March 2011 until her retirement in February 2015 and prior thereto, during her 34 years with Chevron, she held a number of senior management and executive leadership positions in international operations, public affairs, strategic planning, policy, government affairs and health, environment and safety. She is a senior advisor with the Center for Strategic and International Studies and a former advisory board member of the Woodrow Wilson International Center of Scholars Canada Institute.

(1) Each of the directors first became members of Cenovus's Board pursuant to the Arrangement, with the following exceptions:

- *Mr. Leer who was elected as a director of Cenovus's Board at the Annual and Special Meeting of Shareholders held on April 29, 2015,*
- *Ms. Zygocki and Mr. Marcogliese who were elected as directors of Cenovus's Board at the Annual Meeting of Shareholders held on April 27, 2016, and*
- *Mr. Mongeau who was appointed as a director of Cenovus's Board as of December 1, 2016.*

The term of each of the directors is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

(2) Member of the Audit Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Nominating and Corporate Governance Committee.
(5) Member of the Reserves Committee.
(6) Member of the Safety, Environment and Responsibility Committee.
(7) As an officer and a non-independent director, Mr. Ferguson is not a member of any of the committees of Cenovus's Board.
(8) Ex-officio, by standing invitation, non-voting member of all other committees of Cenovus's Board. As an ex-officio non-voting member, Mr. Grandin attends as his schedule permits and may vote when necessary to achieve a quorum.
(9) Mr. Mongeau is not currently a member of any standing committees of the Board.

EXECUTIVE OFFICERS

The following individuals served as executive officers of Cenovus as at December 31, 2016.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Brian C. Ferguson Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Ferguson's biographical information is included under "Directors".
Ivor M. Ruste Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. Ruste has been Executive Vice-President & Chief Financial Officer of Cenovus since its formation on November 30, 2009.
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President, Oil Sands Development Mr. Chhina became Executive Vice-President, Oil Sands Development on September 1, 2015. From December 2010 to August 2015, Mr. Chhina was Cenovus's Executive Vice-President, Oil Sands. From November 2009 to November 2010, Mr. Chhina was Cenovus's Executive Vice-President, Enhanced Oil Development & New Resource Plays.
Judy A. Fairburn Calgary, Alberta, Canada	Executive Vice-President, Business Innovation Ms. Fairburn became Executive Vice-President, Business Innovation on December 1, 2015. From February 2013 to November 2015, Ms. Fairburn was Cenovus's Executive Advisor. From November 2009 to January 2013, Ms. Fairburn was Cenovus's Executive Vice-President, Environment & Strategic Planning.
Kieron McFadyen Calgary, Alberta, Canada	Executive Vice-President & President, Upstream Oil & Gas Mr. McFadyen became Executive Vice-President & President, Upstream Oil & Gas on April 6, 2016. From January 2012 to April 2016, Mr. McFadyen was Group Vice President, Non Operated Joint Ventures of Royal Dutch Shell plc, a multinational oil and gas company ("Royal Dutch Shell"), and from November 2006 to January 2012, he was Group and Executive Vice President (HSSE-SP) of Royal Dutch Shell.
Jacqueline (Jacqui) A.T. McGillivray Calgary, Alberta, Canada	Executive Vice-President, Safety & Organization Effectiveness Ms. McGillivray became Executive Vice-President, Safety & Organization Effectiveness on July 1, 2015. From October 2012 to June 2015, Ms. McGillivray was Cenovus's Senior Vice-President & Chief People Officer. From November 2010 to October 2012, Ms. McGillivray was Head of Global Human Resources at Talisman Energy Inc.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Robert W. Pease Calgary, Alberta, Canada	Executive Vice-President, Corporate Strategy & President, Downstream Mr. Pease became Executive Vice-President, Corporate Strategy & President, Downstream on July 1, 2015. From June 2014 to June 2015, Mr. Pease was Cenovus's Executive Vice-President, Markets, Products & Transportation. From February 2014 to May 2014, Mr. Pease was Vice President, Global Business Excellence, Supply & Trading of Shell Trading (US) Company, a corporation that acts as the market interface for Royal Dutch Shell companies and affiliates in the U.S.; and from November 2008 until January 2014, he was President and Chief Executive Officer of Motiva Enterprises LLC, a refiner, distributer and marketer of fuels in the eastern and Gulf Coast regions of the U.S.
Alan C. Reid Calgary, Alberta, Canada	Executive Vice-President, Environment, Corporate Affairs, Legal & General Counsel Mr. Reid became Executive Vice-President, Environment, Corporate Affairs, Legal & General Counsel on December 1, 2015. From September 2015 to November 2015, Mr. Reid was Cenovus's Executive Vice-President, Environment, Corporate Affairs & Legal. From January 2014 to August 2015, Mr. Reid was Cenovus's Senior Vice-President, Christina Lake & Narrows Lake. From January 2012 to January 2014, Mr. Reid was Cenovus's Senior Vice-President, Christina Lake. From November 2009 to January 2012, Mr. Reid was Cenovus's Vice-President, Regulatory, Health & Safety.
J. Drew Zieglgansberger Calgary, Alberta, Canada	Executive Vice-President, Oil Sands Manufacturing Mr. Zieglgansberger became Executive Vice-President, Oil Sands Manufacturing on September 1, 2015. From June 2015 to August 2015, Mr. Zieglgansberger was Cenovus's Executive Vice-President, Operations Shared Services. From June 2012 to May 2015, Mr. Zieglgansberger was Cenovus's Senior Vice-President, Operations Shared Services. From January 2012 to May 2012, Mr. Zieglgansberger was Cenovus's Senior Vice-President, Regulatory, Local Community & Military. From December 2010 to January 2012, Mr. Zieglgansberger was Cenovus's Senior Vice-President, Christina Lake.

As of December 31, 2016, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,143,169 common shares of Cenovus ("Common Shares") or approximately 0.13 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of Cenovus's directors and officers are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of Cenovus.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the Corporation's knowledge, none of its current directors or executive officers are, as at the date of this AIF, or have been, within 10 years prior to the date of this AIF, a director, chief executive officer or chief financial officer of any company that:

(a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (each, an "Order") and that was issued while that director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

To the Corporation's knowledge, other than as described below, none of its directors or executive officers:

(a) is, as at the date of this AIF, or has been within 10 years prior to the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within 10 years prior to the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer.

To the Corporation's knowledge, none of its directors or executive officers has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Mr. Delaney was a director of OPTI Canada Inc. ("OPTI") when it commenced proceedings for creditor protection under the *Companies' Creditors Arrangement Act* (Canada) ("CCAA") on July 13, 2011. Ernst & Young Inc. was appointed as monitor of OPTI. On November 28, 2011, OPTI announced that it had closed a transaction whereby a subsidiary of CNOOC Limited acquired all of the outstanding securities of OPTI pursuant to a plan of arrangement under the CCAA and the *Canada Business Corporations Act*.

Mr. Mongeau was, prior to August 10, 2009, a director of Nortel Networks Corporation and Nortel Networks Limited, each of which initiated creditor protection proceedings under the *Companies' Creditors Arrangement Act* (Canada) on January 14, 2009. Certain U.S. subsidiaries filed voluntary petitions in the United States under Chapter 11 of the U.S. Bankruptcy Code, and certain Europe, Middle East and Africa subsidiaries made consequential filings in Europe and the Middle East.

AUDIT COMMITTEE

The Audit Committee mandate is included as Appendix C to this AIF.

COMPOSITION OF THE AUDIT COMMITTEE

The Audit Committee consists of four members, each of whom is independent and financially literate in accordance with National Instrument 52-110 *Audit Committees*. The education and experience of each of the members of the Audit Committee relevant to the performance of the responsibilities as an Audit Committee member is outlined below.

Patrick D. Daniel

Mr. Daniel holds a Bachelor of Science (University of Alberta) and a Master of Science (University of British Columbia), both in chemical engineering. He also completed Harvard University's Advanced Management Program. He is a past Chief Executive Officer and director of Enbridge, a publicly traded energy delivery company. He is also a past director and member of the audit committee of Enerflex Systems Income Fund, a compression systems manufacturer, and a past director and Chair of the finance committee of Synenco Energy Inc., an oil sands mining company which was acquired by Total E&P Canada Ltd. in August 2008.

Steven F. Leer

Mr. Leer holds a Bachelor of Electrical Engineering (University of the Pacific) and a Master of Business Administration (Olin School of Business, Washington University). He was awarded an honorary doctorate by the University of the Pacific in May 1993. Mr. Leer is a lead director of Norfolk Southern Corporation, a publicly traded North American rail transportation provider; and a director of Parsons Corporation, a private engineering, construction, technical, and management services firm. Mr. Leer served as director of USG, a publicly traded manufacturer and distributor of high performance building systems, from June 2005 to January 2012 and as lead director of USG from January 2012 to November 2016. He was Chairman of Arch Coal, a publicly traded coal producing company, from April 2006 to April 2014 and served as a director of Arch Coal and its predecessor company from 1992. During his tenure with Arch Coal and its predecessor company he also served as Chief Executive Officer from July 1992 to April 2012 and President from July 1992 to April 2006. He was a member of the Board of Trustees of Washington University in St. Louis and is a former director of the Business Roundtable and the National Association of Manufacturers.

Colin Taylor
(Financial Expert and Audit Committee Chair)

Mr. Taylor is a chartered professional accountant, a Fellow of the Chartered Professional Accountants of Ontario and a member of the Chartered Professional Accountants of Canada. He also completed Harvard University's Advanced Management Program. Mr. Taylor served two consecutive four-year terms (June 1996 to May 2004) as Chief Executive and Managing Partner of Deloitte LLP and continued as Senior Counsel until his retirement in May 2008. He has held a number of international management and governance responsibilities throughout his professional career. Mr. Taylor also served as Advisory Partner to a number of public and private company clients of Deloitte LLP.

Wayne G. Thomson

Mr. Thomson holds a Bachelor of Science of Mechanical Engineering (University of Manitoba) and is a professional engineer. He is a director of TVI Pacific Inc., a publicly traded international mining company; Chairman of Maha Energy Inc., a public

Swedish oil and gas company; Chairman and interim Executive Chairman of Inventys Thermal Technologies Inc. He also serves as Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves, since 2005. Mr. Thomson served as Chief Executive Officer of Iskander Energy Corp ("Iskander") and as director of Iskander from November 2011 to March 2016.

The above list does not include Michael A. Grandin who is, by standing invitation, an ex-officio member of Cenovus's Audit Committee.

Pre-Approval Policies and Procedures

Cenovus has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The Audit Committee has established a budget for the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP, the Corporation's auditor. Subject to the Audit Committee's discretion, the budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee. The list of permitted services is sufficiently detailed to ensure that: (i) the Audit Committee knows precisely what services it is being asked to pre-approve; and (ii) it is not necessary for any member of Management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the following paragraph, the Audit Committee has delegated authority to the Chair of the Audit Committee (or if the Chair is unavailable, any other member of the Audit Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services ("Delegated Authority"). Any required determination about the Chair's unavailability will be required to be made by the good faith judgment of the applicable other member(s) of the Audit Committee after considering all facts and circumstances deemed by such member(s) to be relevant. All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full Audit Committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that has been pre-approved pursuant to Delegated Authority: (i) may not exceed $200,000, in the case of pre-approvals granted by the Chair of the Audit Committee; and (ii) may not exceed $50,000, in the case of pre-approvals granted by any other member of the Audit Committee.

All proposed services or the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the Audit Committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the Audit Committee or pursuant to Delegated Authority.

External Auditor Service Fees

The following table provides information about the fees billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP in the years ended December 31, 2016 and 2015:

($ thousands)	**2016**	2015
Audit Fees[(1)]	**2,793**	2,692
Audit-Related Fees[(2)]	**111**	482
Tax Fees[(3)]	**71**	99
All Other Fees[(4)]	**10**	-
Total	**2,985**	3,273

(1) Audit Fees consist of the aggregate fees billed for the audit of the Corporation's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit Fees. The services provided in this category included audit-related services in relation to Cenovus's prospectuses, systems development, controls testing and participation fees levied by the Canadian Public Accountability Board.

(3) Tax Fees consist of the aggregate fees billed for audit related fees, tax compliance, tax advice and tax planning.

(4) All Other Fees are related to a readiness assessment to satisfy Extractive Sector Transparency Measures Act reporting requirements.

DESCRIPTION OF CAPITAL STRUCTURE

The following is a summary of the rights, privileges, restrictions and conditions which are attached to Common Shares and Cenovus's first and second preferred shares (collectively, "Preferred Shares"). Cenovus is authorized to issue an unlimited number of Common Shares and First Preferred Shares and Second Preferred Shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding Common Shares. As at December 31, 2016, there were approximately 833.3 million Common Shares and no Preferred Shares outstanding.

COMMON SHARES

The holders of Common Shares are entitled: (i) to receive dividends if, as and when declared by Cenovus's Board; (ii) to receive notice of, to attend, and to vote on the basis of one vote per Common Share held, at all meetings of shareholders; and (iii) to participate in any distribution of the Corporation's assets in the event of liquidation, dissolution or winding up or other distribution of its assets among its shareholders for the purpose of winding up its affairs.

PREFERRED SHARES

Preferred Shares may be issued in one or more series. Cenovus's Board may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of Preferred Shares are not entitled to vote at any meeting of shareholders, but may be entitled to vote if the Corporation fails to pay dividends on that series of Preferred Shares. The First Preferred Shares are entitled to priority over the Second Preferred Shares and the Common Shares with respect to the payment of dividends and the distribution of assets in the event of any liquidation, dissolution or winding up of Cenovus's affairs. Pursuant to a special resolution of the shareholders of the Corporation passed at the annual and special meeting of the Corporation's shareholders on April 29, 2015, the Corporation's articles were amended to provide that the aggregate number of Preferred Shares issued by the Corporation may not exceed 20 percent of the aggregate number of Common Shares then outstanding.

SHAREHOLDER RIGHTS PLAN

Cenovus has a shareholder rights plan (the "Shareholder Rights Plan") that was adopted in 2009 to ensure, to the extent possible, that all its shareholders are treated fairly in connection with any take-over bid for Cenovus. The Shareholder Rights Plan creates a right that attaches to each issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited take-over bid, whereby a person acquires or attempts to acquire 20 percent or more of Cenovus's Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquirer, from and after the separation time (unless delayed by the Corporation's Board) and before certain expiration times, to acquire Common Shares at 50 percent of the market price at the time of exercise. The Shareholder Rights Plan was reconfirmed at the 2015 annual and special meeting of shareholders and must be reconfirmed by the Corporation's shareholders at every third annual shareholder meeting.

DIVIDEND REINVESTMENT PLAN

Cenovus has a dividend reinvestment plan which permits holders of Common Shares to automatically reinvest all or any portion of the cash dividends paid on their Common Shares in additional Common Shares. At the discretion of the Corporation, the additional Common Shares may be issued from treasury at the volume weighted average price of the Common Shares (denominated in the currency in which the Common Shares trade on the applicable stock exchange) traded on the Toronto Stock Exchange ("TSX") during the last five trading days preceding the relevant dividend payment date or purchased on the market.

EMPLOYEE STOCK OPTION PLAN

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise options to purchase Common Shares. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options granted prior to February 17, 2010 expired after five years, while options granted on or after February 17, 2010 expire after seven years. Each option granted prior to February 24, 2011 has an associated tandem stock appreciation right which gives the option holder the right to elect to receive a cash payment equal to the excess of the market price of the Common Shares at the time of exercise over the exercise price of the option in exchange for surrendering the option. Each option granted on or after February 24, 2011 has an associated net settlement right. In lieu of exercising the option, the net settlement right grants the option holder the right to receive the number of Common Shares that could be acquired with the excess value of the market price of the Common Shares at the time of exercise over the exercise price of the option.

RATINGS

The following information relating to Cenovus's credit ratings is provided as it relates to the Corporation's financing costs and liquidity. Specifically, credit ratings affect Cenovus's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on Cenovus's debt by the Corporation's rating agencies or a negative change in its ratings outlook could adversely affect Cenovus's cost of financing, its access to sources of liquidity and capital, and potentially obligate it to post incremental collateral in the form of cash, letters of credit or other financial instruments. See "Risk Factors" in this AIF for further information.

The following table outlines the current ratings and outlooks of Cenovus's debt:

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")
Senior Unsecured			
Long-Term Rating	BBB	Ba2	BBB (high)
Outlook/Trend	Stable	Stable	Stable

Credit ratings are intended to provide an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and, at any time, may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories. A S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. A "Stable" outlook indicates that a rating is not likely to change.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Ba2 by Moody's is within the fifth highest of nine categories and is assigned to debt securities which are considered speculative-grade and subject to substantial credit risk. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category. A designation of Stable indicates a low likelihood of a rating change over the medium term.

DBRS's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB (high) by DBRS is within the fourth highest of 10 categories and is assigned to debt securities considered to be of adequate credit quality. The capacity for payment of financial obligations is considered acceptable. Entities in the BBB category may be vulnerable to future events. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. Rating trends provide guidance in respect of DBRS' opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories - "Positive", "Stable" or "Negative". The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

Throughout the last two years, Cenovus has made payments to each of S&P, Moody's and DBRS related to the rating of the Corporation's debt. Additionally, Cenovus has purchased products and services from S&P and Moody's.

DIVIDENDS

The declaration of dividends is at the sole discretion of Cenovus's Board and is considered each quarter. Effective the first quarter of 2016, Cenovus reduced the quarterly dividend by 69 percent from $0.16 to $0.05 per Common Share. The Board has approved a first quarter dividend of $0.05 per share payable on March 31, 2017 to holders of Common Shares of record as of March 15, 2017. Readers should also refer to risk factors "Risk Factors – Financial Risks – Ability to Pay Dividends" for additional information.

Cenovus paid the following dividends over the last three years:

Dividends Paid ($ per share)	Year	Q4	Q3	Q2	Q1
2016	0.2000	0.0500	0.0500	0.0500	0.0500
2015	0.8524	0.1600	0.1600	0.2662	0.2662
2014	1.0648	0.2662	0.2662	0.2662	0.2662

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the TSX and the New York Stock Exchange ("NYSE") under the symbol CVE. The following table outlines the share price trading range and volume of shares traded by month in 2016:

	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
		($ per share)		(thousands)		(US$ per share)		(thousands)
January	18.15	15.71	17.26	108,176	12.82	10.76	12.29	58,904
February	17.19	12.70	15.48	105,528	12.44	9.10	11.42	66,848
March	18.14	15.39	16.90	93,522	13.97	11.41	13.00	49,865
April	20.11	16.12	19.89	83,386	16.07	12.25	15.84	45,076
May	20.52	18.30	19.77	70,938	15.80	14.11	15.08	43,105
June	21.00	16.92	17.87	88,827	16.56	12.90	13.82	41,919
July	18.93	17.23	18.69	67,412	14.52	13.11	14.30	41,757
August	20.06	17.68	18.95	54,907	15.72	13.47	14.45	31,370
September	19.84	17.15	18.83	76,582	15.35	12.93	14.37	40,938
October	21.39	18.33	19.35	72,319	15.96	13.96	14.44	40,029
November	21.26	17.96	20.77	69,538	15.82	13.36	15.46	33,592
December	22.07	20.18	20.30	70,528	16.82	14.96	15.13	36,665

RISK FACTORS

Cenovus's operations are exposed to a number of risks, some that impact the oil and gas industry as a whole and others that are unique to the Corporation's operations. The impact of any risk or a combination of risks may adversely affect, among other things, the Corporation's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict Cenovus's ability to pay a dividend to its shareholders and may materially affect the market price of its securities.

The Corporation's approach to risk management includes compliance with the Board approved Enterprise Risk Management Policy and the related enterprise risk management framework and program, as well as integration with Cenovus's Operations Management System. It includes an annual review of Cenovus's principal and emerging risks, an analysis of the severity and likelihood of each principal risk, consideration of the Corporation's current mitigation and an evaluation if additional mitigation or treatment of the risk is required. In addition, Cenovus continuously monitors its risk profile as well as industry best practices.

FINANCIAL RISKS

Financial risks include, but are not limited to: fluctuations in commodity prices; royalty regimes and tax laws; volatile capital markets; development and operating costs; availability of capital and access to sufficient liquidity; fluctuations in foreign exchange and interest rates; risks related to Cenovus's hedging activities; and risks related to the Corporation's ability to pay a dividend to shareholders. Changes in global economic conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, financial condition, results of operations and growth, the maintenance of Cenovus's existing operations, financial strength of the Corporation's counterparties, access to capital and cost of borrowing.

Commodity Prices

The Corporation's financial performance is significantly dependent on the prevailing prices of crude oil, natural gas and refined products. Crude oil prices are impacted by a number of factors including, but not limited to: the supply of and demand for crude oil; economic conditions; the actions of the Organization of Petroleum Exporting Countries ("OPEC") including, without limitation, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; government regulation; political stability; market access constraints and transportation interruptions (pipeline, marine or rail); the availability of alternate fuel sources; and weather conditions. Natural gas prices are impacted by a number of factors including, but not limited to: North American supply and demand; developments related to the market for liquefied natural gas; weather conditions; and prices of alternate sources of energy. Refined product prices are impacted by a number of factors including, but not limited to: global supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; and weather. All of these factors are beyond Cenovus's control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Cenovus's financial performance is also impacted by discounted or reduced commodity prices for its oil production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to international markets and the quality of oil produced. Of particular importance to Cenovus are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore trades at a discount to the market price for light and medium crude oil and heavy oil.

The financial performance of Cenovus's refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Margin volatility is impacted by numerous conditions including, but not limited to: fluctuations in the supply and demand for refined products; market competitiveness; crude oil costs; and weather. Refining margins are subject to seasonal factors as production changes to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on the Corporation's business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact the value of Cenovus's assets, the Corporation's ability to maintain its business and to fund growth projects including, but not limited to, the continued development of its oil sands properties. Prolonged periods of commodity price volatility may also negatively impact Cenovus's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial or extended decline in these commodity prices may result in a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production, unutilized long-term transportation commitments and/or low utilization levels at the Corporation's refineries.

Cenovus conducts an annual assessment of the carrying value of its assets in accordance with International Financial Reporting Standards. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Corporation's assets may be subject to impairment and the Corporation's net earnings could be adversely affected.

Development and Operating Costs

Cenovus's financial performance is significantly affected by the cost of developing and operating its assets. Development and operating costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; scheduling delays; failure to maintain quality construction and manufacturing standards; and supply chain disruptions, including access to skilled labour. Electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating costs that are susceptible to significant fluctuation.

Hedging Activities

Cenovus's Market Risk Mitigation Policy, which has been approved by the Board, allows Management to use derivative instruments to help mitigate the impact of changes in oil and natural gas prices, diluent or condensate supply prices and refining margins. Cenovus also uses derivative instruments in various operational markets to help optimize its supply cost or sales. The Corporation may also utilize derivative instruments to help mitigate the potential impact of changes in interest rates and foreign exchange rates.

The use of such hedging activities exposes the Corporation to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being not well correlated to the change in the valuation of the underlying exposures being hedged; deficiency in the Corporation's systems or controls; human error; and the unenforceability of Cenovus's contracts.

There is risk that the consequences of hedging to protect against unfavourable market conditions may limit the benefit to Cenovus of commodity price increases or changes in interest rates and foreign exchange rates. The Corporation may also suffer financial loss due to hedging arrangements if it is unable to produce oil, natural gas or refined products to fulfill its delivery obligations related to the underlying physical transaction.

Exposure to Counterparties

In the normal course of business, Cenovus enters into contractual relationships with suppliers, partners and other counterparties in the energy industry and other industries for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations, the Corporation may suffer financial losses, may have to delay its development plans or may have to forego other opportunities which may materially impact its financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of Cenovus's business may be dependent on its ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets, a sustained downturn in the prices of crude oil, refined products, natural gas, or significant unanticipated expenses related to development and maintenance of Cenovus's existing properties and facilities, and the associated credit impacts, may impede the Corporation's ability to secure and maintain cost-effective financing and limit its ability to achieve timely access to capital markets on acceptable terms and conditions. An inability to access capital could affect Cenovus's ability to make future capital expenditures and to meet all of its financial obligations as they come due. The Corporation's ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in its securities in particular.

As at December 31, 2016, Cenovus had US$4.75 billion in debt outstanding with no principal payments due until October 2019 (US$1.3 billion). The Corporation has a $4.0 billion committed credit facility, with a $1.0 billion tranche maturing on April 30, 2019 and a $3.0 billion tranche maturing on November 30, 2019. The entire amount of the committed credit facility was available at December 31, 2016, to meet operating and capital requirements. Going forward, an inability to access the capital markets, a sustained downturn in the prices of crude oil, refined products, natural gas or significant unanticipated expenses related to development and maintenance of Cenovus's existing properties and facilities could negatively impact the Corporation's liquidity, its credit ratings and its ability to access additional sources of capital. Cenovus is required to comply with various financial and operating covenants under its credit facilities and the indentures governing its debt securities. The Corporation routinely reviews the covenants and may make changes to its development plans, dividend policy, or may take alternative actions to ensure compliance. In the event that Cenovus does not comply with such covenants, its access to capital could be restricted or repayment could be accelerated.

Credit Ratings

The credit rating agencies regularly evaluate the Corporation and its long-term and short-term debt, and their ratings are based on the Corporation's financial strength and a number of factors not entirely within the Corporation's control, including conditions affecting the oil and gas industry generally, and the state of the economy. There can be no assurance that one or more of the Corporation's credit ratings will not be downgraded. A reduction in any of the Corporation's current credit ratings could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital.

Counterparties and suppliers are often interested in the Corporation's credit ratings when establishing and maintaining contractual business arrangements. The Corporation may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements, if one or more of its credit ratings falls below certain ratings floors. Additional collateral may be required due to further downgrades below certain ratings floors. Failure to provide adequate risk assurance to counterparties and suppliers may result in the Corporation foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may affect Cenovus's results as global prices for crude oil, natural gas and refined products are generally set in U.S. dollars, while many of the Corporation's operating and capital costs are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of the Corporation's oil, natural gas and refined products. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of the Corporation's oil, natural gas and refined products. In addition, Cenovus has chosen to borrow U.S. dollar long-term debt. A change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Cenovus's U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. Exchange rate fluctuations could have a material adverse effect on the Corporation's financial condition, results of operations and cash flows.

Interest Rates

The Corporation may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase Cenovus's net interest expense and affect how certain liabilities are recorded, both of which could negatively impact its financial results. Additionally, the Corporation is exposed to interest rates upon the refinancing of maturing long-term debt and anticipated future financing needs at prevailing interest rates.

Ability to Pay Dividends

The payment of dividends is at the discretion of the Board. All dividends will be reviewed by the Board and may be increased, reduced or suspended from time to time. Cenovus's ability to pay dividends and the actual amount of such dividends is dependent upon, among other things, the Corporation's financial performance, its debt covenants and obligations, its ability to meet its financial obligations as they come due, its working capital requirements, its future tax obligations, its future capital requirements, commodity prices and the risk factors set forth in this AIF.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

OPERATIONAL RISKS

Operational risks are those risks that affect the Corporation's ability to continue operations in the ordinary course of business. In general, Cenovus's operations are subject to general risks affecting the oil and gas industry. The Corporation's operational risks include, but are not limited to: operational and safety considerations; market access constraints and transportation interruptions (pipeline, marine or rail); phased growth execution; uncertainty of reserves and resources estimates; reservoir performance and technical challenges; partner risks; competition; technology limitations; third party claims; land claims; leadership and talent gaps; and information system failures.

Health and Safety

The operation of Cenovus's properties is subject to hazards of finding, recovering, transporting and processing hydrocarbons including, but not limited to: blowouts; fires; explosions; railcar incident or derailment; gaseous leaks; migration of harmful substances; oil spills; corrosion; acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. Any of these hazards can interrupt operations, impact the Corporation's reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, and cause environmental damage that may include polluting water, land or air.

Market Access Constraints and Transportation Interruptions

Cenovus's production is transported through various pipelines and its refineries are reliant on various pipelines to receive feedstock. Disruptions in, or restricted availability of, pipeline service and/or marine or rail transport, could adversely affect the Corporation's crude oil and natural gas sales, projected production growth, refining operations and its cash flows.

Interruptions or restrictions in the availability of these pipeline systems may limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for Cenovus's products. These interruptions and restrictions may be caused by the inability of the pipeline to operate, or they may be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects, which would result in extra long-term takeaway capacity, will be made by applicable third party pipeline providers or that any applications to expand capacity will receive the required regulatory approval, or that any such approvals will result in the construction of the pipeline project. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail, marine transport and other alternative types of transportation for the Corporation's production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, Cenovus's crude-by-rail and marine shipments may be impacted by service delays, inclement weather, railcar derailment or other rail or marine transport incidents and could adversely impact its crude oil sales volumes or the price received for its product or impact the Corporation's reputation or result in legal liability, loss of life or personal injury, loss of equipment or property, or environmental damage. In addition, new regulations, which will be phased in over time until 2025, will require tank cars used to transport crude oil to be replaced with newer, safer tank cars, or to be retrofitted to meet the same standards. The costs of complying with the new standards, or any further revised standards, will likely be passed on to rail shippers and may adversely affect Cenovus's ability to transport crude-by-rail or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of the Corporation's refinery customers may limit Cenovus's ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

The Corporation's crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; explosions; blowouts; power outages; migration of harmful substances into water systems; oil spills; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; equipment failures and other accidents; adverse weather conditions; pollution; and other environmental risks.

Producing and refining oil requires high levels of investment and involves particular risks and uncertainties. Cenovus's oil operations are susceptible to loss of production, slowdowns, shutdowns, or restrictions on the Corporation's ability to produce higher value products due to the interdependence of its component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

Cenovus's refining and marketing business is subject to all of the risks inherent in the operation of refineries, terminals, pipelines and other transportation and distribution facilities including, but not limited to: loss of product; failure to follow operating procedures or operate within established operating parameters; slowdowns due to equipment failure or transportation disruptions; railcar incidents or derailments; marine transport incidents; weather; fires and/or explosions; unavailability of feedstock; and price and quality of feedstock.

The Corporation does not insure against all potential occurrences and disruptions and it cannot be guaranteed that its insurance will be sufficient to cover any such occurrences or disruptions. Cenovus's operations could also be interrupted by natural disasters or other events beyond its control.

Uncertainty of Reserves and Future Net Revenue Estimates

The reserves estimates included in this AIF are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Corporation's control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may vary considerably from actual results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of FNR expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Cenovus's actual production, revenues, taxes and development and operating expenditures with respect to its reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Cenovus's business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Project Execution

There are risks associated with the execution and operation of the Corporation's upstream growth and development projects. These risks include, but are not limited to: Cenovus's ability to obtain the necessary environmental and regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; risk related to the accuracy of project cost estimates; ability to finance growth; ability to source or complete strategic transactions; and the effect of changing government regulation and public expectations in relation to the impact of oil sands and conventional development on the environment. The commissioning and integration of new facilities within the Corporation's existing asset base could cause delays in achieving targets and objectives. Failure to manage these risks could have a material adverse effect on Cenovus's financial condition, results of operations and cash flows.

Partner Risks

Some of the Corporation's assets are not operated by Cenovus or are held in partnership with others. Therefore, the Corporation's results of operations may be affected by the actions of third party operators or partners.

Interests in certain of the Corporation's upstream assets are held in a partnership with ConocoPhillips, an unrelated U.S. public company, and are operated by Cenovus. The Corporation's refining assets are held in a partnership with Phillips 66, an unrelated U.S. public company, and operated by Phillips 66. The success of Cenovus's refining operations is dependent on the ability of Phillips 66 to successfully operate this business and maintain the refining assets. The Corporation relies on the judgment and operating expertise of Phillips 66 in respect of the operation of such refining assets and Cenovus also relies on Phillips 66 to provide information on the status of such refining assets and related results of operations.

ConocoPhillips or Phillips 66, as unrelated third parties, may have objectives and interests that do not align with or may conflict with the Corporation's interests. Major capital decisions affecting these upstream and refining assets require agreement between each respective partner, while certain operational decisions may be made by the operator of the applicable assets. While Cenovus and its partners generally seek consensus with respect to major decisions concerning the direction and operation of these upstream and refining assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be satisfactorily met or met in a timely manner or at all. Unmet demands or expectations by either party or demands and expectations which are not satisfactorily met may affect Cenovus's participation in the operation of such assets, the Corporation's ability to obtain or maintain necessary licences or approvals or affect the timing of undertaking various activities.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of petroleum products. Cenovus competes with other producers and refiners, some of which may have lower operating costs or greater resources than the Corporation does. Competing producers may develop and implement recovery techniques and technologies which are superior to those Cenovus employs. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

Companies may announce plans to enter the oil sands business, to begin production or to expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of crude oil in the marketplace which may decrease the market price of crude oil, constrain transportation and increase the Corporation's input costs for and constrain the supply of skilled labour and materials.

Technology

Current SAGD technologies for the recovery of bitumen are energy intensive, requiring significant consumption of natural gas in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on Cenovus's business, financial condition, results of operations and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Litigation

From time to time, the Corporation may be the subject of litigation arising out of its operations. Claims under such litigation may be material or may be indeterminate. Various types of claims may be made including, without limitation, environmental damages, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement and employment matters. The outcome of such litigation is uncertain and may materially impact Cenovus's financial condition or results of operations. Moreover, unfavorable outcomes or settlements of litigation could encourage the commencement of additional litigation. Cenovus may also be subject to adverse publicity associated with such matters, regardless of whether Cenovus is ultimately found responsible. The Corporation may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Land Claims

In western Canada, Aboriginal groups have historically filed claims in respect of their Aboriginal rights and treaty rights against the governments of Canada and Alberta, and other government bodies, which may affect Cenovus's business. In particular, Aboriginal groups have claimed Aboriginal title and rights to a substantial portion of western Canada. In 2014, the Supreme Court of Canada granted Aboriginal title over non-treaty lands, representing the first occurrence of such a declaration. There exist outstanding Aboriginal and treaty rights claims, which may include Aboriginal title claims, on lands where Cenovus operates. Such claims have the potential to have an adverse effect on operations in affected areas. No certainty exists that any lands currently unaffected by claims brought by Aboriginal groups will remain unaffected by future claims. Recent outcomes of litigation concerning Aboriginal rights may result in increased claims and litigation activity in the future.

In May 2016, Canada announced its support for the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). The principles and objectives of UNDRIP have also been endorsed by the Government of Alberta. The means of implementation of UNDRIP by government bodies are uncertain and may include an increase in consultation obligations and processes associated with project development, posing risks and creating uncertainty with respect to project regulatory approval timelines and requirements.

Leadership and Talent

Cenovus's success in executing its business strategy is dependent upon Management's ability to source, develop and retain the required competencies to support current and future operations. Failure to attract and retain critical talent with the necessary leadership, professional and technical competencies, could have a material adverse effect on Cenovus's results of operations, pace of growth and financial condition.

Information Systems

Cenovus relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on Cenovus's business, financial condition, results of operations and cash flows.

In the ordinary course of business, Cenovus collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of Cenovus's employees and third parties. Despite Cenovus's security measures, Cenovus's information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on Cenovus's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to Cenovus's operations and damage to Cenovus's reputation, which could have a material adverse effect on Cenovus's business, financial condition, results of operations and cash flows.

ENVIRONMENTAL & REGULATORY RISKS

Cenovus's industry and its operations are subject to regulation and intervention under federal, provincial, territorial, state and municipal legislation in Canada and the U.S. in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; protection of certain species or lands; provincial and federal land use designations; the reduction of GHGs and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail or marine transport; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production); and/or facilities and possibly expropriation or cancellation of contract rights. Changes to government regulation could impact Cenovus's existing and planned projects or increase capital investment or operating expenses, adversely impacting the Corporation's financial condition, results of operations and cash flows.

Regulatory Approvals

Cenovus's operations require it to obtain approvals from various regulatory authorities and there are no guarantees that it will be able to obtain all necessary licences, permits and other approvals that may be required to carry out certain exploration and development activities on its properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Aboriginal consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

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

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

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

Because of Redwater and the current economic environment, the number of orphaned wells in Alberta has increased significantly and, accordingly, the aggregate value of the A&R liabilities assumed by the OWA has increased and may continue to increase. The OWA may seek funding for such liabilities from industry participants, including Cenovus through an increase in its annual levy, further changes to regulations or other means. While the impact on Cenovus of any legislative, regulatory or policy decisions as a result of the Redwater decision and its pending appeal cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, Cenovus's business, financial condition, results of operations and cash flows.

Royalty Regimes

The Corporation's cash flows may be directly affected by changes to royalty regimes. The governments of Alberta and Saskatchewan receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights. Government regulation of Crown royalties is subject to change for a number of reasons, including, among other things, political factors. Royalties are typically calculated based on benchmark prices, productivity per well, location, date of discovery, recovery method, well depth and the nature and quality of petroleum product produced. There is also a mineral tax in each province levied on hydrocarbon production from lands in which the Crown does not own the mineral rights. The potential for changes in the royalty and mineral tax regimes applicable in the provinces in which Cenovus operates creates uncertainty relating to the ability to accurately estimate future Crown burdens.

Alberta Royalty Review

On January 1, 2017, the Government of Alberta implemented a modernized royalty framework (the "Modernized Framework") based on recommendations of the Royalty Review Advisory Panel. The Modernized Framework will apply to all conventional wells spud on or after January 1, 2017. The Modernized Framework does not apply to oil sands production, which has its own separate royalty framework. Wells spud prior to July 13, 2016 will continue to operate under the previous royalty framework (the "Old Framework"). Wells spud between such dates may elect to opt-in to the Modernized Framework if certain criteria are met. After December 31, 2026, all wells will be subject to the Modernized Framework.

Under the Modernized Framework, royalties are determined on a "revenue-minus-costs" basis, with the cost component based on a drilling and completion cost allowance formula for each well, which is dependent on the vertical depth, horizontal length of the well and proppant placed. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Department of Energy ("ADOE") on an annual basis. The cost component attempts to incentivize innovation to reduce costs by allowing wells that operate under the average cost to remain at a lower rate of royalty even after recovering actual costs. Producers pay a flat royalty rate of five percent of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative revenues from the well equals the drilling and completion cost allowance for the well set by the ADOE. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate will be adjusted downward as the mature well's production declines, to a minimum of five percent. The drilling and completion cost allowance formula, post-payout royalty rates and production thresholds for mature wells came into effect on January 1, 2017.

As part of the Modernized Framework, the Alberta government announced two new strategic royalty programs to encourage oil and gas producers to boost production and explore resources in new areas: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs will take into account the higher costs associated with development of emerging resources and enhanced recovery methods when calculating royalty rates.

The royalty structure and rates for oil sands production in Alberta remain generally unchanged following the royalty review. The Government of Alberta has indicated that it plans to modernize the process of calculating costs and collecting oil sands royalties, and to improve disclosure of cost, revenue and collection information relating to oil sands projects and royalties.

Further changes to any of the royalty regimes in Alberta, changes to the existing royalty regime in Saskatchewan, changes to how existing royalty regimes are interpreted and applied by the applicable governments, or an increase in disclosure obligations for the Corporation could have a significant impact on the Corporation's financial condition, results of operations and cash flows. An increase in the royalty rates in either of Alberta or Saskatchewan would reduce the Corporation's earnings and could make, in the respective province, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of the Corporation's associated assets.

Tax Laws

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

United States Tax Risk

In November 2016, the U.S. elected a new Republican president. The Republicans control both the U.S. House of Representatives and the U.S. Senate. The new administration is reported to be considering comprehensive U.S. tax reform that could have a significant impact on Cenovus's financial condition or results from operations, however any impact is not presently quantifiable.

Environmental Regulations

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian and U.S. federal, provincial, territorial, state and municipal laws and regulations (collectively, environmental regulations). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with the Corporation's operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances in the environment. They also impose restrictions, liabilities and obligations in connection with the management of water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations can require significant expenditures, including costs and damages arising from releases or contaminated properties or spills, or from new compliance obligations. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. Failure to comply with environmental regulations may result in the imposition of fines, penalties and environmental protection orders. The costs of complying with environmental regulation may have a material adverse effect on Cenovus's financial condition, results of operations and cash flows. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase compliance costs, and have an adverse impact on the Corporation's operations.

Failure to comply with environmental regulations could have an adverse impact on Cenovus's reputation. There is also risk that Cenovus could face litigation initiated by third parties relating to climate change or other environmental regulations.

Climate Change Regulation

Various federal, provincial and state governments have announced intentions to regulate GHG emissions and other air pollutants. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation in the U.S. and Canada. Uncertainties exist relating to the timing and effects of these regulations. Additionally, lack of certainty regarding how any future federal legislation will harmonize with provincial or state regulations makes it difficult to accurately determine the cost estimate of climate change legislation compliance with certainty, including the effects of compliance with such initiatives on the Corporation's suppliers and service providers.

Alberta Climate Leadership Plan

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

The CLA and the CL Regulation impose registration, payment, remittance, reporting and administrative obligations on applicable persons throughout the fuel supply chain. The application of the carbon levy depends on the type and quantity of fuel purchased or produced and how such fuel is used by the purchaser. Under the CLA and CL Regulations, facilities subject to the *Specified Gas Emitters Regulation* (Alberta) (the "SGER") (which includes Cenovus's operating oil sands assets) are exempt from the carbon levy. Activities integral to oil and gas production processes are exempt until 2023. At this time, the determination of what constitutes an activity that is "integral" to conventional oil and gas production is still being clarified with the Alberta government. We expect the Corporation's operations to have minimal direct carbon levy exposure until 2023. It is not known what will occur in 2023 when the current exemptions are expected to end.

The Corporation is subject to the SGER, which requires owners of facilities that emit 100,000 tonnes per year or more of GHG to reduce the facility's emissions intensity by 20 percent below an average baseline of the facility's historic emissions performance. Owners may meet the reduction requirements in one of four ways: (1) physically abating emissions intensity at their facilities; (2) purchasing or using Alberta-based emission offset credits; (3) purchasing or using emission performance credits, which are credits generated by facilities that have emissions below the SGER requirements; or (4) purchasing technology offset credits by contributing to Emissions Reduction Alberta at a price of $30 per tonne. Facility owners must submit SGER compliance reports to Alberta Environment and Parks on March 31 of each year. Beginning in 2018, facilities subject to the SGER will transition from a historic emissions performance baseline to an output-based allocation approach.

In addition to GHG emissions pricing, the Climate Leadership Plan sets forth two additional components relevant to the oil and gas sector: (1) limiting oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (2) reducing methane emissions from oil and gas activities by 45 percent by 2025.

Additional changes to provincial climate change legislation may adversely affect for the Corporation's business, financial condition, results of operations and cash flows which cannot be reliably or accurately estimated at this time.

Federal Carbon Strategy

In October 2016, Canada ratified the Paris Agreement on climate change that was signed by Canada and over 160 other nations at the United Nations Framework Convention on Climate Change in December of 2015. Though the specific details of how Canada will accomplish the goals set out in the Paris Agreement have not yet been announced, in October 2016 the federal government announced a new national carbon pricing regime (the "Carbon Strategy") that will support the objectives of the Paris Agreement. Under the Carbon Strategy, all provinces will be required to adopt a carbon pricing scheme that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. If the provinces do not adopt such a scheme, a federal regime will be imposed upon them and the funds will be transferred back to the provincial government of the jurisdiction from where they were collected. Alternatively, provinces will be given the opportunity to implement a cap-and-trade system, but will need to demonstrate that the province's emissions are consistent with both Canada's national target and the results of the provinces who have implemented the carbon pricing scheme.

On December 9, 2016, all of the provinces and territories except for Saskatchewan and Manitoba signed the pan-Canadian framework to implement the Carbon Strategy. Further legislation and regulation is expected from the provinces in order to comply with the Carbon Strategy's requirements. For those provinces, including Alberta, which have already established a carbon tax or a cap and trade regime, or both, the national price on carbon will likely have little additional impact in the short term. None of the provinces have yet announced how they intend to comply with the long-term carbon pricing requirements. It is unclear how the Carbon Strategy will be implemented in Saskatchewan and Manitoba.

Adverse impacts to Cenovus's business as a result of comprehensive GHG legislation or regulation, including the CLA and the Carbon Strategy applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances adding costs to the products Cenovus produces; and reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus.

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

Low Carbon Fuel Standards

Existing and proposed environmental legislation developed by certain U.S. states, Canadian provinces, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue. The potential regulation may negatively affect the marketing of Cenovus's bitumen, crude oil or refined products, and may require the Corporation to purchase emissions credits in order to affect sales in such jurisdictions.

The state of California has implemented climate change regulation in the form of a Low Carbon Fuel Standard that requires the reduction of life cycle carbon emissions from transportation fuels. As an oil sands producer, Cenovus is not directly regulated and is not expected to have a compliance obligation. Refiners in California are required to comply with the legislation.

Renewable Fuel Standards

Cenovus's U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. Of specific note is the *Energy Independence and Security Act of 2007* ("EISA 2007") that established energy management goals and requirements. Pursuant to EISA 2007, among other things, the Environmental Protection Agency issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and requires renewable fuels such as ethanol and advanced biofuels to be blended with gasoline by the obligated party. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not blend renewable fuels into their finished products, they must purchase credits, referred to as Renewable Identification Numbers ("RINs"), in the open market. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the U.S. RIN numbers were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

The Corporation's refineries do not blend renewable fuels into the motor fuel products they produce and, consequently, Cenovus through WRB is obligated to purchase RINs in the open market, where prices fluctuate. In the future, the regulations could change the volume of renewable fuels required to be blended with refined products, creating volatility in the price for RINs or an insufficient number of RINs being available in order to meet the requirements. The Corporation's financial condition, results of operations, and cash flows may be materially adversely impacted as a result.

Alberta's Land-Use Framework

Alberta's Land-Use Framework has been implemented under the *Alberta Land Stewardship Act* ("ALSA") which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. In some cases, ALSA amends or extinguishes previously issued consents such as regulatory permits, licences, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta implemented the Lower Athabasca Regional Plan ("LARP") on September 1, 2012, which was issued under the ALSA. The LARP identifies legally-binding management frameworks, including for air, land and water, that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Cenovus received financial compensation from the Government of Alberta related to some of its non-core oil sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on the Corporation's business plan, its current operations at Foster Creek and Christina Lake, or on any of its filed applications. Uncertainty exists with respect to the impact to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation.

The Government of Alberta has also implemented the South Saskatchewan Regional Plan ("SSRP"), the second and similar regional plan to be developed under the ALSA. This plan applies to Cenovus's conventional oil and gas operations in southern Alberta. To date, the SSRP is not expected to materially impact Cenovus's existing conventional oil and gas operations, but no assurance can be given that future expansion of these operations will not be affected.

The Government of Alberta has completed the Phase I consultation on the North Saskatchewan Regional Plan ("NSRP"), and the regional planning process has commenced. This plan will apply to Cenovus's operations in central Alberta. No assurance can be given that the NSRP, or any future regional plans developed and implemented by the Government of Alberta, will not materially impact operations or future operations in this region.

The Government of Alberta has also announced four additional regional plans under ALSA which may apply to Cenovus's landholdings and operations in other areas of Alberta, but development of these plans has not yet begun.

Species at Risk Act

The Canadian federal legislation, *Species at Risk Act,* and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development in areas identified as critical habitat for species of concern (e.g. woodland caribou). Recent litigation against the federal government in relation to the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may modify the Corporation's pace and amount of development. If action and range plans developed by the Province are deemed not to provide sufficient likelihood of caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations.

Federal Air Quality Management System

The Multi-sector Air Pollutants Regulations ("MAPR"), issued under the *Canadian Environmental Protection Act, 1999*, seek to protect the environment and health of Canadians by setting mandatory, nationally-consistent air pollutant emission standards. The MAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from the Corporation's non-utility boilers, heaters and reciprocating engines are regulated in accordance with specified performance standards. Cenovus does not anticipate a material impact to existing or future operations as a result of the MAPR.

Federal Review of Environmental and Regulatory Processes

In 2016, the Government of Canada commenced a review of environmental and regulatory processes under various acts and is scheduled to release various reports in 2017 for public comment. Legislative, regulatory or policy changes may follow the public comment period.

The extent and magnitude of any adverse impacts of changes to the legislation or programs on project development and operations cannot be reliably or accurately estimated at this time as uncertainty exists with respect to recommendations being considered. Increased environmental assessment obligations may create risk of increased costs and project development delays.

Water Licences

Cenovus currently utilizes fresh water in certain operations, which is obtained under licences issued pursuant to the *Water Act* (Alberta) to provide, for example, domestic and utility water at the Corporation's SAGD facilities and for its bitumen delineation programs. Currently, the Corporation is not required to pay for the water it uses under these licences. If a change under these licences reduces the amount of water available for the Corporation's use, its production could decline or operating expenses could increase, both of which may have a material adverse effect on the Corporation's business and financial performance. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that Cenovus will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the Corporation's projects rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted on terms favourable to Cenovus, or at all, or that such additional water will in fact be available to divert under such licences.

Alberta Wetland Policy

Wetland management within Alberta is regulated by section 36 of the *Water Act,* together with the Alberta Wetland Policy and the Provincial Wetland Restoration and Compensation Guide. Before undertaking an activity within a wetland, approval must be obtained in accordance with the *Water Act* and the *Water Ministerial Regulation*.

Pursuant to the Alberta Wetland Policy, developers of oil and gas assets in wetlands areas may be required to avoid the wetlands or mitigate the development's effects on wetlands. The Alberta Wetland Policy categorizes wetlands based on environmental value, and wetlands with the highest environmental value require the greatest efforts on behalf of proponents to avoid developmental impacts. Proponents must complete a wetland assessment and impact report and utilize the Alberta Wetland Mitigation Directive to mitigate impacts to wetlands from any activities they are proposing.

The Alberta Wetland Policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, where the Corporation's 10 year wetlands mitigation and monitoring plans were approved under the previous wetland policy.

New project developments and future phase expansions will likely be affected by aspects of this policy. Cenovus's oil sands leases are in areas where wetlands cover over 50 percent of the landscape. 'Avoidance' may not be an option for new projects, developments and phase expansions. Cenovus expects to be required to comply with requirements for wetland reclamation or, where permanent wetland loss will occur, wetland replacement. In accordance with the Alberta Wetland Restoration Directive, 2016, mechanisms for restorative replacement include purchase of credits (under development), payment to an in-lieu fee program, or permittee-responsible replacement action.

Based on written statements in the Alberta Wetland Mitigation Directive, 2016 and consultation with Alberta Environment and Parks (AEP) as well as the AER, Cenovus does not anticipate a material impact; however, with the change in the provincial government and the involvement of multiple agencies it is unclear how this policy will be implemented. At this time, no assurance can be given that the policy will not have an impact on future development plans.

REPUTATION RISKS

Cenovus relies on its reputation to build and maintain positive relationships with its stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions the Corporation takes that cause negative public opinion have the potential to negatively impact Cenovus's reputation which may adversely affect its share price, its development plans and its ability to continue operations.

Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention in recent public commentary on the subjects of environmental impact, climate change and GHG emissions. Despite that much of the focus is on bitumen mining operations and not in-situ production, public concerns about oil sands generally and GHG emissions and water and land use practices in oil sands developments specifically may, directly or indirectly, impair the profitability of the Corporation's current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertain economic modeling of current and future projects and delays relating to the sanctioning of future projects.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

OTHER RISK FACTORS

Arrangement Related Risk

Cenovus has certain post-Arrangement indemnification and other obligations under each of the arrangement agreement (the "Arrangement Agreement") and the separation and transition agreement (the "Separation Agreement"), both of which are among Encana, 7050372 and Subco, dated October 20, 2009 and November 30, 2009 respectively, entered in connection with the Arrangement. Encana and Cenovus have agreed to indemnify each other for certain liabilities and obligations associated with, among other things, in the case of Encana's indemnity, the business and assets retained by Encana, and in the case of Cenovus's indemnity, the Cenovus business and assets. At the present time, the Corporation cannot determine whether it will have to indemnify Encana for any substantial obligations under the terms of the Arrangement. Cenovus also cannot assure that if Encana has to indemnify Cenovus and its affiliates for any substantial obligations, Encana will be able to satisfy such obligations.

A discussion of additional risks, should they arise after the date of this AIF, which may impact Cenovus's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, can be found in the Corporation's most recent MD&A, available at sedar.com, sec.gov and cenovus.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2016, there were no legal proceedings to which Cenovus is or was a party, or that any of its property is or was the subject of, which involves a claim for damages in an amount, exclusive of interest and costs, that exceeds 10 percent of Cenovus's current assets and it is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2016, there were no penalties or sanctions imposed against Cenovus by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and it has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Corporation's directors or executive officers or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than ten percent of any class or series of Cenovus's outstanding voting securities, of which there are none that the Corporation is aware, or any associate or affiliate of any of the foregoing persons or companies, in each case, as at the date of this AIF, has or has had any material interest, direct or indirect, in any past transaction within the three most recently completed financial years or any proposed transaction that has materially affected or is reasonably expected to materially affect Cenovus.

MATERIAL CONTRACTS

During the year ended December 31, 2016, Cenovus has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into in the ordinary course of business and each of the Arrangement Agreement and the Separation Agreement, as described under "Risk Factors – Other Risk Factors – Arrangement Related Risk".

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 15, 2017 in respect of Cenovus's Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2016 and December 31, 2015 and the Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2016, 2015, and 2014 and Cenovus's internal control over financial reporting as at December 31, 2016. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Code of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules of the SEC.

Information relating to reserves in this AIF has been calculated by GLJ and McDaniel as independent qualified reserves evaluators. The principals of each of GLJ and McDaniel, in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of the Corporation's securities.

TRANSFER AGENTS AND REGISTRARS

In Canada:
Computershare Investor Services Inc.
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
Canada

In the United States:
Computershare Trust Company NA
250 Royall St.
Canton, MA 02021
U.S.

Tel: 1-866-332-8898 Website: www.investorcentre.com/cenovus

ADDITIONAL INFORMATION

Additional information relating to Cenovus is available on SEDAR at sedar.com and EDGAR at sec.gov. Additional financial information is contained in the Corporation's audited Consolidated Financial Statements and MD&A for the year ended December 31, 2016. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Cenovus's securities, securities authorized for issuance under its equity-based compensation plans and its statement of corporate governance practices, is included in the Corporation's management information circular for its most recent annual meeting of shareholders.

Additional financial information, including disclosure regarding the contribution of each reportable segment to revenues and earnings can be found in Cenovus's audited Consolidated Financial Statements and MD&A for the year ended December 31, 2016, which disclosure is incorporated by reference into this AIF.

As a Canadian corporation listed on the NYSE, Cenovus is not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, the Corporation is required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on Cenovus's website at cenovus.com, it is in compliance with the NYSE corporate governance standards in all significant respects.

ACCOUNTING MATTERS

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars. All references to "dollars", "C$" or to "$" are to Canadian dollars and all references to "US$" are to U.S. dollars. The information contained in this AIF is dated as at December 31, 2016 unless otherwise indicated. Numbers presented are rounded to the nearest whole number and tables may not add due to rounding.

Unless otherwise indicated, all financial information included in this AIF has been prepared in accordance with International Financial Reporting Standards, which are also generally accepted accounting principles for publicly accountable enterprises in Canada.

ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrels of oil equivalent per day
WTI	West Texas Intermediate

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBtu	million British thermal units
CBM	Coal Bed Methane

In this AIF, certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

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APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Cenovus Energy Inc. (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Evaluated Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	December 31, 2016	Canada	$23,995
GLJ Petroleum Consultants Ltd.	December 31, 2016	Canada	$1,262
			$25,257

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

7. We have no responsibility to update our reports referred to in paragraph five for events and circumstances occurring after their respective effective dates.

8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

/s/ P.A. Welch

P.A. Welch, P. Eng.
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

/s/ Keith M. Braaten

Keith M. Braaten, P. Eng
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 14, 2017

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Cenovus Energy Inc. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation;

(c) reviewed the reserves data with management and the independent qualified reserves evaluators; and

(d) reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management.

The Board of Directors, on the recommendation of the Reserves Committee, has approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ Brian C. Ferguson

Brian C. Ferguson
President & Chief Executive Officer

/s/ Ivor M. Ruste

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer

/s/ Michael A. Grandin

Michael A. Grandin
Director and Chair of the Board

/s/ Wayne G. Thomson

Wayne G. Thomson
Director and Chair of the Reserves Committee

February 15, 2017

APPENDIX C

AUDIT COMMITTEE MANDATE

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Cenovus Energy Inc. ("Cenovus" or the "Corporation") appointed to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- Oversee and monitor the effectiveness and integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting compliance.
- Oversee audits of the Corporation's financial statements.
- Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.
- Review and approve management's identification of principal financial risks and monitor the process to manage such risks.
- Oversee and monitor the Corporation's compliance with legal and regulatory requirements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing group.
- Provide an avenue of communication among the external auditors, management, the internal auditing group, and the Board.
- Report to the Board regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

CONSTITUTION, COMPOSITION AND DEFINITIONS

1. <u>Reporting</u>

The Committee shall report to the Board.

2. <u>Composition</u>

The Committee shall consist of not less than three and not more than eight directors as determined by the Board, all of whom shall qualify as independent directors pursuant to National Instrument 52-110 Audit Committees (as implemented by the Canadian Securities Administrators ("CSA") and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of accounting principles and financial statements;
- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's

financial statements, or experience actively supervising one or more persons engaged in such activities;

- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an “affiliated person” (as such term is defined in the *United States Securities Exchange Act of 1934*, as amended (the “Exchange Act”), and the rules, if any, adopted by the U.S. Securities and Exchange Commission (“SEC”) thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors’ fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an Audit Committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chair shall be a non-voting member of the Committee. See “Quorum” for further details.

3. Appointment of Committee Members

Committee members shall be appointed by the Board, effective after the election of directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

4. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

5. Chair

The Nominating and Corporate Governance Committee will recommend for approval to the Board an unrelated Director to act as Chair of the Committee. The Board shall appoint the Chair of the Committee.

If unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

The Chair presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chair in this section should be read in conjunction with the Committee Chair section of the Chair of the Board of Directors and Committee Chair General Guidelines.

6. Secretary

The Committee shall appoint a Secretary who need not be a member of the Committee. The Secretary shall keep minutes of the meetings of the Committee.

7. Meetings

The Committee shall meet at least quarterly. The Chair of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chair, the Chief Executive Officer, or any member of the Committee or by the external auditors.

Committee meetings may, by agreement of the Chair of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

8. **Notice of Meeting**

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 24 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

9. **Quorum**

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

10. **Attendance at Meetings**

The Chief Executive Officer, the Chief Financial Officer, the Comptroller and the head of internal audit are expected to be available to attend the Committee's meetings or portions thereof.

The Committee may, by specific invitation, have other resource persons in attendance.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.

11. **Minutes**

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors. The full Board of Directors shall be kept informed of the Committee's activities by a report following each Committee meeting.

RESPONSIBILITIES

In carrying out its mandate, the Committee is expected to:

12. **Review Procedures**

(a) Review and update the Committee's mandate annually, or sooner if the Committee deems it appropriate to do so. Review the summary of the Committee's composition and responsibilities in the Corporation's annual report, annual information form or other public disclosure documentation.

(b) Review the summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation's annual report and Annual Information Form filed with the CSA and the SEC.

13. **Annual Financial Statements**

(a) Discuss and review with management and the external auditors the Corporation's and any subsidiary with public securities' annual audited financial statements and related documents prior to their filing or distribution. Such review shall include:

(i) The annual financial statements and related notes including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Corporation's selection or application of accounting principles, any major issues as to the adequacy of the Corporation's internal controls and any special steps adopted in light of material control deficiencies.

(ii) Management's Discussion and Analysis.

(iii) The use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

(iv) The external auditors' audit examination of the financial statements and their report thereon.

(v) Any significant changes required in the external auditors' audit plan.

(vi) Any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information.

(vii) Other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

(b) Review and formally recommend approval to the Board of the Corporation's:

(i) Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

i. The accounting policies of the Corporation and any changes thereto.
ii. The effect of significant judgments, accruals and estimates.
iii. The manner of presentation of significant accounting items.
iv. The consistency of disclosure.

(ii) Management's Discussion and Analysis.

(iii) Annual Information Form as to financial information.

(iv) All prospectuses and information circulars as to financial information.

The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation's financial status depends, and which involve the most complex, subjective or significant judgmental decisions or assessments.

14. Quarterly Financial Statements

(a) Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation's:

(i) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.

(ii) Any significant changes to the Corporation's accounting principles.

(b) Review quarterly unaudited financial statements prior to their distribution of any subsidiary of the Corporation with public securities.

15. Other Financial Filings and Public Documents

Review and discuss with management financial information, including earnings press releases, the use of "pro forma" or non-GAAP financial information and earnings guidance, contained in any filings with the CSA or SEC or press releases related thereto, and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities.

16. Internal Control Environment

(a) Receive and review from management, the external auditors and the internal auditors an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.

(b) Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

(c) Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

(d) Review with the Chief Executive Officer, the Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting which could adversely affect the Corporation's ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the Exchange Act or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

(e) Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

17. Risk Oversight

Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.

18. Other Review Items

(a) Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

(b) Review all related party transactions between the Corporation and any executive officers or directors, including affiliations of any executive officers or directors.

(c) Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.

(d) Review legal and regulatory matters, including correspondence with and reports received from regulators and government agencies, that may have a material impact on the interim or annual financial statements and related corporate compliance policies and programs. Members from the Legal and Tax groups should be at the meeting in person to deliver their respective reports.

(e) Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

(f) Ensure that the Corporation's presentation of hydrocarbon reserves has been reviewed with the Reserves Committee of the Board.

(g) Review management's processes in place to prevent and detect fraud.

(h) Review:

  (i) procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters; and

  (ii) a summary of any significant investigations regarding such matters.

(i) Meet on a periodic basis separately with management.

19. External Auditors

(a) Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

(b) Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chair of the Committee or by a majority of the members of the Committee.

(c) Review and discuss a report from the external auditors at least quarterly regarding:

(i) All critical accounting policies and practices to be used;

(ii) All alternative treatments within accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

(iii) Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

(d) Obtain and review a report from the external auditors at least annually regarding:

(i) The external auditors' internal quality-control procedures.

(ii) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.

(iii) To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

(e) Review and discuss at least annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

(f) Review and evaluate annually:

(i) The external auditors' and the lead partner of the external auditors' team's performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation's shareholders or regarding the discharge of such external auditors.

(ii) The terms of engagement of the external auditors together with their proposed fees.

(iii) External audit plans and results.

(iv) Any other related audit engagement matters.

(v) The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

(vi) Review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for Cenovus.

(vii) Review any reports issued by CPAB regarding the audit of Cenovus.

(g) Conduct periodically a comprehensive review of the external auditor, with the outcome intended to assist the Committee to identify potential areas for improvement for the audit firm, and to reach a final conclusion on whether the auditor should be reappointed or the audit put out for tender.

(h) Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 19.(c) through (f), evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present to the Board its conclusions in this respect.

(i) Review the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

(j) Set clear hiring policies for the Corporation's hiring of employees or former employees of the external auditors.

(k) Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

(l) Consider and review with the external auditors, management and the head of internal audit:

(i) Significant findings during the year and management's responses and follow-up thereto.
(ii) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.
(iii) Any significant disagreements between the external auditors or internal auditors and management.
(iv) Any changes required in the planned scope of their audit plan.
(v) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.
(vi) The internal audit department mandate.
(vii) Internal audit's compliance with the Institute of Internal Auditors' standards.

20. Internal Audit Group and Independence

(a) Meet on a periodic basis separately with the head of internal audit.

(b) Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

(c) Confirm and assure, annually, the independence of the internal audit group and the external auditors.

21. Approval of Audit and Non-Audit Services

(a) Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the de minimus exception for non-audit services described in the Exchange Act or applicable CSA and SEC legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

(b) Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

(c) If the pre-approvals contemplated in paragraphs 21.(a) and (b) are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

(d) Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 21.(a) through (c). The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

(e) Establish policies and procedures for the pre-approvals described in paragraphs 21.(a) and (b) so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation to management of the Committee's responsibilities under the Exchange Act or applicable CSA and SEC legislation and regulations.

22. Other Matters

(a) Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

(b) Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

(c) Report Committee actions to the Board of Directors with such recommendations as the Committee may deem appropriate.

(d) Conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

(e) Determine the appropriate funding for payment by the Corporation (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee, and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

(f) Obtain assurance from the external auditors that no disclosure to the Committee is required pursuant to the provisions of the Exchange Act regarding the discovery of illegal acts by the external auditors.

(g) Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

(h) Consider for implementation any recommendations of the Nominating and Corporate Governance Committee of the Board with respect to the Committee's effectiveness, structure, processes or mandate.

(i) Perform such other functions as required by law, the Corporation's by-laws or the Board of Directors.

(j) Consider any other matters referred to it by the Board of Directors.

Revised Effective: February 10, 2015

APPENDIX D

NETBACK RECONCILIATIONS

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

The following tables provide a reconciliation of the financial components comprising Netbacks (in millions of dollars) to the nearest GAAP measure found in the annual and interim consolidated financial statements.

Bitumen

($ millions)	Basis of Netback Calculation			Adjustments		Per Consolidated Financial Statements[1]
Year ended December 31, 2016	Foster Creek	Christina Lake	Total Bitumen	Condensate	Inventory[2]	Total Oil Sands Crude Oil
Gross Sales	773	736	**1,509**	1,402	-	**2,911**
Royalties	-	9	**9**	-	-	**9**
Transportation and Blending	225	137	**362**	1,402	(44)	**1,720**
Operating	269	217	**486**	-	-	**486**
Netback	279	373	**652**	-	44	**696**
(Gain) Loss on Risk Management						**(179)**
Operating Margin						**875**
Three months ended December 31, 2016						
Gross Sales	283	260	**543**	408	-	**951**
Royalties	(2)	4	**2**	-	-	**2**
Transportation and Blending	53	31	**84**	408	-	**492**
Operating	77	61	**138**	-	-	**138**
Netback	155	164	**319**	-	-	**319**
(Gain) Loss on Risk Management						**(14)**
Operating Margin						**333**
Three months ended September 30, 2016						
Gross Sales	236	215	**451**	337	-	**788**
Royalties	1	3	**4**	-	-	**4**
Transportation and Blending	59	33	**92**	337	-	**429**
Operating	68	57	**125**	-	-	**125**
Netback	108	122	**230**	-	-	**230**
(Gain) Loss on Risk Management						**(35)**
Operating Margin						**265**
Three months ended June 30, 2016						
Gross Sales	189	196	**385**	322	-	**707**
Royalties	1	2	**3**	-	-	**3**
Transportation and Blending	65	34	**99**	322	(26)	**395**
Operating	57	44	**101**	-	-	**101**
Netback	66	116	**182**	-	26	**208**
(Gain) Loss on Risk Management						**(24)**
Operating Margin						**232**
Three months ended March 31, 2016						
Gross Sales	65	65	**130**	335	-	**465**
Royalties	-	-	**-**	-	-	**-**
Transportation and Blending	48	39	**87**	335	(18)	**404**
Operating	67	55	**122**	-	-	**122**
Netback	(50)	(29)	**(79)**	-	18	**(61)**
(Gain) Loss on Risk Management						**(106)**
Operating Margin						**45**

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

Crude Oil (Heavy, Light and Medium) and NGLs

($ millions)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements[1]
Year ended December 31, 2016	Heavy Crude Oil	Light and Medium Crude Oil	NGLs	Heavy, Light and Medium Crude Oil & NGLs	Condensate	Inventory[2]	Other	Total Conventional Crude Oil & NGLs
Gross Sales	380	442	11	**833**	103	-	-	**936**
Royalties	35	88	2	**125**	-	-	-	**125**
Transportation and Blending	49	25	-	**74**	103	(7)	-	**170**
Operating	142	149	-	**291**	-	-	(4)	**287**
Production and Mineral Taxes	-	12	-	**12**	-	-	-	**12**
Netback	154	168	9	**331**	-	7	4	**342**
(Gain) Loss on Risk Management								**(60)**
Operating Margin								**402**
Three months ended December 31, 2016								
Gross Sales	108	127	4	**239**	27	-	-	**266**
Royalties	11	34	-	**45**	-	-	-	**45**
Transportation and Blending	13	6	-	**19**	27	-	-	**46**
Operating	39	37	-	**76**	-	-	(2)	**74**
Production and Mineral Taxes	-	3	-	**3**	-	-	-	**3**
Netback	45	47	4	**96**	-	-	2	**98**
(Gain) Loss on Risk Management								**(2)**
Operating Margin								**100**
Three months ended September 30, 2016								
Gross Sales	104	114	3	**221**	21	-	-	**242**
Royalties	10	21	1	**32**	-	-	-	**32**
Transportation and Blending	13	6	-	**19**	21	-	-	**40**
Operating	32	33	-	**65**	-	-	-	**65**
Production and Mineral Taxes	-	4	-	**4**	-	-	-	**4**
Netback	49	50	2	**101**	-	-	-	**101**
(Gain) Loss on Risk Management								**(7)**
Operating Margin								**108**
Three months ended June 30, 2016								
Gross Sales	95	116	1	**212**	27	-	-	**239**
Royalties	10	20	1	**31**	-	-	-	**31**
Transportation and Blending	10	6	-	**16**	27	(3)	-	**40**
Operating	31	39	-	**70**	-	-	-	**70**
Production and Mineral Taxes	-	3	-	**3**	-	-	-	**3**
Netback	44	48	-	**92**	-	3	-	**95**
(Gain) Loss on Risk Management								**(11)**
Operating Margin								**106**
Three months ended March 31, 2016								
Gross Sales	73	85	3	**161**	28	-	-	**189**
Royalties	4	13	-	**17**	-	-	-	**17**
Transportation and Blending	13	7	-	**20**	28	(4)	-	**44**
Operating	40	40	-	**80**	-	-	(2)	**78**
Production and Mineral Taxes	-	2	-	**2**	-	-	-	**2**
Netback	16	23	3	**42**	-	4	2	**48**
(Gain) Loss on Risk Management								**(40)**
Operating Margin								**88**

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

Bitumen, Crude Oil (Heavy, Light and Medium) and NGLs

($ millions)	Basis of Netback Calculation			Adjustments			Per Consolidated Financial Statements[1]
Year ended December 31, 2016	Bitumen, and Heavy, Light and Medium Crude Oil	NGLs	Bitumen, Heavy, Light and Medium Crude Oil and NGLs	Condensate	Inventory[2]	Other	Total Crude Oil & NGLs
Gross Sales	2,331	11	**2,342**	1,505	-	-	**3,847**
Royalties	132	2	**134**	-	-	-	**134**
Transportation and Blending	436	-	**436**	1,505	(51)	-	**1,890**
Operating	777	-	**777**	-	-	(4)	**773**
Production and Mineral Taxes	12	-	**12**	-	-	-	**12**
Netback	974	9	**983**	-	51	4	**1,038**
(Gain) Loss on Risk Management							**(239)**
Operating Margin							**1,277**
Three months ended December 31, 2016							
Gross Sales	778	4	**782**	435	-	-	**1,217**
Royalties	47	-	**47**	-	-	-	**47**
Transportation and Blending	103	-	**103**	435	-	-	**538**
Operating	214	-	**214**	-	-	(2)	**212**
Production and Mineral Taxes	3	-	**3**	-	-	-	**3**
Netback	411	4	**415**	-	-	2	**417**
(Gain) Loss on Risk Management							**(16)**
Operating Margin							**433**
Three months ended September 30, 2016							
Gross Sales	669	3	**672**	358	-	-	**1,030**
Royalties	35	1	**36**	-	-	-	**36**
Transportation and Blending	111	-	**111**	358	-	-	**469**
Operating	190	-	**190**	-	-	-	**190**
Production and Mineral Taxes	4	-	**4**	-	-	-	**4**
Netback	329	2	**331**	-	-	-	**331**
(Gain) Loss on Risk Management							**(42)**
Operating Margin							**373**
Three months ended June 30, 2016							
Gross Sales	596	1	**597**	349	-	-	**946**
Royalties	33	1	**34**	-	-	-	**34**
Transportation and Blending	115	-	**115**	349	(29)	-	**435**
Operating	171	-	**171**	-	-	-	**171**
Production and Mineral Taxes	3	-	**3**	-	-	-	**3**
Netback	274	-	**274**	-	29	-	**303**
(Gain) Loss on Risk Management							**(35)**
Operating Margin							**338**
Three months ended March 31, 2016							
Gross Sales	288	3	**291**	363	-	-	**654**
Royalties	17	-	**17**	-	-	-	**17**
Transportation and Blending	107	-	**107**	363	(22)	-	**448**
Operating	202	-	**202**	-	-	(2)	**200**
Production and Mineral Taxes	2	-	**2**	-	-	-	**2**
Netback	(40)	3	**(37)**	-	22	2	**(13)**
(Gain) Loss on Risk Management							**(146)**
Operating Margin							**133**

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

Total Bitumen, Crude Oil (Heavy, Light and Medium), NGLs and Natural Gas

($ millions)	Basis of Netback Calculation			Adjustments			Per Consolidated Financial Statements[1]	
Year ended December 31, 2016	Bitumen, Heavy, Light and Medium Crude Oil and NGLs	Natural Gas	Total Bitumen, Heavy, Light and Medium Crude Oil, NGLs and Natural Gas	Condensate	Inventory[2]	Other	Other Products	Total Upstream
Gross Sales	2,342	335	**2,677**	1,505	-	2	12	**4,196**
Royalties	134	14	**148**	-	-	-	-	**148**
Transportation and Blending	436	17	**453**	1,505	(51)	-	-	**1,907**
Operating	777	165	**942**	-	-	(6)	9	**945**
Production and Mineral Taxes	12	-	**12**	-	-	-	-	**12**
Netback	983	139	**1,122**	-	51	8	3	**1,184**
(Gain) Loss on Risk Management								**(237)**
Operating Margin								**1,421**
Three months ended December 31, 2016								
Gross Sales	782	105	**887**	435	-	-	4	**1,326**
Royalties	47	6	**53**	-	-	-	-	**53**
Transportation and Blending	103	5	**108**	435	-	-	-	**543**
Operating	214	44	**258**	-	-	(3)	-	**255**
Production and Mineral Taxes	3	-	**3**	-	-	-	-	**3**
Netback	415	50	**465**	-	-	3	4	**472**
(Gain) Loss on Risk Management								**(15)**
Operating Margin								**487**
Three months ended September 30, 2016								
Gross Sales	672	90	**762**	358	-	1	2	**1,123**
Royalties	36	3	**39**	-	-	-	-	**39**
Transportation and Blending	111	4	**115**	358	-	-	-	**473**
Operating	190	37	**227**	-	-	-	3	**230**
Production and Mineral Taxes	4	-	**4**	-	-	-	-	**4**
Netback	331	46	**377**	-	-	1	(1)	**377**
(Gain) Loss on Risk Management								**(42)**
Operating Margin								**419**
Three months ended June 30, 2016								
Gross Sales	597	55	**652**	349	-	-	2	**1,003**
Royalties	34	2	**36**	-	-	-	-	**36**
Transportation and Blending	115	5	**120**	349	(29)	-	-	**440**
Operating	171	38	**209**	-	-	-	2	**211**
Production and Mineral Taxes	3	-	**3**	-	-	-	-	**3**
Netback	274	10	**284**	-	29	-	-	**313**
(Gain) Loss on Risk Management								**(35)**
Operating Margin								**348**
Three months ended March 31, 2016								
Gross Sales	291	85	**376**	363	-	1	4	**744**
Royalties	17	3	**20**	-	-	-	-	**20**
Transportation and Blending	107	3	**110**	363	(22)	-	-	**451**
Operating	202	46	**248**	-	-	(3)	4	**249**
Production and Mineral Taxes	2	-	**2**	-	-	-	-	**2**
Netback	(37)	33	**(4)**	-	22	4	-	**22**
(Gain) Loss on Risk Management								**(145)**
Operating Margin								**167**

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

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

Sales Volumes

(barrels per day, unless otherwise stated)	2016	Q4	Q3	Q2	Q1
Bitumen					
Foster Creek	**69,647**	79,827	76,318	62,089	60,169
Christina Lake	**79,481**	81,398	80,313	76,066	80,118
Crude Oil (Heavy, Light and Medium) and NGLs					
Heavy Oil	**28,958**	28,833	27,953	28,294	30,764
Light and Medium Oil	**25,965**	24,903	25,359	26,407	27,210
NGLs	**1,065**	1,177	1,074	799	1,208
Bitumen, Crude Oil (Heavy, Light and Medium) and NGLs Sales	**205,116**	216,138	211,017	193,655	199,469
Natural Gas Sales (MMcf per day)	**394**	379	392	399	408
Total Sales (BOE per day)	**270,783**	279,305	276,350	260,155	267,469

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2016

WHERE TO FIND:

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

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

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

The relabelling of Operating Cash Flow to Operating Margin and Cash Flow to Adjusted Funds Flow was based on recently published regulatory guidance. The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Financial Results, Operating Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2016, we had a market capitalization of approximately $17 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada. We conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in 2016 was approximately 205,860 barrels per day and our average natural gas production was 394 MMcf per day. The refining operations processed an average of 444,000 gross barrels per day of crude oil feedstock into an average of 471,000 gross barrels per day of refined products.

Our Strategy

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

Premium Quality Assets

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

Our producing asset mix includes:

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

Our marketing, products and transportation activities include:

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

Disciplined Manufacturing

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

Value-Added Integration

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

Focused Innovation

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

Trusted Reputation

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

Financial Strength

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

Dividend

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

Our Operations

Oil Sands

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

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

Conventional

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

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

(1) Includes NGLs.

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

Refining and Marketing

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

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

Refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

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

2016 HIGHLIGHTS

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

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

In 2016, we:

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

OPERATING RESULTS

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

Crude Oil Production Volumes

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

(1) NGLs include condensate volumes.

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

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

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

Natural Gas Production Volumes

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

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

Oil and Gas Reserves

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

Netbacks

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook").

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

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

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

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

Refining and Marketing

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

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

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

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

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

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

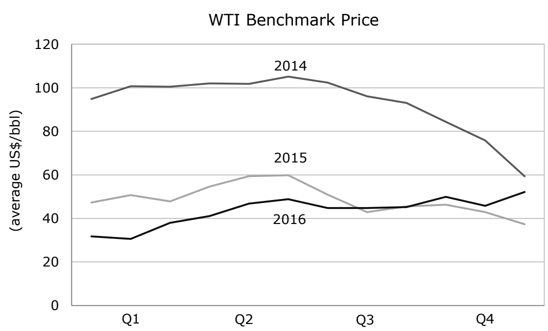
Crude Oil Benchmarks

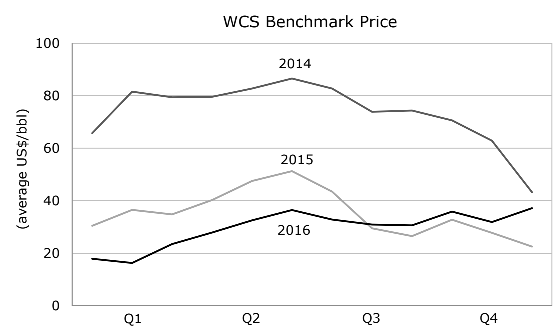
Average WTI declined US$5.48 per barrel in 2016 compared with 2015 as a result of excess crude oil and refined product inventories. Overall, average crude oil benchmark prices in 2016 continued to be volatile. We saw a steep decline in crude oil prices in the first quarter, with the WTI benchmark price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

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

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

The average WTI-Condensate differential narrowed in 2016 compared with 2015. Declining U.S. light oil production reduced condensate supply from the U.S. Gulf Coast while higher heavy oil production in Alberta increased demand. However, in the second quarter of 2016, the Alberta forest fires reduced heavy oil production and the associated demand for diluent.

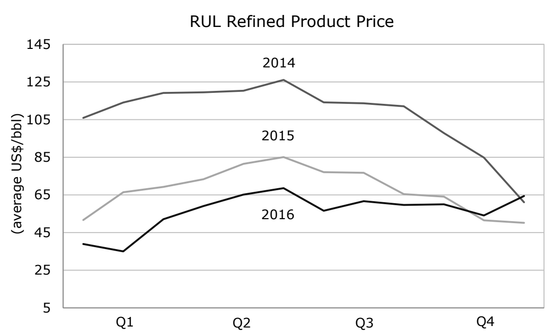


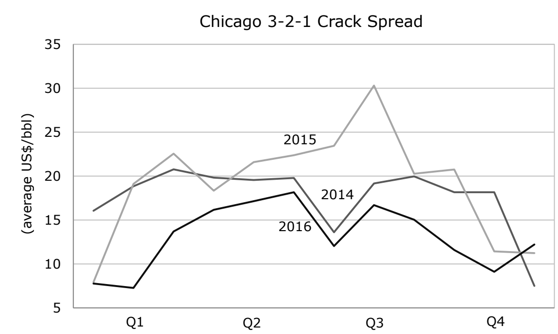


Refining Benchmarks

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

Average Chicago 3-2-1 crack spreads decreased in 2016 compared with 2015 due to higher global refined product inventory, and strengthening of the WTI benchmark price compared with Brent due to the lifting of the U.S. export ban. Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average natural gas prices decreased in 2016 compared with 2015 primarily due to high inventory levels in North America given a warmer than normal 2015/2016 winter and stable North American supply.

Foreign Exchange Benchmarks

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

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

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

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

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

Revenues

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

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

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

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

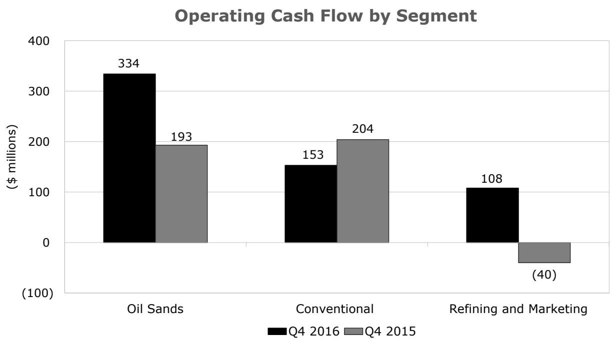
Overall, revenues decreased in 2015 compared with 2014 primarily due to lower crude oil and natural gas sales prices and a decline in refined product pricing, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar.

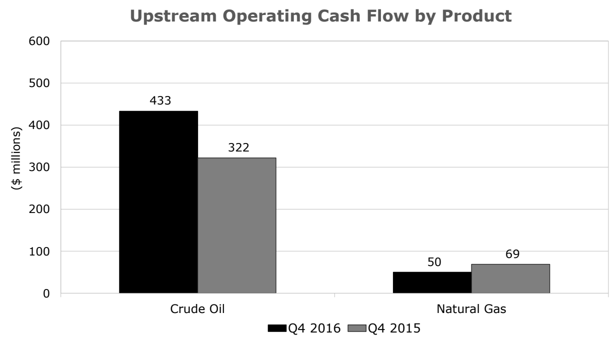
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Margin

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

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





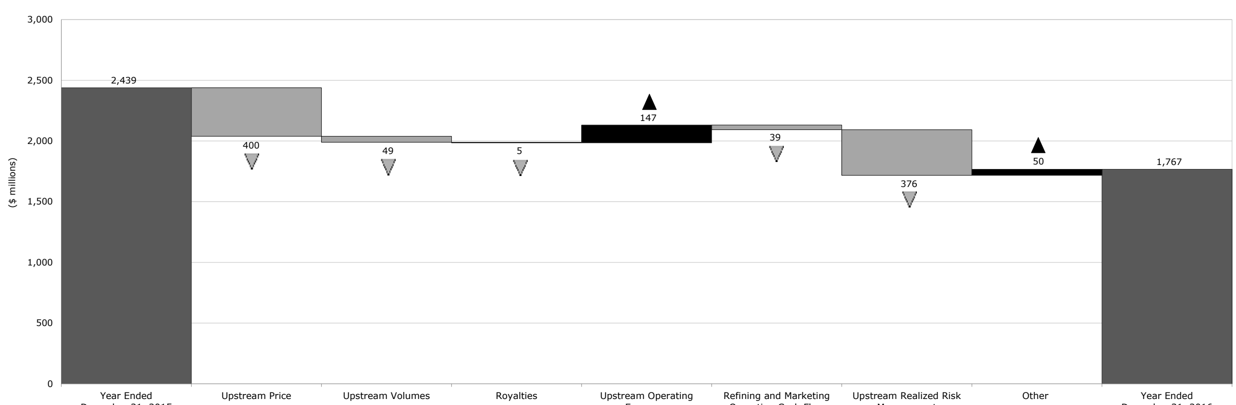
Operating Margin declined 28 percent in 2016 compared with 2015 primarily due to:

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

These declines to Operating Margin were partially offset by:

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

Operating Margin Variance



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

Cash From Operating Activities and Adjusted Funds Flow

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

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

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

Operating Earnings (Loss)

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

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

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

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

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

Refer to the Reportable Segments section for more details.

Net Earnings (Loss)

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

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

In 2016, Net Earnings declined primarily due to:

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

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

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

Net Capital Investment

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

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

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

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

Acquisitions and Divestitures

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

Capital Investment Decisions

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

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

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

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

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

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

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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

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

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

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

Revenues by Reportable Segment

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

OIL SANDS

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

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

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

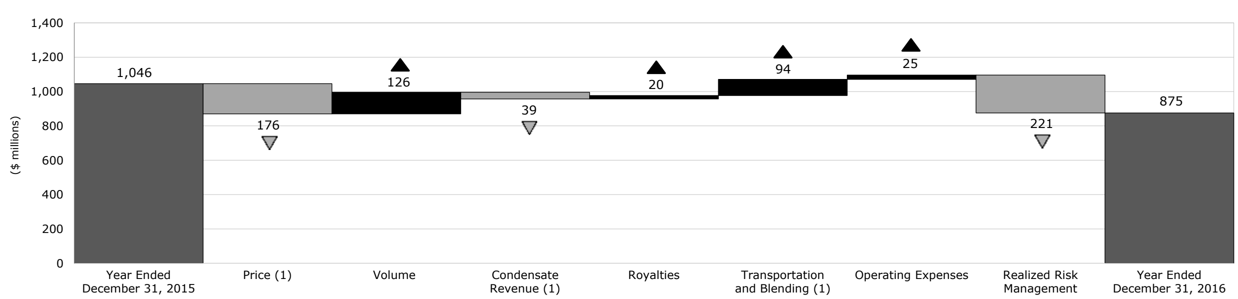
Oil Sands – Crude Oil

Financial Results

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

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

Operating Margin Variance



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

Revenues

Pricing

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

Our bitumen sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

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

Production Volumes

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

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

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

Condensate

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

Royalties

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

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

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

Effective Royalty Rates

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

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

Expenses

Transportation and Blending

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

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

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

Operating

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

Per-unit Operating Expenses

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

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

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

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

Netbacks [1]

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

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

Risk Management

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

Oil Sands – Natural Gas

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

Oil Sands – Capital Investment

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

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

Existing Projects

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

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

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

Emerging Projects

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

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

Drilling Activity

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

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

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

Future Capital Investment

While we expect continued crude oil price volatility in 2017, the progress we have made in 2016 in achieving sustainable cost reductions leaves us well positioned to consider advancing certain strategic growth projects. Our 2017 Oil Sands capital investment is forecast to be between $685 million and $815 million. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

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

Christina Lake is producing from phases A through F. Capital investment for 2017 is forecast to be between $300 million and $350 million, focused on sustaining capital and resuming construction of the phase G expansion, which had previously been deferred. Construction of phase G, which has an initial design capacity of 50,000 gross barrels per day, is expected to begin in the first half of 2017. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake and our new resource plays in 2017 is forecast to be between $60 million and $90 million, focusing on phase A engineering and equipment preservation related to the suspension of construction at Narrows Lake and a stratigraphic test well program at Telephone Lake. Further activity with respect to the SAGD pilot at Grand Rapids was deferred in 2016 in response to the low commodity price environment.

DD&A and Exploration Expense

DD&A

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

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

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

Exploration Expense

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

CONVENTIONAL

Our Conventional operations include reliable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO_2 enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood and waterflood technology and emerging tight oil assets in Alberta. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. The cash flows generated in our Conventional segment helps to fund future growth opportunities in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

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

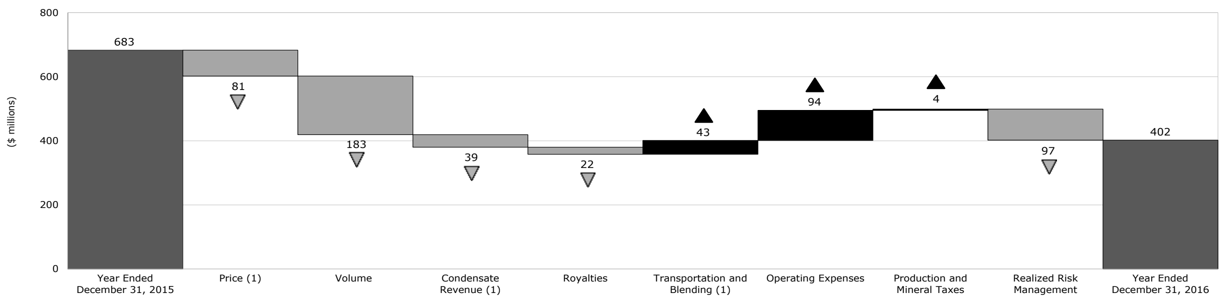
- Reducing our crude oil operating costs by $94 million or $1.60 per barrel;
- Crude oil and natural gas Netbacks, excluding realized risk management activities, of $16.17 per barrel (2015 – $20.92 per barrel) and $1.00 per Mcf (2015 – $1.58 per Mcf), respectively;
- Generating Operating Margin net of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

Conventional – Crude Oil

Financial Results

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

Operating Margin Variance



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

Revenues

Pricing

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

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

Production Volumes

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

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

Condensate

The heavy oil currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our blending ratios for Conventional heavy oil range between 10 percent and 16 percent. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential in 2016, the proportion of the cost of recovered condensate decreased.

Royalties

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

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

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

Expenses

Transportation and Blending

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

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

Operating

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

The per-unit decline was primarily due to:

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

These decreases were partially offset by lower production.

Netbacks [1]

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

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

Risk Management

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

Conventional – Natural Gas

Financial Results

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

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

Revenues

Pricing

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

Production

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

Royalties

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

Expenses

Transportation

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

Operating

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

Risk Management

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

Conventional – Capital Investment

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

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

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

Drilling Activity

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

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

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

Future Capital Investment

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

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

DD&A, Exploration Expense and Goodwill Impairment

DD&A

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

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

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

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

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

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

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

Exploration Expense

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

Goodwill Impairment

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

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries (the “Refineries”), which are located in the U.S. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In 2016, we loaded an average of 11,584 gross barrels per day (2015 – 6,530 gross barrels per day).

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

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

Refinery Operations [(1)]

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

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

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

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

Refining and Marketing Financial Results

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

Gross Margin

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

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

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

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

Expenses

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

Refining and Marketing – Capital Investment

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

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

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

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $20 million in 2016 primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

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

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

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

Expenses

General and Administrative

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

Finance Costs

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

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

Foreign Exchange

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

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

Other Income (Loss), Net

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

DD&A

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

Income Tax

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

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

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

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

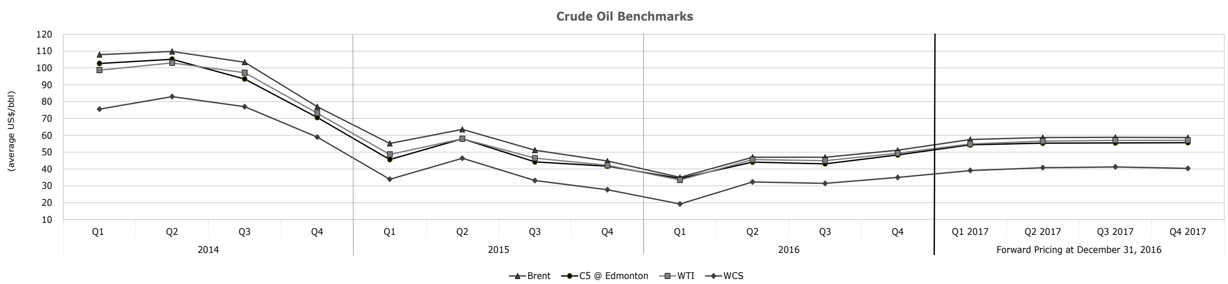
In 2016, we incurred losses for income tax purposes in Canada which will be carried back to recover income taxes previously paid or recognized as a deferred tax recovery. A current tax recovery was also recognized due to prior year adjustments. In 2015, current income tax expense included $391 million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

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

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

QUARTERLY RESULTS

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



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

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

Fourth Quarter 2016 Results Compared With the Fourth Quarter 2015

Production Volumes

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

Refinery Operations

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

Revenue

Revenues increased $718 million primarily due to:

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

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

Operating Margin

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

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

Cash From Operating Activities and Adjusted Funds Flow

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

Operating Earnings (Loss)

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

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

Net Earnings (Loss)

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

Capital Investment

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

OIL AND GAS RESERVES AND RESOURCES

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

Developments in 2016 compared with 2015 include:

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

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

Reserves

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

Reconciliation of Proved Reserves

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

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

Reconciliation of Probable Reserves

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

Contingent and Prospective Resources

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

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) There is uncertainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Cash From (Used In) Operating Activities

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

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

Cash From (Used In) Investing Activities

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

Cash From (Used In) Financing Activities

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

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

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

Available Sources of Liquidity

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

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

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

(1) Availability is subject to market conditions.

Committed Credit Facility

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

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

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

Base Shelf Prospectus

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

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

Financial Metrics

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

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

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

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

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

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

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

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

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

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

Share Capital and Stock-Based Compensation Plans

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

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

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

(1) Includes PSUs, RSUs, and DSUs.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services that were entered into in the normal course of business. Obligations are primarily related to demand charges on firm transportation agreements, operating leases on buildings, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. The items below have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise.

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

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

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

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

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

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

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

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

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Related Party Transactions

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

RISK MANAGEMENT

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

Risk Governance

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

Risk Assessment

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

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

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

Significant Risk Factors

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

Financial Risk

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

Commodity Prices

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

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

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

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

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

Impact of Financial Risk Management Activities

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

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

Commodity Price Sensitivities – Risk Management Positions

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

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

Risks Associated with Derivative Financial Instruments

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

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

Liquidity

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

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

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

Foreign Exchange Rates

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. To manage exposure to exchange rate fluctuations, Cenovus may enter into forward or other foreign exchange contracts. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Operational Risk

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

Market Access and Transportation Restrictions

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

Operational Outages and Major Environmental or Safety Incidents

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

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

Project Execution

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

Cost Management

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

Reserves Replacement

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

Leadership and Talent

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

Information Systems

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

Regulatory Risk

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

Regulatory Approvals

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

Abandonment and Reclamation Cost Risk

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

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

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

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

Tax Laws

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

United States Tax Risk

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

Royalty Regimes

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

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

Environmental Regulations

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

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

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

Species at Risk Act

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

Climate Change

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

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

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

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

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

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

Water Licences

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

Alberta's Land-Use Framework

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

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

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

Critical Judgments in Applying Accounting Policies

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

Joint Arrangements

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

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

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

Exploration and Evaluation Assets

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

Identification of CGUs

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

Key Sources of Estimation Uncertainty

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

Crude Oil and Natural Gas Reserves

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

Recoverable Amounts

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

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

Crude Oil and Natural Gas Prices

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

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

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

Discount and Inflation Rates

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

Decommissioning Costs

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

Income Tax Provisions

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

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

Changes in Accounting Policies

Cenovus adopted the following new amendment:

Liabilities Arising From Financing Activities

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

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2016. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Leases

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

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

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

Revenue Recognition

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

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

Financial Instruments

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

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

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

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

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

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

CONTROL ENVIRONMENT

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

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

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

CORPORATE RESPONSIBILITY

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

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

OUTLOOK

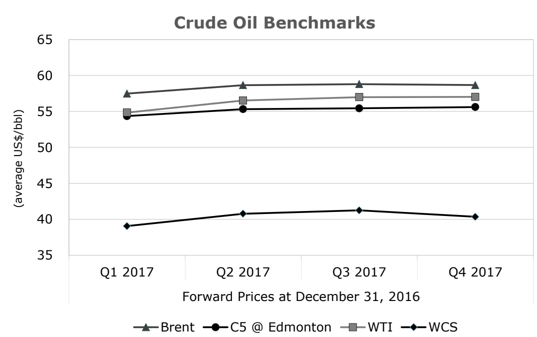
We anticipate ongoing price volatility for the foreseeable future and accordingly, we continue to be prudent in how we allocate capital and manage the pace at which we choose to invest. We will focus on maximizing our cost efficiencies and maintaining financial resilience while delivering safe and reliable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

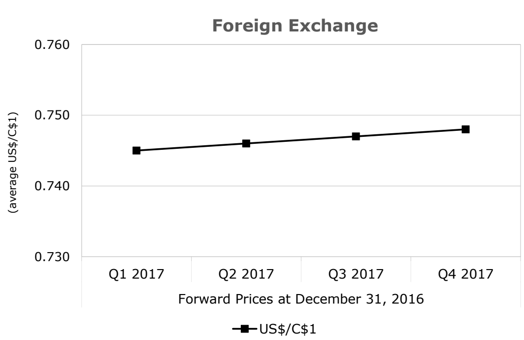
The following outlook commentary is focused on the next twelve months.

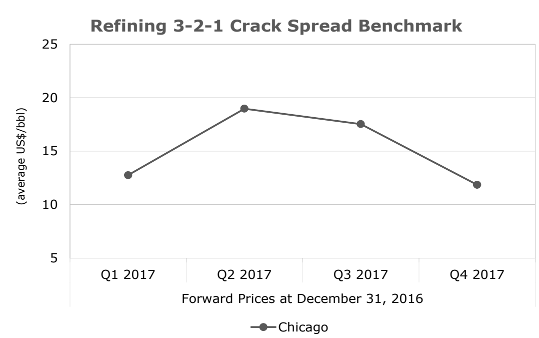
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

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







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

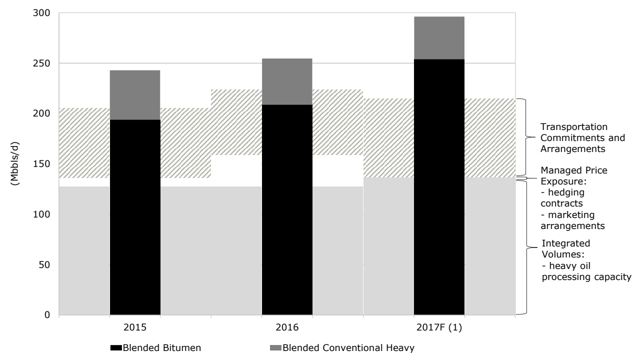
The Canadian dollar will likely continue to be tied to crude oil prices, tempered by rising interest rate expectations in the U.S. Overall, excluding the change in crude oil prices, a stronger Canadian dollar is expected to have a negative impact on our revenues and Operating Margin.

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

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

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

Protection From Canadian Price Differentials



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

Key Priorities for 2017

Disciplined and Value-added Growth

We anticipate capital investment in 2017 to be between $1.2 billion and $1.4 billion. We plan to direct the majority of our 2017 capital budget towards sustaining oil sands production and base production at our other operations. A portion of our capital budget is planned for growth at our existing oil sands assets as well as at our tight oil assets in southern Alberta. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

Sustainable Cost Improvements

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

Maintain Financial Resilience

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

Market Access

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

ADVISORY

Oil and Gas Information

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

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

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

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

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

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

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

Forward-looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "committed", "can be", "pursue", "capacity", "could", "should", "focus", "outlook", "potential", "priority", "may", "strategy", "forward", or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules, including expected timing for oil sands expansion phases and associated expected production capacities; expected impacts of completion of the Wood River debottlenecking project; projections for 2017 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; our future opportunities for oil development; forecast operating and financial results, including forecast sales prices, costs and cash flows; targets for our Debt to Capitalization and Debt to Adjusted EBITDA ratios; our ability to satisfy payment obligations as they become due; planned capital expenditures, including the amount, timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves; capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; our priorities for 2017; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices, derivative financial instruments and environmental regulations, including the CLA, CL Regulation, SGER and Carbon Strategy; the potential effectiveness of our risk management strategies; new accounting standards and the timing for the adoption thereof by Cenovus; and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2017 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

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

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

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

ABBREVIATIONS

The following abbreviations have been used in this document:

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

NETBACK RECONCILIATIONS

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

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

Sales Volumes

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

Total Crude Oil, NGLs and Natural Gas

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

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

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

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

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

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

Oil Sands Crude Oil

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

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

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

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

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

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

Conventional Crude Oil and NGLs

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

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

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

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

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

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

Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2016

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2016

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REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of five independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes – Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

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.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2016. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2016.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2016, as stated in their Report of Independent Registered Public Accounting Firm dated February 15, 2017. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Brian C. Ferguson

Brian C. Ferguson
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Ivor M. Ruste

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 15, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Cenovus Energy Inc.

We have audited the accompanying Consolidated Balance Sheets of Cenovus Energy Inc. as of December 31, 2016 and December 31, 2015 and the Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Shareholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2016. We also have audited Cenovus Energy Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO. Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management. Our responsibility is to express an opinion on these Consolidated Financial Statements and an opinion on Cenovus Energy Inc.'s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the Consolidated Financial Statements included examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall Consolidated Financial Statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of Cenovus Energy Inc. as of December 31, 2016 and December 31, 2015 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2016 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also, in our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Professional Accountants
Calgary, Alberta, Canada

February 15, 2017

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	2016	2015	2014
Revenues	1			
Gross Sales		**12,282**	13,207	20,107
Less: Royalties		**148**	143	465
		12,134	13,064	19,642
Expenses	1			
Purchased Product		**6,978**	7,374	10,955
Transportation and Blending		**1,901**	2,043	2,477
Operating		**1,683**	1,839	2,045
Production and Mineral Taxes		**12**	18	46
(Gain) Loss on Risk Management	31	**343**	(461)	(662)
Depreciation, Depletion and Amortization	9,16	**1,498**	2,114	1,946
Goodwill Impairment	9	**-**	-	497
Exploration Expense	9,15	**2**	138	86
General and Administrative		**326**	335	379
Finance Costs	5	**492**	482	445
Interest Income		**(52)**	(28)	(33)
Foreign Exchange (Gain) Loss, Net	6	**(198)**	1,036	411
Research Costs		**36**	27	15
(Gain) Loss on Divestiture of Assets	7	**6**	(2,392)	(156)
Other (Income) Loss, Net	8	**34**	2	(4)
Earnings (Loss) Before Income Tax		**(927)**	537	1,195
Income Tax Expense (Recovery)	10	**(382)**	(81)	451
Net Earnings (Loss)		**(545)**	618	744
Net Earnings (Loss) Per Share ($)	11			
Basic and Diluted		**(0.65)**	0.75	0.98

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions)

	Notes	2016	2015	2014
Net Earnings (Loss)		**(545)**	618	744
Other Comprehensive Income (Loss), Net of Tax	26			
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**(3)**	20	(18)
Items That May be Reclassified to Profit or Loss:				
Available for Sale Financial Assets – Change in Fair Value		**(2)**	6	-
Available for Sale Financial Assets – Reclassified to Profit or Loss		**1**	-	-
Foreign Currency Translation Adjustment		**(106)**	587	215
Total Other Comprehensive Income (Loss), Net of Tax		**(110)**	613	197
Comprehensive Income (Loss)		**(655)**	1,231	941

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	2016	2015
Assets			
Current Assets			
Cash and Cash Equivalents	12	**3,720**	4,105
Accounts Receivable and Accrued Revenues	13	**1,838**	1,251
Income Tax Receivable		**6**	6
Inventories	14	**1,237**	810
Risk Management	31,32	**21**	301
Total Current Assets		**6,822**	6,473
Exploration and Evaluation Assets	1,15	**1,585**	1,575
Property, Plant and Equipment, Net	1,16	**16,426**	17,335
Risk Management	31,32	**3**	-
Income Tax Receivable		**124**	90
Other Assets	8,18	**56**	76
Goodwill	1,19	**242**	242
Total Assets		**25,258**	25,791
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	20	**2,266**	1,702
Income Tax Payable		**112**	133
Risk Management	31,32	**293**	23
Total Current Liabilities		**2,671**	1,858
Long-Term Debt	21	**6,332**	6,525
Risk Management	31,32	**22**	7
Decommissioning Liabilities	22	**1,847**	2,052
Other Liabilities	23	**211**	142
Deferred Income Taxes	10	**2,585**	2,816
Total Liabilities		**13,668**	13,400
Shareholders' Equity		**11,590**	12,391
Total Liabilities and Shareholders' Equity		**25,258**	25,791
Commitments and Contingencies	34		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

/s/ Michael A. Grandin

Michael A. Grandin
Director
Cenovus Energy Inc.

/s/ Colin Taylor

Colin Taylor
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital (Note 25)	Paid in Surplus (Note 25)	Retained Earnings	AOCI [1] (Note 26)	**Total**
As at December 31, 2013	3,857	4,219	1,660	210	9,946
Net Earnings	-	-	744	-	744
Other Comprehensive Income	-	-	-	197	197
Total Comprehensive Income	-	-	744	197	941
Common Shares Issued Under Stock Option Plans	32	-	-	-	32
Stock-Based Compensation Expense	-	72	-	-	72
Dividends on Common Shares	-	-	(805)	-	(805)
As at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings	-	-	618	-	618
Other Comprehensive Income	-	-	-	613	613
Total Comprehensive Income	-	-	618	613	1,231
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Stock-Based Compensation Expense	-	39	-	-	39
Dividends on Common Shares	-	-	(710)	-	(710)
As at December 31, 2015	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(545)	-	(545)
Other Comprehensive Income (Loss)	-	-	-	(110)	(110)
Total Comprehensive Income (Loss)	-	-	(545)	(110)	(655)
Stock-Based Compensation Expense	-	20	-	-	20
Dividends on Common Shares	-	-	(166)	-	(166)
As at December 31, 2016	**5,534**	**4,350**	**796**	**910**	**11,590**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	2016	2015	2014
Operating Activities				
Net Earnings (Loss)		**(545)**	618	744
Depreciation, Depletion and Amortization	9,16	**1,498**	2,114	1,946
Goodwill Impairment	9	**-**	-	497
Exploration Expense	9,15	**2**	138	86
Deferred Income Taxes	10	**(209)**	(655)	359
Unrealized (Gain) Loss on Risk Management	31	**554**	195	(596)
Unrealized Foreign Exchange (Gain) Loss	6	**(189)**	1,097	411
(Gain) Loss on Divestiture of Assets	7	**6**	(2,392)	(156)
Current Tax on Divestiture of Assets	7	**-**	391	-
Unwinding of Discount on Decommissioning Liabilities	5,22	**130**	126	120
Onerous Contract Provisions, Net of Cash Paid		**53**	-	-
Other Asset Impairments	8	**30**	-	-
Other		**93**	59	68
Net Change in Other Assets and Liabilities		**(91)**	(107)	(135)
Net Change in Non-Cash Working Capital		**(471)**	(110)	182
Cash From Operating Activities		**861**	1,474	3,526
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	15	**(67)**	(138)	(279)
Capital Expenditures – Property, Plant and Equipment	16	**(967)**	(1,576)	(2,779)
Acquisition	17	**-**	(84)	-
Proceeds From Divestiture of Assets	7	**8**	3,344	276
Current Tax on Divestiture of Assets	7	**-**	(391)	-
Net Change in Investments and Other		**(1)**	3	(1,583)
Net Change in Non-Cash Working Capital		**(52)**	(270)	15
Cash From (Used in) Investing Activities		**(1,079)**	888	(4,350)
Net Cash Provided (Used) Before Financing Activities		**(218)**	2,362	(824)
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**-**	(25)	(18)
Common Shares Issued, Net of Issuance Costs	25	**-**	1,449	-
Common Shares Issued Under Stock Option Plans		**-**	-	28
Dividends Paid on Common Shares	11	**(166)**	(528)	(805)
Other		**(2)**	(2)	(2)
Cash From (Used in) Financing Activities		**(168)**	894	(797)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**1**	(34)	52
Increase (Decrease) in Cash and Cash Equivalents		**(385)**	3,222	(1,569)
Cash and Cash Equivalents, Beginning of Year		**4,105**	883	2,452
Cash and Cash Equivalents, End of Year		**3,720**	4,105	883
Supplementary Cash Flow Information	33			

See accompanying Notes to Consolidated Financial Statements.

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 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 margin. 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.

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 years ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues									
Gross Sales	**2,929**	3,030	5,036	**1,267**	1,709	3,225	**8,439**	8,805	12,658
Less: Royalties	**9**	29	236	**139**	114	229	**-**	-	-
	2,920	3,001	4,800	**1,128**	1,595	2,996	**8,439**	8,805	12,658
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**7,325**	7,709	11,767
Transportation and Blending	**1,721**	1,815	2,131	**186**	230	346	**-**	-	-
Operating	**501**	531	639	**444**	561	709	**742**	754	703
Production and Mineral Taxes	**-**	-	-	**12**	18	46	**-**	-	-
(Gain) Loss on Risk Management	**(179)**	(404)	(38)	**(58)**	(209)	(1)	**26**	(43)	(27)
Operating Margin [(1)]	**877**	1,059	2,068	**544**	995	1,896	**346**	385	215
Depreciation, Depletion and Amortization	**655**	697	625	**567**	1,148	1,082	**211**	191	156
Goodwill Impairment	**-**	-	-	**-**	-	497	**-**	-	-
Exploration Expense	**2**	67	4	**-**	71	82	**-**	-	-
Segment Income (Loss)	**220**	295	1,439	**(23)**	(224)	235	**135**	194	59

(1) Previously labelled Operating Cash Flow.

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Revenues						
Gross Sales	**(353)**	(337)	(812)	**12,282**	13,207	20,107
Less: Royalties	**-**	-	-	**148**	143	465
	(353)	(337)	(812)	**12,134**	13,064	19,642
Expenses						
Purchased Product	**(347)**	(335)	(812)	**6,978**	7,374	10,955
Transportation and Blending	**(6)**	(2)	-	**1,901**	2,043	2,477
Operating	**(4)**	(7)	(6)	**1,683**	1,839	2,045
Production and Mineral Taxes	**-**	-	-	**12**	18	46
(Gain) Loss on Risk Management	**554**	195	(596)	**343**	(461)	(662)
Depreciation, Depletion and Amortization	**65**	78	83	**1,498**	2,114	1,946
Goodwill Impairment	**-**	-	-	**-**	-	497
Exploration Expense	**-**	-	-	**2**	138	86
Segment Income (Loss)	**(615)**	(266)	519	**(283)**	(1)	2,252
General and Administrative	**326**	335	379	**326**	335	379
Finance Costs	**492**	482	445	**492**	482	445
Interest Income	**(52)**	(28)	(33)	**(52)**	(28)	(33)
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036	411	**(198)**	1,036	411
Research Costs	**36**	27	15	**36**	27	15
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	(156)	**6**	(2,392)	(156)
Other (Income) Loss, Net	**34**	2	(4)	**34**	2	(4)
	644	(538)	1,057	**644**	(538)	1,057
Earnings (Loss) Before Income Tax				**(927)**	537	1,195
Income Tax Expense (Recovery)				**(382)**	(81)	451
Net Earnings (Loss)				**(545)**	618	744

B) Financial Results by Upstream Product

	Crude Oil (1)								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues									
Gross Sales	**2,911**	3,000	4,963	**936**	1,239	2,456	**3,847**	4,239	7,419
Less: Royalties	**9**	29	233	**125**	103	217	**134**	132	450
	2,902	2,971	4,730	**811**	1,136	2,239	**3,713**	4,107	6,969
Expenses									
Transportation and Blending	**1,720**	1,814	2,130	**170**	213	326	**1,890**	2,027	2,456
Operating	**486**	511	615	**287**	381	505	**773**	892	1,120
Production and Mineral Taxes	**-**	-	-	**12**	16	37	**12**	16	37
(Gain) Loss on Risk Management	**(179)**	(400)	(38)	**(60)**	(157)	4	**(239)**	(557)	(34)
Operating Margin (2)	**875**	1,046	2,023	**402**	683	1,367	**1,277**	1,729	3,390

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues									
Gross Sales	**16**	22	67	**321**	450	744	**337**	472	811
Less: Royalties	**-**	-	3	**14**	11	12	**14**	11	15
	16	22	64	**307**	439	732	**323**	461	796
Expenses									
Transportation and Blending	**1**	1	1	**16**	17	20	**17**	18	21
Operating	**11**	15	17	**152**	175	198	**163**	190	215
Production and Mineral Taxes	**-**	-	-	**-**	2	9	**-**	2	9
(Gain) Loss on Risk Management	**-**	(4)	-	**2**	(52)	(5)	**2**	(56)	(5)
Operating Margin (2)	**4**	10	46	**137**	297	510	**141**	307	556

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues									
Gross Sales	**2**	8	6	**10**	20	25	**12**	28	31
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
	2	8	6	**10**	20	25	**12**	28	31
Expenses									
Transportation and Blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**4**	5	7	**5**	5	6	**9**	10	13
Production and Mineral Taxes	**-**	-	-	**-**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**-**	-	-	**-**	-	-	**-**	-	-
Operating Margin (2)	**(2)**	3	(1)	**5**	15	19	**3**	18	18

	Total Upstream								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Revenues									
Gross Sales	**2,929**	3,030	5,036	**1,267**	1,709	3,225	**4,196**	4,739	8,261
Less: Royalties	**9**	29	236	**139**	114	229	**148**	143	465
	2,920	3,001	4,800	**1,128**	1,595	2,996	**4,048**	4,596	7,796
Expenses									
Transportation and Blending	**1,721**	1,815	2,131	**186**	230	346	**1,907**	2,045	2,477
Operating	**501**	531	639	**444**	561	709	**945**	1,092	1,348
Production and Mineral Taxes	**-**	-	-	**12**	18	46	**12**	18	46
(Gain) Loss on Risk Management	**(179)**	(404)	(38)	**(58)**	(209)	(1)	**(237)**	(613)	(39)
Operating Margin (2)	**877**	1,059	2,068	**544**	995	1,896	**1,421**	2,054	3,964

(1) *Includes NGLs.*
(2) *Previously labelled Operating Cash Flow.*

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

	E&E [1]		PP&E [2]		Goodwill		Total Assets	
As at December 31,	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Oil Sands	**1,564**	1,560	**8,798**	8,907	**242**	242	**11,112**	11,069
Conventional	**21**	15	**3,080**	3,720	**-**	-	**3,196**	3,830
Refining and Marketing	**-**	-	**4,273**	4,398	**-**	-	**6,613**	5,844
Corporate and Eliminations	**-**	-	**275**	310	**-**	-	**4,337**	5,048
Consolidated	**1,585**	1,575	**16,426**	17,335	**242**	242	**25,258**	25,791

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

D) Geographical Information

	Revenues		
For the years ended December 31,	**2016**	2015	2014
Canada	**6,106**	6,264	10,139
United States	**6,028**	6,800	9,503
Consolidated	**12,134**	13,064	19,642

	Non-Current Assets [3]	
As at December 31,	**2016**	2015
Canada	**14,130**	14,921
United States	**4,179**	4,307
Consolidated	**18,309**	19,228

(3) Includes E&E, PP&E, goodwill and other assets.

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $974 million (2015 – $870 million; 2014 – $821 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2016, Cenovus had three customers (2015 – three; 2014 – three) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $4,742 million, $1,623 million and $1,400 million, respectively (2015 – $4,647 million, $1,705 million and $1,545 million; 2014 – $7,210 million, $2,668 million and $2,316 million), which are included in all of the Company's segments.

E) Capital Expenditures [4]

For the years ended December 31,	**2016**	2015	2014
Capital			
Oil Sands	**604**	1,185	1,986
Conventional	**171**	244	840
Refining and Marketing	**220**	248	163
Corporate	**31**	37	62
Capital Investment	**1,026**	1,714	3,051
Acquisition Capital			
Oil Sands	**11**	3	15
Conventional	**-**	1	3
Refining and Marketing	**-**	83	-
Total Capital Expenditures	**1,037**	1,801	3,069

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

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these 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 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors on February 15, 2017.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. Substantially all of the Company's Oil Sands and Refining activities are conducted through two joint operations, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), and accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses.

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period-end exchange rates for assets and liabilities, and using average rates over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period-end date. Any gains or losses are recorded in the Consolidated Statements of Earnings.

C) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs, and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Revenue from fee-for-service hydrocarbon trans-loading services is recognized in the period the service is provided.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

D) Transportation and Blending

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is sold.

E) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

F) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component and an other post-employment benefit plan ("OPEB").

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

G) Income Taxes

Income taxes comprise current and deferred taxes. Income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

H) Net Earnings per Share Amounts

Basic net earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

I) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

J) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

K) Exploration and Evaluation Assets

Costs incurred after the legal right to explore an area has been obtained, and before technical feasibility and commercial viability of the field/project/area have been established, are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired. E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

L) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net of any impairment losses. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Development and Production Assets

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties, as well as any E&E expenditures incurred in finding reserves of crude oil or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. For the purpose of this calculation, natural gas is converted to crude oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Other Upstream Assets

Other upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.

Refining Assets

The initial acquisition costs of refining PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

- Land improvements and buildings 25 to 40 years
- Office equipment and vehicles 3 to 20 years
- Refining equipment 5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Other Assets

Costs associated with the crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 40 years.

The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

M) Impairment

Non-Financial Assets

PP&E and E&E assets are reviewed separately for indicators of impairment quarterly or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is determined by estimating the discounted after-tax future net cash flows. For Cenovus's upstream assets, FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators ("IQREs"), and may consider an evaluation of comparable asset transactions.

If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

Impairment losses on PP&E and E&E assets are recognized in the Consolidated Statements of Earnings as additional DD&A and exploration expense, respectively.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flows and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.

An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

N) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within PP&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term.

O) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

P) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities, refining facilities and the crude-by-rail terminal. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset.

Actual expenditures incurred are charged against the accumulated liability.

Q) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

R) Stock-Based Compensation

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"). Stock-based compensation costs are recorded in general and administrative expense, or E&E and PP&E when directly related to exploration or development activities.

Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as stock-based compensation costs over the vesting period, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Tandem Stock Appreciation Rights

TSARs are accounted for as liability instruments, which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as stock-based compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation costs in the period they occur.

S) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets, investments in the equity of private companies and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, risk management liabilities, short-term borrowings and long-term debt.

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial instruments at initial recognition. Financial instruments are initially measured at fair value except in the case of "financial liabilities measured at amortized cost", which are initially measured at fair value net of directly attributable transaction costs.

As required by IFRS, the Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Fair Value through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases, the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenues, and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value, with changes in fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost. Available for sale financial assets comprise investments in the equity of private companies that the Company does not control or have significant influence over.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2016.

U) Recent Accounting Pronouncements

Amended Accounting Standard Adopted

The Company adopted the following new amendment:

Liabilities Arising From Financing Activities

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

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2016. The standards applicable to the Company are as follows and will be adopted on their respective effective dates:

Leases

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

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. It is anticipated that the adoption of IFRS 16 will have a material impact on the Company's Consolidated Balance Sheets due to material operating lease commitments as disclosed in Note 34. The Company plans to apply IFRS 16 initially on January 1, 2019; however, the transition approach on adoption has not yet been determined.

Revenue Recognition

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

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

Financial Instruments

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

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

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

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

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

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

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) 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 the Company's Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB.

As a result, these joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

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

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

Exploration and Evaluation Assets

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

Identification of CGUs

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

B) Key Sources of Estimation Uncertainty

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

Crude Oil and Natural Gas Reserves

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

Recoverable Amounts

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

Decommissioning Costs

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

Income Tax Provisions

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

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

5. FINANCE COSTS

For the years ended December 31,	**2016**	2015	2014
Interest Expense – Short-Term Borrowings and Long-Term Debt	**341**	328	285
Unwinding of Discount on Decommissioning Liabilities (Note 22)	**130**	126	120
Other	**21**	28	18
Interest Expense – Partnership Contribution Payable (1)	**-**	-	22
	492	482	445

(1) *In 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.*

6. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2016**	2015	2014
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**(196)**	1,064	458
Other	**7**	33	(47)
Unrealized Foreign Exchange (Gain) Loss	**(189)**	1,097	411
Realized Foreign Exchange (Gain) Loss	**(9)**	(61)	-
	(198)	1,036	411

7. DIVESTITURES

In the third quarter of 2016, the Company completed the sale of land to an unrelated third party for cash proceeds of $8 million, resulting in a loss of $5 million. In the second quarter of 2016, the Company sold equipment at a loss of $1 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

In the third quarter of 2015, the Company completed the sale of Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, to a third party for gross cash proceeds of $3.3 billion, resulting in a gain of $2.4 billion. HRP was a royalty business consisting of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. These assets, related liabilities and results of operations were reported in the Conventional segment.

The divestiture gave rise to a taxable gain for which the Company recognized a current tax expense of $391 million. The majority of HRP's assets had been acquired at a nominal cost and, as such, had minimal benefit from tax depreciation in prior years. For this reason, the current tax expense associated with the divestiture was specifically identifiable; therefore, it has been classified as an investing activity in the Consolidated Statements of Cash Flows.

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

In 2014, the Company completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million, resulting in a gain of $137 million. The Company also completed the sale of certain Bakken properties to an unrelated third party for net proceeds of $35 million, resulting in a gain of $16 million. Other divestitures in 2014 included the sale of certain non-core properties, resulting in a gain of $4 million. These assets and results of operations were reported in the Conventional segment.

8. OTHER (INCOME) LOSS, NET

As at December 31, 2016, due to the Government of Canada's decision to reject the Northern Gateway Pipeline project, the Company has written off $23 million of capitalized costs associated with its funding support unit in Northern Gateway Pipeline. In addition, $7 million of expected costs associated with termination have been recorded.

In 2016, $7 million (2015 – $nil) of certain investments in private equity companies were written off.

9. IMPAIRMENT CHARGES AND REVERSALS

A) CGU Net Impairments

The review of the Company's PP&E and E&E assets for indicators of impairment as at December 31, 2016 provided evidence that a portion of the impairment losses previously recorded should be reversed.

2016 Net Upstream Impairments

As at December 31, 2016, the recoverable value of the Northern Alberta CGU was estimated to be $1.1 billion. Earlier in 2016 and 2015, impairment losses of $380 million and $184 million, respectively, were recorded primarily due to a decline in long-term heavy crude oil prices and a slowing of the development plan. In the fourth quarter of 2016, the Company reversed $400 million of impairment losses, net of the DD&A that would have been recorded had no impairments been recorded. The reversal arose due to the increase in the CGU's estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. The impairment losses and subsequent reversal were recorded as 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.

As at December 31, 2016, the recoverable amount of the Suffield CGU was estimated to be $548 million. Earlier in 2016, an impairment loss of $65 million was recognized due to lower long-term forward natural gas and heavy crude oil prices. In the fourth quarter of 2016, the Company reversed the full amount of the impairment losses, net of the DD&A that would have been recorded had no impairment been recorded ($62 million). The reversal arose due to a decline in expected future royalties increasing the estimated recoverable amount of the CGU. The impairment loss and the subsequent reversal were recorded as DD&A in the Conventional segment. The Suffield CGU includes production of natural gas and heavy crude oil in Alberta on the Canadian Forces Base.

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

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2016 by the IQREs.

Crude Oil and Natural Gas Prices

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

	2017	2018	2019	2020	2021	Average Annual Increase Thereafter
WTI (US$/barrel) (1)	55.00	58.70	62.40	69.00	75.80	2.0%
WCS (C$/barrel) (2)	53.70	58.20	61.90	66.50	71.00	2.0%
AECO (C$/Mcf) (3) (4)	3.40	3.15	3.30	3.60	3.90	2.2%

(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 IQREs in preparing the reserves report. Based on the individual characteristics of the CGU, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

Sensitivities

The estimated recoverable value of the Northern Alberta CGU is sensitive to discount rate and forward price estimates over the life of the reserves. Changes to these assumptions, assuming all other variables remained constant, would have had the following impact on the 2016 net impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate (1)**	**Five Percent Increase in the Forward Price Estimates (1)**	**Five Percent Decrease in the Forward Price Estimates**
Increase (Decrease) to Net Impairment of PP&E	**132**	**(106)**	**(106)**	**270**

(1) The $106 million represents the remaining impairment loss that could be reversed as at December 31, 2016.

2015 Impairments

As at December 31, 2015, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of $184 million. The impairment was recorded as additional DD&A in the Conventional segment. Future cash flows for the CGU declined due to lower forward crude oil prices, a decline in reserves estimates and a slowing down of the development plan. This was partially offset by lower future development and operating costs.

The recoverable amount was determined using FVLCOD. The fair value of producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

There were no goodwill impairments for the twelve months ended December 31, 2015.

2014 Impairments

As at December 31, 2014, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount and the full amount of the impairment was attributed to goodwill. An impairment loss of $497 million was recorded as goodwill impairment on the Consolidated Statements of Earnings. The operating results of the CGU are included in the Conventional segment. Future cash flows for the CGU declined due to lower crude oil prices and a slowing down of the Pelican Lake development plan.

The recoverable amount was determined using FVLCOD. 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, prepared by Cenovus's IQREs (Level 3). The fair value of E&E assets was determined using market comparable transactions (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 11 percent. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2014, the recoverable amount of the Northern Alberta CGU was estimated to be $2.3 billion.

B) Asset Impairments

Exploration and Evaluation Assets

In 2016, $2 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable. This impairment loss was recorded as exploration expense in the Oil Sands segment.

In 2015, $138 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense. This impairment loss included $67 million and $71 million within the Oil Sands and Conventional segments, respectively.

In 2014, $82 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense in the Conventional segment. In addition, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense in the Oil Sands segment.

Property, Plant and Equipment, Net

In the fourth quarter of 2016, the Company recorded an impairment loss of $20 million primarily related to equipment that was written down to its recoverable amount. This impairment was recorded as additional DD&A in the Conventional segment.

In the third quarter of 2016, the Company recorded an impairment loss of $16 million related to preliminary engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount. This impairment loss was recorded as additional DD&A in the Oil Sands segment. In the second quarter of 2016, $4 million of leasehold improvements were written off. This impairment loss was recorded as additional DD&A in the Corporate and Eliminations segment.

In 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded as additional DD&A in the Oil Sands segment. The Company did not have future plans for the assets and did not believe it would recover the carrying amount through a sale.

In 2014, the Company impaired equipment for $52 million. The Company did not have future plans for the equipment and did not believe it would recover the carrying amount through a sale. The asset was written down to FVLCOD. Additionally, a minor natural gas property was shut-in and abandonment commenced, resulting in an impairment of $13 million. These impairments were recorded as additional DD&A in the Conventional segment.

10. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2016**	2015	2014
Current Tax			
Canada	**(174)**	586	94
United States	**1**	(12)	(2)
Total Current Tax Expense (Recovery)	**(173)**	574	92
Deferred Tax Expense (Recovery)	**(209)**	(655)	359
	(382)	(81)	451

In 2016, the Company recorded a current tax recovery due to the carryback of losses for income tax purposes and prior year adjustments.

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The Government of Alberta enacted a two percent increase in the corporate income tax rate effective July 1, 2015, increasing the statutory tax rate for the year to 26.1 percent. As a result, the Company's deferred income tax liability increased by $161 million for the year ended December 31, 2015.

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

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

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

As at December 31,	**2016**	2015
Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**6**	100
Deferred Tax Liabilities to be Settled After More Than 12 Months	**3,147**	3,051
	3,153	3,151
Deferred Income Tax Assets		
Deferred Tax Assets to be Recovered Within 12 Months	**(117)**	(42)
Deferred Tax Assets to be Recovered After More Than 12 Months	**(451)**	(293)
	(568)	(335)
Net Deferred Income Tax Liability	**2,585**	2,816

The deferred income tax assets and liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and may not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	Property, Plant and Equipment	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2014	3,106	167	121	41	3,435
Charged (Credited) to Earnings	(246)	(167)	(39)	(24)	(476)
Charged (Credited) to OCI	192	-	-	-	192
As at December 31, 2015	3,052	-	82	17	3,151
Charged (Credited) to Earnings	118	-	(76)	(16)	26
Charged (Credited) to OCI	(24)	-	-	-	(24)
As at December 31, 2016	**3,146**	**-**	**6**	**1**	**3,153**

Deferred Income Tax Assets	Unused Tax Losses	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2014	(72)	-	(4)	(57)	(133)
Charged (Credited) to Earnings	(80)	(36)	(4)	(59)	(179)
Charged (Credited) to OCI	(20)	-	-	(3)	(23)
As at December 31, 2015	(172)	(36)	(8)	(119)	(335)
Charged (Credited) to Earnings	(102)	36	(77)	(92)	(235)
Charged (Credited) to OCI	4	-	-	(2)	2
As at December 31, 2016	**(270)**	**-**	**(85)**	**(213)**	**(568)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2014	3,302
Charged (Credited) to Earnings	(655)
Charged (Credited) to OCI	169
Net Deferred Income Tax Liabilities as at December 31, 2015	2,816
Charged (Credited) to Earnings	(209)
Charged (Credited) to OCI	(22)
Net Deferred Income Tax Liabilities as at December 31, 2016	**2,585**

No deferred tax liability has been recognized as at December 31, 2016 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future. As at December 31, 2016, the Company had temporary differences of $7,457 million (2015 – $6,692 million) in respect of certain of these investments where, on dissolution or sale, a tax liability may exist.

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	**2016**	2015
Canada	**4,273**	4,882
United States	**2,036**	2,119
	6,309	7,001

As at December 31, 2016, the above tax pools included $46 million (2015 – $13 million) of Canadian non-capital losses and $623 million (2015 – $380 million) of U.S. federal net operating losses. These losses expire no earlier than 2031.

Also included in the December 31, 2016 tax pools are Canadian net capital losses totaling $43 million (2015 – $44 million), which are available for carry forward to reduce future capital gains. Of these losses, $40 million are unrecognized as a deferred income tax asset as at December 31, 2016 (2015 – $41 million). Recognition is dependent on future capital gains. The Company has not recognized $730 million (2015 – $828 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

11. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share

For the years ended December 31,	2016	2015	2014
Net Earnings (Loss) – Basic and Diluted ($ millions)	**(545)**	618	744
Weighted Average Number of Shares – Basic (millions)	**833.3**	818.7	756.9
Dilutive Effect of Cenovus TSARs	**-**	-	0.7
Weighted Average Number of Shares – Diluted	**833.3**	818.7	757.6
Net Earnings (Loss) Per Share – Basic and Diluted ($)	**(0.65)**	0.75	0.98

B) Dividends Per Share

For the year ended December 31, 2016, the Company paid dividends of $166 million or $0.20 per share, all of which were paid in cash (2015 – $710 million or $0.8524 per share, including cash dividends of $528 million; 2014 – $805 million or $1.0648 per share, all of which were paid in cash). The Cenovus Board of Directors declared a first quarter dividend of $0.05 per share, payable on March 31, 2017, to common shareholders of record as of March 15, 2017.

12. CASH AND CASH EQUIVALENTS

As at December 31,	2016	2015
Cash	**542**	323
Short-Term Investments	**3,178**	3,782
	3,720	4,105

13. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	2016	2015
Accruals	**1,606**	1,037
Partner Advances	**-**	35
Prepaids and Deposits	**127**	71
Note Receivable From Partner (1)	**50**	-
Trade	**29**	61
Joint Operations Receivables	**11**	13
Other	**15**	34
	1,838	1,251

(1) *Note receivable from partner is interest bearing at a rate of 1.6783 percent per annum and is due on demand.*

14. INVENTORIES

As at December 31,	2016	2015
Product		
Refining and Marketing	**1,006**	591
Oil Sands	**156**	158
Conventional	**20**	11
Parts and Supplies	**55**	50
	1,237	810

During the year ended December 31, 2016, approximately $9,964 million of produced and purchased inventory was recorded as an expense (2015 – $10,618 million; 2014 – $15,065 million).

As a result of a decline in commodity prices, Cenovus recorded a write-down of its product inventory of $4 million from cost to net realizable value as at December 31, 2016 (2015 – $66 million).

15. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2014	1,625
Additions	138
Acquisitions	3
Transfers to PP&E (Note 16)	(49)
Exploration Expense (Note 9)	(138)
Change in Decommissioning Liabilities	(4)
As at December 31, 2015	1,575
Additions	67
Transfers to PP&E (Note 16)	(49)
Exploration Expense (Note 9)	(2)
Change in Decommissioning Liabilities	(6)
As at December 31, 2016	**1,585**

16. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2014	31,701	329	4,151	910	37,091
Additions	1,289	2	240	45	1,576
Acquisition (Note 17)	1	-	-	83	84
Transfers From E&E Assets (Note 15)	49	-	-	-	49
Change in Decommissioning Liabilities	(635)	-	1	(1)	(635)
Exchange Rate Movements and Other	(1)	-	814	-	813
Divestitures (Note 7)	(923)	-	-	-	(923)
As at December 31, 2015	31,481	331	5,206	1,037	38,055
Additions	717	2	213	38	970
Transfers From E&E Assets (Note 15)	49	-	-	-	49
Change in Decommissioning Liabilities	(267)	-	(8)	-	(275)
Exchange Rate Movements and Other	(16)	-	(152)	(1)	(169)
Divestitures (Note 7)	(23)	-	-	-	(23)
As at December 31, 2016	**31,941**	**333**	**5,259**	**1,074**	**38,607**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2014	17,153	233	584	558	18,528
DD&A	1,601	44	189	80	1,914
Impairment Losses (Note 9)	200	-	-	-	200
Exchange Rate Movements and Other	(1)	-	123	1	123
Divestitures (Note 7)	(45)	-	-	-	(45)
As at December 31, 2015	18,908	277	896	639	20,720
DD&A	1,173	31	205	66	1,475
Impairment Losses (Note 9)	481	-	-	4	485
Reversal of Impairment Losses (Note 9)	(462)	-	-	-	(462)
Exchange Rate Movements and Other	(4)	-	(25)	-	(29)
Divestitures (Note 7)	(8)	-	-	-	(8)
As at December 31, 2016	**20,088**	**308**	**1,076**	**709**	**22,181**
CARRYING VALUE					
As at December 31, 2014	14,548	96	3,567	352	18,563
As at December 31, 2015	12,573	54	4,310	398	17,335
As at December 31, 2016	**11,853**	**25**	**4,183**	**365**	**16,426**

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

PP&E includes the following amounts in respect of assets under construction and not subject to DD&A:

As at December 31,	**2016**	2015
Development and Production	**537**	537
Refining Equipment	**206**	265
	743	802

17. ACQUISITION

In 2015, the Company completed the acquisition of a crude-by-rail terminal for cash consideration of $75 million, plus adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with the acquisition, the Company assumed an associated decommissioning liability of $4 million, working capital of $1 million and net transportation commitments of $92 million. Transaction costs associated with the acquisition were expensed. These assets, related liabilities and results of operations are reported in the Refining and Marketing segment.

18. OTHER ASSETS

As at December 31,	**2016**	2015
Equity Investments	**35**	46
Long-Term Receivables	**15**	1
Prepaids	**5**	7
Other (Note 8)	**1**	22
	56	76

19. GOODWILL

All of the Company's goodwill arose in 2002 upon the formation of its predecessor corporation. As at December 31, 2016 and 2015, the $242 million carrying amount of goodwill was associated with the Company's Primrose (Foster Creek) CGU.

For the purposes of impairment testing, goodwill is allocated to the CGU to which it relates. The assumptions used to test Cenovus's goodwill for impairment as at December 31, 2016 are consistent to those disclosed in Note 9.

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2016**	2015
Accruals	**1,927**	1,366
Trade	**105**	68
Interest	**72**	73
Note Payable to Partner (1)	**50**	-
Employee Long-Term Incentives	**42**	47
Onerous Contract Provisions	**18**	-
Other	**52**	113
Partner Advances	**-**	35
	2,266	1,702

(1) Note payable to partner is interest bearing at a rate of 1.6783 percent per annum and is due on demand.

21. LONG-TERM DEBT

As at December 31,		2016	2015
Revolving Term Debt [(1)]	A	**-**	-
U.S. Dollar Denominated Unsecured Notes	B	**6,378**	6,574
Total Debt Principal	C	**6,378**	6,574
Debt Discounts and Transaction Costs	D	**(46)**	(49)
		6,332	6,525

(1) Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate ("LIBOR") based loans, prime rate loans and U.S. base rate loans.

The weighted average interest rate on outstanding debt for the year ended December 31, 2016 was 5.3 percent (2015 – 5.3 percent).

A) Revolving Term Debt

As at December 31, 2016, Cenovus had in place a committed credit facility in the amount of $4.0 billion or the equivalent amount in U.S. dollars. On April 22, 2016, the Company renegotiated the maturity date of the $1.0 billion tranche from November 30, 2017 to April 30, 2019. The $3.0 billion tranche matures on November 30, 2019. The maturity dates are extendable from time to time, at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. As at December 31, 2016, there were no amounts drawn on Cenovus's committed bank credit facility (2015 – $nil).

B) Unsecured Notes

Unsecured notes are composed of:

As at December 31,	US$ Principal Amount	2016	2015
5.70% due October 15, 2019	1,300	**1,746**	1,799
3.00% due August 15, 2022	500	**671**	692
3.80% due September 15, 2023	450	**604**	623
6.75% due November 15, 2039	1,400	**1,880**	1,938
4.45% due September 15, 2042	750	**1,007**	1,038
5.20% due September 15, 2043	350	**470**	484
	4,750	**6,378**	6,574

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. As at December 31, 2016, no issuances have been made under the US$5.0 billion base shelf prospectus.

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

C) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	**Total C$ Equivalent**
2017	-	-	**-**
2018	-	-	**-**
2019	1,300	-	**1,746**
2020	-	-	**-**
2021	-	-	**-**
Thereafter	3,450	-	**4,632**
	4,750	-	**6,378**

D) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are amortized over the remaining term of the committed credit facility. During 2016, additional transaction costs of $1 million were recorded (2015 – $3 million).

E) Reconciliation of Liabilities to Cash Flows Arising From Financing Activities

	Short-Term Borrowings	Long-Term Borrowings
As at December 31, 2015	-	6,525
Changes From Financing Cash Flows	-	-
Non-Cash Changes:		
Unrealized Foreign Exchange (Gain) Loss (Note 6)	-	(196)
Amortization of Debt Discounts	-	3
As at December 31, 2016	**-**	**6,332**

22. DECOMMISSIONING LIABILITIES

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

As at December 31,	2016	2015
Decommissioning Liabilities, Beginning of Year	**2,052**	2,616
Liabilities Incurred	**11**	10
Liabilities Acquired	**-**	4
Liabilities Settled	**(51)**	(62)
Liabilities Divested	**(1)**	-
Change in Estimated Future Cash Flows	**(423)**	(70)
Change in Discount Rate	**131**	(579)
Unwinding of Discount on Decommissioning Liabilities	**130**	126
Foreign Currency Translation	**(2)**	7
Decommissioning Liabilities, End of Year	**1,847**	2,052

As at December 31, 2016, the undiscounted amount of estimated future cash flows required to settle the obligation is $6,270 million (2015 – $6,665 million), which has been discounted using a credit-adjusted risk-free rate of 5.9 percent (2015 – 6.4 percent). An inflation rate of two percent (2015 – two percent) was used to calculate the decommissioning provision. Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. The Company expects to settle approximately $55 million to $90 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from lower cost estimates, partially offset by accelerated timing of decommissioning liabilities over the estimated life of the reserves.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2016		2015	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(248)**	**327**	(247)	319
One Percent Decrease	**317**	**(259)**	308	(259)

23. OTHER LIABILITIES

As at December 31,	2016	2015
Employee Long-Term Incentives	**72**	40
Pension and OPEB (Note 24)	**71**	66
Onerous Contract Provisions	**35**	-
Other	**33**	36
	211	142

24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and OPEB. Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria may move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2014 and the next required actuarial valuation will be as at December 31, 2017.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		OPEB	
As at December 31,	2016	2015	2016	2015
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**168**	200	**26**	23
Current Service Costs	**14**	19	**(3)**	3
Interest Costs [1]	**7**	8	**1**	1
Benefits Paid	**(25)**	(6)	**(1)**	(1)
Plan Participant Contributions	**2**	3	**-**	-
Past Service Costs – Curtailments	**-**	(5)	**-**	-
Settlements	**-**	(20)	**-**	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	**-**	(3)	**-**	-
(Gains) Losses from Changes in Financial Assumptions	**7**	(28)	**-**	-
Defined Benefit Obligation, End of Year	**173**	168	**23**	26
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**128**	139	**-**	-
Employer Contributions	**14**	16	**-**	-
Plan Participant Contributions	**2**	3	**-**	-
Benefits Paid	**(25)**	(6)	**-**	-
Settlements	**-**	(23)	**-**	-
Interest Income [1]	**3**	2	**-**	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**3**	(3)	**-**	-
Fair Value of Plan Assets, End of Year	**125**	128	**-**	-
Pension and OPEB (Liability) [2]	**(48)**	(40)	**(23)**	(26)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.

The weighted average duration of the defined benefit pension and OPEB obligations are 16 years and 11 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Defined Benefit Plan Cost						
Current Service Costs	**14**	19	15	**(3)**	3	2
Past Service Costs – Curtailments	**-**	(5)	-	**-**	-	-
Net Settlement Costs	**-**	3	-	**-**	-	-
Net Interest Costs	**4**	6	3	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(3)**	3	(8)	**-**	-	-
(Gains) Losses from Experience Adjustments	**-**	(3)	-	**-**	-	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	-	(1)	**-**	-	-
(Gains) Losses from Changes in Financial Assumptions	**7**	(28)	31	**-**	-	2
Defined Benefit Plan Cost (Gain)	**22**	(5)	40	**(2)**	4	5
Defined Contribution Plan Cost	**25**	29	30	**-**	-	-
Total Plan Cost	**47**	24	70	**(2)**	4	5

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored quarterly and is re-balanced as necessary. The asset allocation structure targets an investment of 50 to 75 percent in equity securities, 25 to 35 percent in fixed income assets, zero to 15 percent in real estate assets and zero to 10 percent in cash and cash equivalents.

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the plan assets is:

As at December 31,	**2016**	2015
Equity Funds	**73**	73
Bond Funds	**25**	31
Non-Invested Assets	**13**	17
Real Estate Funds	**9**	4
Cash and Cash Equivalents	**5**	3
	125	128

Fair value of equity securities and bond funds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of the real estate fund reflects the market value and the fund manager's appraisal value of the assets.

Equity securities do not include any direct investments in Cenovus shares.

D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on actuarial valuations and direction of the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. The expected employer contributions for the year ended December 31, 2017 are $14 million for the defined benefit pension plan and $nil for the OPEB. The OPEB is funded on an as required basis.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			OPEB		
For the years ended December 31,	**2016**	2015	2014	**2016**	2015	2014
Discount Rate	**3.75%**	4.00%	3.75%	**3.75%**	3.75%	3.75%
Future Salary Growth Rate	**3.80%**	3.80%	4.32%	**5.15%**	5.15%	5.65%
Average Longevity (years)	**87.9**	88.3	88.3	**87.9**	88.3	88.3
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	7.00%	7.00%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

Sensitivities

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumptions is:

	2016		2015	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
One Percent Change:				
Discount Rate	**(25)**	**32**	(27)	35
Future Salary Growth Rate	**3**	**(3)**	3	(3)
Health Care Cost Trend Rate	**2**	**(1)**	2	(2)
One Year Change in Assumed Life Expectancy	**4**	**(4)**	4	(4)

The above sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability recorded on the Consolidated Balance Sheets.

F) Risks

Through its defined benefit pension and OPEB plans, the Company is exposed to actuarial risks, such as longevity risk, interest rate risk, investment risk and salary risk.

Longevity Risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of participants will increase the defined benefit plan obligation.

Interest Rate Risk

A decrease in corporate bond yields will increase the defined benefit plan obligation, although this will be partially offset by an increase in the return on debt holdings.

Investment Risk

The present value of the defined benefit plan obligation is calculated using a discount rate determined by reference to high quality corporate bond yields. If the return on plan assets is below this rate, a plan deficit will result. Due to the long-term nature of the plan liabilities, a higher portion of the plan assets are invested in equity securities than in debt instruments and real estate.

Salary Risk

The present value of the defined benefit plan obligation is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the defined benefit obligation.

25. 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

	2016		2015	
As at December 31,	**Number of Common Shares** (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**833,290**	**5,534**	757,103	3,889
Common Shares Issued, Net of Issuance Costs	**-**	**-**	67,500	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	**-**	**-**	8,687	182
Outstanding, End of Year	**833,290**	**5,534**	833,290	5,534

On March 3, 2015, Cenovus issued 67.5 million common shares at a price of $22.25 per common share. Share issuance costs of $53 million were incurred.

The Company has a DRIP, whereby holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury or purchased on the market. During the year ended December 31, 2016, the Company issued no common shares from treasury under the DRIP (2015 – 8.7 million).

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

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

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation ("Encana") under the plan of arrangement into two independent energy companies, Encana and Cenovus (pre-arrangement earnings). In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 27A.

	Pre-Arrangement Earnings	**Stock-Based Compensation**	**Total**
As at December 31, 2014	4,086	205	4,291
Stock-Based Compensation Expense	-	39	39
As at December 31, 2015	4,086	244	4,330
Stock-Based Compensation Expense	-	20	20
As at December 31, 2016	**4,086**	**264**	**4,350**

26. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	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	28	587	8	623
Income Tax	(8)	-	(2)	(10)
As at December 31, 2015	(10)	1,014	16	1,020
Other Comprehensive Income (Loss), Before Tax	**(4)**	**(106)**	**(4)**	**(114)**
Income Tax	**1**	**-**	**3**	**4**
As at December 31, 2016	**(13)**	**908**	**15**	**910**

27. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company on or after February 24, 2011 have associated NSRs. The NSRs, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated TSARs. In lieu of exercising the options, the TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The TSARs and NSRs vest and expire under the same terms and conditions as the underlying options.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2016 was $3.77 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**0.72%**
Expected Dividend Yield	**1.01%**
Expected Volatility (1)	**27.82%**
Expected Life (years)	**3.50**

(1) *Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The following tables summarize information related to the NSRs:

As at December 31, 2016	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**42,114**	**31.65**
Granted	**3,646**	**19.54**
Exercised	**-**	**-**
Forfeited	**(4,116)**	**31.76**
Outstanding, End of Year	**41,644**	**30.57**

As at December 31, 2016	**Outstanding NSRs**			**Exercisable NSRs**	
Range of Exercise Price ($)	**Number of NSRs** (thousands)	**Weighted Average Remaining Contractual Life** (years)	**Weighted Average Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
15.00 to 19.99	**3,588**	**6.32**	**19.54**	**1**	**17.93**
20.00 to 24.99	**3,932**	**5.15**	**22.26**	**1,212**	**22.28**
25.00 to 29.99	**12,777**	**4.14**	**28.38**	**7,772**	**28.40**
30.00 to 34.99	**11,194**	**3.18**	**32.62**	**10,868**	**32.63**
35.00 to 39.99	**10,153**	**1.78**	**38.20**	**10,153**	**38.20**
	41,644	**3.59**	**30.57**	**30,006**	**33.00**

TSARs

The Company had a liability of $nil as at December 31, 2016 (2015 – $1 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period-end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.11%**
Expected Dividend Yield	**1.08%**
Expected Volatility [(1)]	**35.19%**
Cenovus's Common Share Price ($)	**20.30**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at December 31, 2016 was $nil (2015 – $nil).

The following tables summarize information related to the TSARs held by Cenovus employees:

As at December 31, 2016	**Number of TSARs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**3,645**	**26.72**
Exercised for Cash Payment	**-**	**-**
Exercised as Options for Common Shares	**-**	**-**
Forfeited	**(272)**	**27.45**
Expired	**-**	**-**
Outstanding, End of Year	**3,373**	**26.66**

As at December 31, 2016	**Outstanding and Exercisable TSARs**		
Range of Exercise Price ($)	**Number of TSARs** (thousands)	**Weighted Average Remaining Contractual Life** (years)	**Weighted Average Exercise Price** ($)
20.00 to 29.99	**3,261**	**0.16**	**26.45**
30.00 to 34.99	**112**	**0.97**	**32.86**
	3,373	**0.19**	**26.66**

The market price of Cenovus's common shares on the TSX as at December 31, 2016 was $20.30.

B) Performance Share Units

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $51 million as at December 31, 2016 (2015 – $49 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares at the end of the year. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at December 31, 2016 and 2015.

The following table summarizes the information related to the PSUs held by Cenovus employees:

As at December 31, 2016	**Number of PSUs** (thousands)
Outstanding, Beginning of Year	**6,427**
Granted	**2,345**
Vested and Paid Out	**(979)**
Cancelled	**(1,697)**
Units in Lieu of Dividends	**61**
Outstanding, End of Year	**6,157**

C) Restricted Share Units

Cenovus has granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole-share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs vest after three years.

RSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair value are recognized as stock-based compensation costs in the period they occur.

The Company has recorded a liability of $30 million as at December 31, 2016 (2015 – $11 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares at the end of the year. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2016 and 2015.

The following table summarizes the information related to the RSUs held by Cenovus employees:

As at December 31, 2016	**Number of RSUs** (thousands)
Outstanding, Beginning of Year	**2,267**
Granted	**1,718**
Vested and Paid Out	**(32)**
Cancelled	**(200)**
Units in Lieu of Dividends	**37**
Outstanding, End of Year	**3,790**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $32 million as at December 31, 2016 (2015 – $26 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares at the end of the year. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

As at December 31, 2016	**Number of DSUs** (thousands)
Outstanding, Beginning of Year	**1,488**
Granted to Directors	**92**
Granted	**11**
Units in Lieu of Dividends	**17**
Redeemed	**(10)**
Outstanding, End of Year	**1,598**

E) Total Stock-Based Compensation

For the years ended December 31,	**2016**	2015	2014
NSRs	**15**	27	41
TSARs	**(1)**	(5)	(10)
PSUs	**13**	(13)	34
RSUs	**13**	6	-
DSUs	**7**	(5)	(5)
Stock-Based Compensation Expense	**47**	10	60
Stock-Based Compensation Costs Capitalized	**12**	6	29
Total Stock-Based Compensation	**59**	16	89

28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2016**	2015	2014
Salaries, Bonuses and Other Short-Term Employee Benefits	**500**	534	550
Defined Contribution Pension Plan	**16**	19	18
Defined Benefit Pension Plan and OPEB	**11**	17	14
Stock-Based Compensation Expense (Note 27)	**47**	10	60
Termination Benefits	**19**	43	-
	593	623	642

29. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	**2016**	2015	2014
Salaries, Director Fees and Short-Term Benefits	**27**	30	29
Post-Employment Benefits	**4**	5	4
Stock-Based Compensation	**4**	5	20
	35	40	53

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recorded during the year associated with stock options, NSRs, TSARs, PSUs, RSUs and DSUs.

30. 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 December 31,	**2016**	2015	2014
Debt	**6,332**	6,525	5,458
Shareholders' Equity	**11,590**	12,391	10,186
	17,922	18,916	15,644
Debt to Capitalization	**35%**	34%	35%
Debt	**6,332**	6,525	5,458
Add (Deduct):			
Cash and Cash Equivalents	**(3,720)**	(4,105)	(883)
Net Debt	**2,612**	2,420	4,575
Shareholders' Equity	**11,590**	12,391	10,186
	14,202	14,811	14,761
Net Debt to Capitalization	**18%**	16%	31%

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

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

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 facility 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 December 31, 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, as defined in the agreement, not to exceed 65 percent. The Company is well below this limit.

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

31. FINANCIAL INSTRUMENTS

Cenovus's 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 December 31, 2016, the carrying value of Cenovus's long-term debt was $6,332 million and the fair value was $6,539 million (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:

As at December 31,	**2016**	2015
Fair Value, Beginning of Year	**42**	32
Acquisition of Investments	**-**	2
Change in Fair Value (1)	**(4)**	8
Impairment Losses (2)	**(3)**	-
Fair Value, End of Year	**35**	42

(1) Changes in fair value on available for sale financial assets are recorded in other comprehensive income.
(2) Impairment losses on available for sale financial assets are reclassified from other comprehensive income to profit or loss.

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 interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2016			2015		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**21**	**307**	**(286)**	301	15	286
Power	**-**	**-**	**-**	-	13	(13)
	21	**307**	**(286)**	301	28	273
Interest Rate	**3**	**8**	**(5)**	-	2	(2)
Total Fair Value	**24**	**315**	**(291)**	301	30	271

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

As at December 31,	**2016**	2015
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(291)**	284
Level 3 – Prices Determined From Unobservable Inputs	**-**	(13)
	(291)	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:

As at December 31,	**2016**	2015
Fair Value of Contracts, Beginning of Year	**271**	462
Fair Value of Contracts Realized During the Year [(1)]	**(211)**	(656)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year [(2)]	**(343)**	461
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(8)**	4
Fair Value of Contracts, End of Year	**(291)**	271

(1) Includes a realized loss of $6 million related to power contracts (2015 – $10 million loss).
(2) Includes an increase of $7 million related to power contracts (2015 – $14 million decrease).

Financial assets and liabilities are offset only if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. No additional unrealized risk management positions are subject to an enforceable master netting arrangement or similar agreement that are not otherwise offset.

The following table provides a summary of the Company's offsetting risk management positions:

	2016			2015		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**75**	**366**	**(291)**	317	46	271
Amount Offset	**(51)**	**(51)**	**-**	(16)	(16)	-
Net Amount per Consolidated Financial Statements	**24**	**315**	**(291)**	301	30	271

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2016, $84 million (2015 – $26 million) was pledged as collateral, of which $18 million (2015 – $5 million) could have been withdrawn.

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

For the years ended December 31,	**2016**	2015	2014
Realized (Gain) Loss [(1)]	**(211)**	(656)	(66)
Unrealized (Gain) Loss [(2)]	**554**	195	(596)
(Gain) Loss on Risk Management	**343**	(461)	(662)

(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.

32. RISK MANAGEMENT

Cenovus 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.

Net Fair Value of Risk Management Positions

As at December 31, 2016	Notional Volumes	Terms	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	10,000 bbls/d	July – December 2017	US$53.09/bbl	**(14)**
Brent Fixed Price	10,000 bbls/d	January – June 2018	US$54.06/bbl	**(11)**
WTI Fixed Price	70,000 bbls/d	January – June 2017	US$46.35/bbl	**(159)**
WTI Collars	50,000 bbls/d	July – December 2017	US$44.84 – US$56.47/bbl	**(52)**
WTI Collars	10,000 bbls/d	January – June 2018	US$45.30 – US$62.77/bbl	**(3)**
Other Financial Positions [1]				**(47)**
Crude Oil Fair Value Position				**(286)**
Interest Rate Swaps				**(5)**
Total Fair Value				**(291)**

(1) 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 fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices or interest rates on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2016	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	**(198)**	**193**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**1**	**(1)**
Interest Rate Swaps	± 50 Basis Points	**45**	**(52)**

As at December 31, 2015	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10.00 per bbl Applied to Brent, WTI and Condensate Hedges	(220)	222
Crude Oil Differential Price	± US$5.00 per bbl Applied to Differential Hedges Tied to Production	80	(80)
Interest Rate Swaps	± 50 Basis Points	38	(46)

A) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps and costless collars to partially mitigate its exposure to the commodity price risk on its crude oil sales. In addition, Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Condensate – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its condensate purchases.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company may enter into swaps, which fix the AECO or the New York Mercantile Exchange ("NYMEX") price. To help protect against widening natural gas price differentials in various production areas, Cenovus may also enter into swaps to manage the price differentials between production areas and various sales points.

B) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

As disclosed in Note 6, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada. As at December 31, 2016, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2015 – US$4,750 million). In respect of these financial instruments, the impact of changes in the U.S. to Canadian dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

For the years ended December 31,	**2016**	2015	2014
$0.01 Increase in the U.S. to Canadian Dollar Foreign Exchange Rate	**48**	48	48
$0.01 Decrease in the U.S. to Canadian Dollar Foreign Exchange Rate	**(48)**	(48)	(48)

C) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. In addition, to manage exposure to interest rate volatility, the Company entered into interest rate swap contracts related to expected future debt issuances. As at December 31, 2016, Cenovus had a notional amount of US$400 million in interest rate swaps.

As at December 31, 2016, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $nil (2015 – $nil, 2014 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee of the Board of Directors designed to ensure that its credit exposures are within an acceptable risk level as determined by the Company's Enterprise Risk Management Policy. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Cenovus's exposure to its counterparties is within credit policy tolerances.

As at December 31, 2016 and 2015, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2016, 90 percent (2015 – 91 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. As at December 31, 2016, Cenovus had three counterparties (2015 – one counterparty) whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, and long-term receivables is the total carrying value.

E) Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 30, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and availability under its shelf prospectuses. As at December 31, 2016, Cenovus had $3.7 billion in cash and cash equivalents, and $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.

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2016	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,266	-	-	-	**2,266**
Risk Management Liabilities (1)	293	22	-	-	**315**
Long-Term Debt (2)	339	2,662	1,150	7,550	**11,701**
Other	-	25	8	16	**49**

As at December 31, 2015	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	1,702	-	-	-	1,702
Risk Management Liabilities (1)	23	5	2	-	30
Long-Term Debt (2)	349	2,847	493	8,721	12,410
Other	-	3	1	4	8

(1) *Risk management liabilities subject to master netting agreements.*
(2) *Principal and interest, including current portion.*

33. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2016**	2015	2014
Interest Paid	**350**	330	335
Interest Received	**32**	19	33
Income Taxes Paid	**11**	933	46

34. COMMITMENTS AND CONTINGENCIES

A) Commitments

Future payments for the Company's commitments are below. A commitment is an enforceable and legally binding agreement to make a payment in the future for the purchase of goods and services. These items exclude amounts recorded in the Consolidated Balance Sheets.

As at December 31, 2016	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	682	711	722	1,031	1,239	21,875	**26,260**
Operating Leases (Building Leases) (2)	101	146	146	145	142	2,465	**3,145**
Product Purchases	70	-	-	-	-	-	**70**
Capital Commitments	23	3	-	-	-	-	**26**
Other Long-Term Commitments	80	27	26	15	15	108	**271**
Total Payments (3)	956	887	894	1,191	1,396	24,448	**29,772**
Fixed Price Product Sales	3	-	-	-	-	-	**3**

As at December 31, 2015	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	702	715	780	774	901	23,537	27,409
Operating Leases (Building Leases) (2)	116	120	156	153	151	2,647	3,343
Product Purchases	84	3	-	-	-	-	87
Capital Commitments	61	14	4	-	-	-	79
Other Long-Term Commitments	45	31	24	26	15	125	266
Total Payments (3)	1,008	883	964	953	1,067	26,309	31,184
Fixed Price Product Sales	55	3	-	-	-	-	58

(1) *Includes transportation commitments of $19 billion (2015 – $19 billion) that are subject to regulatory approval or have been approved but are not yet in service.*
(2) *Excludes committed payment for which a provision has been provided.*
(3) *Contracts undertaken on behalf of FCCL and WRB are reflected at Cenovus's 50 percent interest.*

For the year ended December 31, 2016, the Company's transportation commitments decreased approximately $1.1 billion primarily due to the use of contracts and changes 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 December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (2015 – $64 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 32.

B) Contingencies

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on its Consolidated Financial Statements.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recorded a liability of $1,847 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

Cenovus Energy Inc.

Supplementary Information – Oil and Gas Activities (unaudited)

For the Year Ended December 31, 2016

(Canadian Dollars)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES TOPIC 932 "EXTRACTIVE ACTIVITIES – OIL AND GAS" (unaudited)

The following select disclosures of Cenovus Energy Inc.'s ("Cenovus" or the "Company") reserves and other oil and gas information have been prepared in accordance with United States ("U.S.") Financial Accounting Standards Board ("FASB") Topic 932, "Extractive Activities – Oil & Gas" and the U.S. disclosure requirements of the Securities and Exchange Commission ("SEC").

All amounts pertaining to Cenovus's audited Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Unless otherwise noted, all dollars are in millions of Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

RESERVES DATA

The SEC Modernization of Oil and Gas Reporting final rules require that proved reserves be estimated using existing economic conditions (constant pricing). Cenovus's results have been calculated using the average of the first-day-of-the-month prices for the prior twelve month period. This same twelve month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Cenovus's share of future production from Canadian reserves to be materially different from that presented.

The reserves estimates included in this supplemental information are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable bitumen, crude oil and natural gas reserves and the future net cash flows derived therefrom are based upon a number of variable factors and assumptions, including but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, all of which may vary considerably from actual results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable bitumen, crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Cenovus's actual production, revenues, royalty payments, taxes and development and operating expenditures with respect to its reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made.

Subsequent to December 31, 2016 no major discovery or other favourable or unfavourable event is believed to have caused a material change in the proved reserves as of that date.

The reserves data contained herein is dated February 14, 2017 with an effective date of December 31, 2016.

OIL AND GAS RESERVE INFORMATION

All of Cenovus's reserves are located in Alberta and Saskatchewan, Canada.

Net Proved Reserves (Cenovus Share After Royalties)[1][2][3]
Average Fiscal-Year Prices

	Bitumen (MMbbls)[4]	Crude Oil and Natural Gas Liquids (MMbbls)[4]	Natural Gas (Bcf)[4]
2015			
Beginning of year	1,503	236	820
Revisions and improved recovery	336	(7)	(73)
Extensions and discoveries	164	1	6
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	(18)	(54)
Production	(50)	(22)	(160)
End of year	1,953	190	539
Developed	282	157	538
Undeveloped	1,671	33	1
Total	1,953	190	539
2016			
Beginning of year	**1,953**	**190**	**539**
Revisions and improved recovery	**(128)**	**(45)**	**8**
Extensions and discoveries	**134**	**-**	**-**
Purchase of reserves in place	**-**	**-**	**-**
Sale of reserves in place	**-**	**-**	**-**
Production	**(54)**	**(18)**	**(141)**
End of year	**1,905**	**127**	**406**
Developed	**307**	**115**	**405**
Undeveloped	**1,598**	**12**	**1**
Total	**1,905**	**127**	**406**

(1) Definitions:

(a) "Net" reserves are the remaining reserves attributable to Cenovus, after deduction of estimated royalties and including royalty interests.

(b) "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations, i.e., prices and costs as of the date the estimate is made.

(c) "Developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared to the cost of a new well.

(d) "Undeveloped" reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Estimates of total net proved bitumen, crude oil, natural gas liquids, or natural gas reserves are not filed by Cenovus with any U.S. federal authority or agency other than the SEC.

(3) Natural gas liquids reserves are individually insignificant and have been included with crude oil reserves.

(4) Millions of barrels is abbreviated as MMbbls; Billion cubic feet is abbreviated as Bcf.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

In calculating the standardized measure of discounted future net cash flows, the average of the first-day-of-the-month prices for the prior twelve month period and cost assumptions were applied to Cenovus's annual future production from proved reserves to determine cash inflows. Future production and development costs do not include any cost inflation and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for asset retirement obligations and future income taxes.

Cenovus cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of Cenovus's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to Cenovus's enhancing the netback price of the Company's proprietary production.

Computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves were based on the following average of the first-day-of-the-month benchmark prices for the twelve month period before the end of the year:

	Crude Oil			Natural Gas	
	WTI[1] Cushing Oklahoma (US$/bbl)	WCS[2] (C$/bbl)	Edmonton Par (C$/bbl)	Henry Hub Louisiana (US$/MMBtu)	AECO[3] (C$/MMBtu)
2016	**42.75**	**37.98**	**52.06**	**2.49**	**2.17**
2015	50.28	46.78	59.41	2.58	2.69

(1) WTI is an abbreviation for West Texas Intermediate.
(2) WCS is an abbreviation for Western Canadian Select.
(3) AECO is an abbreviation for Alberta Energy Company Operations.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2016	2015
Future cash inflows	**49,119**	73,219
Less future:		
Production costs	**24,121**	34,339
Development costs	**11,293**	14,626
Decommissioning liability payments	**2,882**	3,706
Income taxes	**1,966**	4,432
Future net cash flows	**8,857**	16,116
Less 10 percent annual discount for estimated timing of cash flows	**5,225**	10,090
Discounted future net cash flows	**3,632**	6,026

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2016	2015
Balance, beginning of year	**6,026**	18,987
Changes resulting from:		
Sales of oil and gas produced during the period	**(1,421)**	(2,054)
Extensions, discoveries and improved recovery, net of related costs	**285**	535
Purchases of proved reserves in place	**-**	-
Sales of proved reserves in place	**-**	(87)
Net change in prices and production costs	**(3,895)**	(20,942)
Revisions to quantity estimates	**(750)**	1,021
Accretion of discount	**746**	2,441
Previously estimated development costs incurred net of change in future development costs	**1,536**	2,636
Asset retirement obligation	**175**	(313)
Other	**58**	(186)
Net change in income taxes	**872**	3,988
Balance, end of year	**3,632**	6,026

OTHER FINANCIAL INFORMATION

Results of Operations

($ millions)	2016	2015
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	**2,031**	2,829
Intersegment sales	**347**	335
	2,378	3,164
Less:		
Operating costs, production and mineral taxes, and accretion of decommissioning liabilities	**1,085**	1,235
Depreciation, depletion and amortization	**1,222**	1,845
Goodwill impairment	**-**	-
Exploration expense	**2**	138
Operating income	**69**	(54)
Income taxes	**19**	(14)
Results of operations	**50**	(40)

Capitalized Costs

($ millions)	2016	2015
Proved oil and gas properties	**32,274**	31,812
Unproved oil and gas properties (1)	**1,585**	1,575
Total capital cost	**33,859**	33,387
Accumulated depreciation, depletion and amortization	**20,396**	19,185
Net capitalized costs	**13,463**	14,202

(1) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($ millions)	2016	2015
Acquisitions		
Unproved	**11**	4
Proved	**-**	-
Total acquisitions	**11**	4
Exploration costs	**35**	66
Development costs	**738**	1,360
Total costs incurred	**784**	1,430

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.1, 99.2, 99.3 and 99.4 to this annual report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant's fiscal year ended December 31, 2016, an evaluation of the effectiveness of the registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (the "Commission") rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the "Report of Management" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2016, filed as part of this annual report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2016, filed as part of this annual report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2016, there was no change in the registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The registrant's board of directors has determined that Colin Taylor, a member of the registrant's audit committee, qualifies as an "audit committee financial expert" (as such term is defined in paragraph (8) of General Instruction B to Form 40-F), and is "independent" as that term is defined in the rules of the New York Stock Exchange.

Code of Ethics.

The registrant has adopted a "code of ethics" (as that term is defined in paragraph (9) of General Instruction B to Form 40-F), entitled the "Code of Business Conduct & Ethics", that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

The Code of Business Conduct & Ethics (the "Code") is available for viewing on the registrant's website at www.cenovus.com, and is available in print to any person without charge, upon request. Requests for copies of the Code should be made by contacting the registrant's Corporate Secretarial Department, Cenovus Energy Inc., 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6. Information on or connected to our website, even if referred to herein, does not constitute part of this annual report on Form 40-F.

Since the adoption of the Code, there have not been any waivers, including implicit waivers, granted from any provision of the Code. There were no amendments to the Code in the fiscal year ended December 31, 2016.

Principal Accountant Fees and Services.

The required disclosure is included under the heading “Audit Committee - External Auditor Service Fees” in the registrant’s Annual Information Form for the fiscal year ended December 31, 2016, filed as part of this annual report on Form 40-F.

Pre-Approval Policies and Procedures and Percentage of Services Approved by Audit Committee.

The required disclosure is included under the heading “Audit Committee - Pre-Approval Policies and Procedures” and “Audit Committee – External Auditor Service Fees” in the registrant’s Annual Information Form for the fiscal year ended December 31, 2016, filed as part of this annual report on Form 40-F. All fees have been pre-approved by the Audit Committee and therefore none of the services therein were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

The registrant does not have any “off-balance sheet arrangements” (as that term is defined in paragraph (11) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading “Liquidity and Capital Resources - Contractual Obligations and Commitments” in the registrant’s Management’s Discussion and Analysis for the fiscal year ended December 31, 2016, filed as part of this annual report on Form 40-F.

Identification of the Audit Committee.

The registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, Steven F. Leer, Wayne G. Thomson and Colin Taylor.

Mine Safety Disclosure.

Not applicable.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

(1) The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: February 16, 2017

CENOVUS ENERGY INC.

By: /s/ Ivor M. Ruste

Name: Ivor M. Ruste

Title: Executive Vice-President & Chief Financial Officer

EXHIBIT INDEX

Exhibits	Documents
99.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
99.3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.5	Consent of PricewaterhouseCoopers LLP
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of GLJ Petroleum Consultants Ltd.
99.8	Statement of Contingent and Prospective Resources

Exhibit 99.1

Certification of Chief Executive Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Brian C. Ferguson, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 16, 2017

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.2

Certification of Chief Financial Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Ivor M. Ruste, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 16, 2017

/s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.3

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40−F for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian C. Ferguson, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 16, 2017

By: /s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer

Exhibit 99.4

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the “Company”) on Form 40−F for the year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ivor M. Ruste, Executive Vice-President & Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 16, 2017

By: /s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer

Exhibit 99.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2016 of Cenovus Energy Inc. of our report dated February 15, 2017, relating to the Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2016 and December 31, 2015 and the Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years in the period ended December 31, 2016 and the related notes and to the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as at December 31, 2016, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165), and Form F-10 (File No. 333-209490) of Cenovus Energy Inc. of our report dated February 15, 2017 referred to above. We also consent to reference to PricewaterhouseCoopers LLP under the heading "Interests of Experts," which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP
Calgary, Alberta
February 16, 2017

Exhibit 99.6

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and reports evaluating (i) a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2016, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2016 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165) and Form F-10 (File No. 333-209490), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ P.A. Welch

P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 16, 2017

Exhibit 99.7

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and report evaluating a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2016 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165) and Form F-10 (File No. 333-209490), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Keith M. Braaten

Keith M. Braaten, P.Eng.
President & CEO

Calgary, Alberta
February 16, 2017

Exhibit 99.8

Cenovus Energy Inc.

Statement of Contingent and Prospective Resources

For the Year Ended December 31, 2016

February 15, 2017

STATEMENT OF CONTINGENT AND PROSPECTIVE RESOURCES

This document contains information relating to estimates of economic bitumen contingent resources and bitumen prospective resources of Cenovus Energy Inc. ("Cenovus" or the "Company") as at December 31, 2016.

Cenovus retained McDaniel & Associates Consultants Ltd. ("McDaniel") to evaluate and prepare reports on the bitumen contingent and prospective resources of the Company. The McDaniel resources evaluations were conducted using petrophysical, geological, and engineering data. Processes and procedures are in place to ensure that McDaniel is in receipt of all relevant information. Contingent and prospective resources were estimated using volumetric calculations to estimate the in-place bitumen quantities, combined with development and performance from analog oil sands reservoirs. The oil sands assets currently producing from the McMurray-Wabiskaw formation including Foster Creek and Christina Lake were used as performance analogs for contingent and prospective resources estimation within these areas. Other regional analogs were used to estimate Cenovus's contingent and prospective resources in the Grand Rapids formation within the Greater Pelican Lake Region, in the McMurray formation at the Telephone Lake property, and in the Clearwater formation at the Foster Creek Region. McDaniel also tested contingent resources for economic viability using McDaniel's January 1, 2017 forecast of prices and inflation, the same forecast which was used to evaluate the Company's reserves (refer to "Pricing Assumptions" in Cenovus's Annual Information Form for the year ended December 31, 2016).

BEST ESTIMATE CONTINGENT AND PROSPECTIVE RESOURCES

	Bitumen			
Company Interest (billions of barrels)	December 31, 2016		December 31, 2015	
Economic Contingent Resources [1]	Before Royalties	After Royalties	Before Royalties	After Royalties
By Project Maturity Subclass:				
Christina Lake	0.6	0.5	0.8	0.6
Foster Creek	0.3	0.2	1.1	0.9
Borealis	1.5	1.3	2.6	2.2
Greater Pelican Lake	1.2	1.0	1.7	1.5
Development pending	3.6	3.0	6.2	5.2
Christina Lake	0.2	0.1	0.0	0.0
Foster Creek	0.8	0.6	0.0	0.0
Borealis	0.9	0.7	0.0	0.0
Greater Pelican Lake	0.3	0.3	0.0	0.0
Development on hold	2.2	1.8	0.0	0.0
Borealis	3.1	2.6	3.1	2.6
Development unclarified	3.1	2.6	3.1	2.6
Economic Contingent Resources	8.8	7.3	9.3	7.8
Prospective Resources [2]				
By Project Maturity Subclass:				
Prospect				
Prospective Resources	7.1	N/A	7.4	N/A

(1) There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.
(2) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not evaluated for economics, so after royalty volumes are not known.

Uncertainty over the timing of oil price recovery has led to delay of some projects, resulting in their being reclassified as development on hold rather than development pending. Best estimate economic contingent resources decreased five percent to 8.8 billion barrels and best estimate prospective resources decreased three percent to 7.1 billion barrels, primarily due to slight recovery factor reductions resulting from revised development plans for portions of Borealis and Greater Pelican Lake to optimize their value.

Cenovus has chosen to not disclose contingent resource volumes which are subject to technology under development, as commercial viability has yet to be established for the recovery of these volumes.

EVALUATION BASIS

The evaluation assumes that the majority of Cenovus's bitumen resources will be recovered and produced using the established technologies of steam assisted gravity drainage ("SAGD") and cyclic steam stimulation ("CSS"), with only a minor portion of the Company's resources likely to be developed using CSS. SAGD involves injecting steam through horizontal wells drilled into the bitumen formation and recovering heated bitumen and water from producing wells located below the injection wells. CSS involves injecting steam into a well and then producing heated bitumen and water from the same wellbore. Such alternating injection and production cycles are repeated a number of times for a given wellbore. Both of these bitumen recovery technologies have a surface footprint comparable to conventional crude oil production operations. Cenovus has no bitumen resources that require mining techniques for recovery.

All of Cenovus's disclosed contingent and prospective resources are associated with clastic or sandstone formations. Cenovus has also identified significant amounts of bitumen on its lands in the Grosmont carbonate formation. Pilot testing of the SAGD recovery process in carbonates has been conducted in the Grosmont carbonate formation several miles away from Cenovus's lands, but commercial viability has yet to be established.

ESTIMATION RISKS

Contingent and prospective resources results are estimates only. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Company's control. In general, estimates of contingent and prospective resources are based upon a number of variable factors and assumptions, including but not limited to: product prices; future operating and capital costs and the assumed effects of regulation by governmental agencies, including royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of crude oil and natural gas gathering systems, pipelines, rail transportation and processing facilities, all of which may vary considerably from actual results. In addition, there are contingencies that prevent resources from being classified as reserves. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. Prospective resources are subject to similar contingencies and are also undiscovered, meaning that subsequent drilling may demonstrate actual results which may vary significantly from projected results. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Actual results may vary significantly from these estimates and such variances could be material.

DEFINITIONS AND CENOVUS'S APPLICATION

The following terminology, consistent with the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and guidance from Canadian securities regulators, was used to prepare the disclosure of contingent and prospective resources:

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

  The McDaniel estimates of contingent resources have not been adjusted for risk based on the chance of development.

- **Economic contingent resources** are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and inflation. Only those bitumen contingent resources based on established technology and determined to be economic using McDaniel's forecast of prices and inflation are disclosed here.

- **Contingencies,** which must be overcome to enable the reclassification of contingent resources as reserves, can be categorized as economic, non-technical and technical. The COGE Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to Cenovus's disclosed economic contingent resources do not include economic contingencies.

  Cenovus's bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis, and Greater Pelican Lake. At Foster Creek and Christina Lake, Cenovus has economic contingent resources located outside the currently approved project areas. Regulatory approval to expand a project area is necessary to enable the reclassification of these economic contingent resources as reserves. The timing of applications for such approvals is dependent on the rate of development drilling, which ties to an orderly development plan to maximize utilization of steam generation facilities and ultimately optimize production, capital utilization and value.

  In the Borealis Region, Cenovus received regulatory approval for a development project at the Telephone Lake property which will help facilitate the reclassification of certain economic contingent resources to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity to submit regulatory applications for development projects. Further stratigraphic test well drilling and seismic activity are required in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

In the Greater Pelican Lake Region, Cenovus received regulatory approval for a development project at the Grand Rapids property. Pilot project work was undertaken to validate technical assumptions and examine optimal development strategies, however, as of February 2016 further activity in respect of the pilot project was deferred in response to the current low commodity price environment. Further reclassification of contingent resources to reserves in the Greater Pelican Lake Region is contingent upon establishing productivity at commercial rates and further regulatory approval for development expansions.

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

- **Best estimate** is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources identified as best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

- **Project maturity** subclasses are subclassifications of reserves, contingent and prospective resources which help identify a project's chance of commerciality. The estimation of reserves and resources must always be done in the context of a project, defined as an activity or set of activities that define the basis for the assessment and classification of reserves and resources. Recognized subclasses for contingent resources include development pending, development on hold, development unclarified, and development not viable. Characteristics of these subclasses are as follows:

  - Development pending: resolution of the final conditions for development is being actively pursued, indicating there is a high chance of development;
  - Development on hold: there are major non-technical contingencies to be resolved that are usually beyond the control of the operator, although there is a reasonable chance of development;
  - Development unclarified: the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties; and
  - Development not viable: no further data acquisition or evaluation is currently planned, resulting in a low chance of development.

  Cenovus's contingent resources located in the Christina Lake and Foster Creek regions are in close proximity to existing production facilities, with capacity scheduled to accommodate the associated production. These projects are subclassified as development pending. Cenovus has received approvals to proceed with development of portions of the Telephone Lake property in the Borealis Region and the Grand Rapids formation in the Greater Pelican Region. These approved projects are also subclassified as development pending. Projects in the remainder of the Borealis Region are still under appraisal and evaluation, and are subclassified as development on hold and development unclarified.

  Contingent resources for projects which are uneconomic and subclassified as development not viable, are not disclosed.

  Subclasses for prospective resources include:
  - Play: a family of geologically similar fields, prospects, discoveries and leads;
  - Lead: a potential accumulation within a play that requires more data acquisition and/or evaluation in order to be called a prospect; and
  - Prospect: a potential accumulation within a play that is sufficiently well defined to represent a viable drilling target.

  All of Cenovus's prospective resources are proximal to existing reserves and/or contingent resources and represent viable drilling targets. They are all subclassified as prospects.

PROJECT CHARACTERIZATION

Cenovus has consolidated its contingent and prospective resources into four regions: Christina Lake, Foster Creek, Borealis, and Greater Pelican Lake. Within these regions there are multiple projects at various levels of advancement. The contingent resources within the Christina Lake and Foster Creek regions are located in areas which are geological extensions of the current SAGD development, and are expected to be developed in sequence as existing development expands out to those areas.

Within the Borealis Region there are also several projects, with only Telephone Lake being the subject of active development planning. An initial development project has received Alberta Energy Regulator ("AER") approval, with future extension projects undergoing evaluation. Additional projects in the Borealis Region have been identified, but there is insufficient data to construct well-defined development plans. Tentative plans have been evaluated, however, additional data may lead to significant variation of these plans.

Within the Greater Pelican Lake Region, a development plan has also been approved by the AER, leading to recognition of probable reserves within the approved development area. The contingent resources are an extension of the probable reserves, but are contingent on establishing satisfactory reservoir productivity. A pilot project to address productivity was underway, however, as of February 2016 further activity has been deferred in response to the current low commodity price environment.

The following table summarizes the project maturity sub-classes in each of the regional areas.

Region	Project Maturity Subclass	Evaluation Scenario Status	Capital to reach Commercial Production (1) $MM	Timing of First Commercial Production	Recovery Technology (Established)
Christina Lake	Development pending	Development/ Pre-development	190 – 630	2023 – 2049	SAGD
	Development on hold	Pre-development	380 – 630	2031	SAGD
Foster Creek	Development pending	Development/ Pre-development	80 – 1,260	2025 – 2031	SAGD
	Development on hold	Pre-development	210 – 990	2026 – 2035	SAGD/CSS
Borealis	Development pending/ Development on hold	Development	2,100	2024	SAGD
	Development unclarified	Conceptual	900 – 2,100	2025 – 2029	SAGD
Greater Pelican Lake	Development pending/ Development on hold	Pre-development	2,100	2025	SAGD

(1) McDaniel capital incorporates 2% per year inflation.

The range of timing indicated for first production and cost to achieve commercial production reflects the range of projects identified in each region, and is a function of the relative priority placed on extending the reach of the existing development out to those projects. Project timing is also a function of the availability of capital to commence development activity. Capital to reach commercial production shown in the table above is primarily for infrastructure and facilities development, and does not include the significant amount of sustaining capital required to drill additional SAGD well pairs within each project to sustain production at project design rates.

The Telephone Lake and Grand Rapids projects are stand-alone, greenfield developments. These projects have received regulatory approval to proceed, with continuing delineation, engineering work and infrastructure development underway, although as of February 2016 further activity in respect of the SAGD pilot at Grand Rapids has been deferred in response to the current low commodity price environment. Reservoir knowledge gained from existing operations is continually being reviewed for its potential impact on the optimization of these new developments. Typically, the timing of first commercial production from receipt of regulatory approval is five to eight years.

The uncertain timing of when technologies under development will become established, such as SAGD in carbonates and fireflooding in clastic bitumen deposits, and the uncertain timing of when economic viability might be established has led Cenovus to disclose only those contingent resources whose development is pending, on hold, or unclarified, which are economically viable, and which are not subject to technology under development.

RESERVES AND RESOURCES RECONCILIATION

The systematic progression of Cenovus's bitumen resources, from prospective to contingent resources and then to reserves, and ultimately to production, was deliberately slowed in 2016 as low commodity prices limited availability of delineation capital. For example, most stratigraphic wells drilled in 2016 were focused on supporting conversion of reserves to production at Christina Lake and Foster Creek, resulting in negligible contingent and prospective resources reclassification. Revised development plans resulted in slight recovery factor reductions for portions of the Borealis and Greater Pelican Lake Regions to optimize their value , resulting in slight reductions in bitumen best estimate economic contingent resources and prospective resources for 2016.

An annual reconciliation of reclassifications is shown in the following table:

Bitumen Proved plus Probable Reserves, Contingent and Prospective Resources Reconciliation and Category Movements

Company Interest Before Royalties (billions of barrels)	**Proved plus Probable Reserves**	**Best Estimate Economic Contingent Resources [1]**	**Best Estimate Prospective Resources [2]**
As at December 31, 2015	3.298	9.3	7.4
Transfers between Categories	0	0	0
Additions from Other Resources Categories	0	0	0
Reductions to Other Resources Categories	0	0	0
Additions and Revisions Net of Transfers	0.076	-0.5	-0.3
Net Acquisitions and Divestitures	0	0	0
Production	-0.055	0	0
As at December 31, 2016	3.319	8.8	7.1

(1) There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

(2) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.