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, 2015 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. 333-196696).

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, 2015.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2015.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2015.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2015.

Cenovus Energy Inc.

Annual Information Form

For the Year Ended December 31, 2015

February 10, 2016

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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; projected future value; projections for 2016 and future years; forecast operating and financial results; planned capital expenditures, including the timing and financing thereof; 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 expected impacts to Cenovus; future use and development of technology, including expected effects on environmental impact; and projected shareholder return. 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 flow from operations 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 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, 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 at sedar.com, 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 amalgamated with its wholly owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Alberta Court of Queen's Bench. On July 31, 2015 Cenovus amalgamated with its wholly owned subsidiary, 9281584 Canada Limited (formerly 1528419 Alberta Ltd.), by way of a vertical short-form amalgamation.

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.

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, 2015 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 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, 2015 and (ii) less than 10 percent of the Corporation's consolidated revenues for the year ended December 31, 2015. 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, 2015.

GENERAL DEVELOPMENT OF THE BUSINESS

OVERVIEW

Cenovus is a Canadian 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, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations 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, 2015, Cenovus had a land base of approximately 5.6 million net acres. The estimated proved reserves life index based on working interest production as at December 31, 2015 was approximately 25 years.

BUSINESS SEGMENTS

The Corporation's reportable segments are as follows:

Oil Sands	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	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	Includes 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	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.

(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.

(2) For the purpose of this AIF, references to "natural gas" means "conventional natural gas" as defined in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

(3) For the purpose of this AIF, references to "heavy oil" means "heavy crude oil" as defined in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

THREE YEAR HISTORY

The following describes significant events that have influenced the development of the business during the last three financial years and year to date in 2016:

2013

- **Oil Sands regulatory applications.** In the first quarter, Cenovus submitted regulatory applications and environmental impact assessments ("EIAs") for Christina Lake phase H and Foster Creek phase J, with approved gross production capacity of 50,000 barrels per day from each phase.

- **First production at Christina Lake phase E.** In the third quarter, phase E of Christina Lake achieved first production, with gross production capacity of 40,000 barrels per day.

- **Regulatory approval for Christina Lake optimization.** In the third quarter, Cenovus received regulatory approval for the optimization program at Christina Lake phases C, D and E, with approved incremental gross production capacity of 22,000 barrels per day.

- **Construction at Narrows Lake phase A initiated.** In the third quarter, construction of the Narrows Lake phase A plant was initiated with expected gross production capacity of 45,000 barrels per day.

- **Public debt offering completed.** In the third quarter, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$450 million with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043, for an aggregate amount of US$800 million. The net proceeds of the offering were used to partially fund the early redemption of the Corporation's US$800 million senior unsecured notes due September 2014.

- **Divestiture of non-core asset.** In the third quarter, Cenovus sold its Lower Shaunavon asset to an unrelated third party for net proceeds of approximately $241 million.

- **Increased rail takeaway capacity.** In the fourth quarter, Cenovus increased its rail takeaway capacity to 10,000 barrels per day.

- **Telephone Lake dewatering pilot completed.** In the fourth quarter, the Telephone Lake dewatering pilot was successfully completed. Cenovus effectively displaced water with compressed air, removing approximately 70 percent of below-ground non-potable top water.

- **Receipt of Partnership contribution receivable.** In the fourth quarter, Cenovus received US$1.4 billion from ConocoPhillips, the Corporation's partner in FCCL, representing the remaining principal and interest due under the Partnership Contribution Receivable through the Corporation's interest in FCCL.

- **Foster Creek optimization update**. Timing of optimization work for Foster Creek phases F, G and H was reassessed as part of Cenovus's long-term reservoir management plan. Expected total gross production capacity from these three phases, including optimization, remained up to 125,000 barrels per day.

2014

- **Regulatory approval received for Grand Rapids.** In the first quarter, Cenovus received regulatory approval for its Grand Rapids 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 Refining LP, 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 is expected to add 30,000 barrels per day of gross production capacity.

- **Increased rail takeaway capacity.** In the fourth quarter, Cenovus increased its 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, Cenovus received permit approval for the Wood River Refinery debottlenecking project. Start-up of the project is anticipated in the third quarter of 2016.

- **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 a Gross Overriding Royalty ("GORR") on Cenovus's Pelican Lake heavy oil property in northern Alberta and its EOR project located near 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 general and administrative costs. The cost reductions apply across the Corporation and include 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 positions, 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 positions than it had at December 31, 2014.

- **Completed Christina Lake optimization.** In the fourth quarter, the Christina Lake optimization program began steam circulation, and is expected to add up to 22,000 barrels per day gross incremental production capacity and ramp up over the next 12 months, 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

- **Capital spending.** Cenovus expects that the commodity price environment will continue to influence the general development of its business in 2016. The Corporation will continue to assess its plans in light of the commodity price environment and other relevant factors and will make adjustments to its capital spending and other business activities as appropriate.

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 our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, helping the Corporation to minimize costs.

New Technology

Focused technology development, research activities and understanding environmental impact play increasingly larger roles in all aspects of Cenovus's business. Cenovus continues to seek new technologies and is actively developing its own technologies with the goal of increasing recoveries from its reservoirs, while reducing the amount of water, natural gas and electricity consumed in its operations, potentially reducing costs and minimizing the Corporation's environmental footprint.

Landholdings

As at December 31, 2015, Cenovus held bitumen rights of approximately 1.8 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 net 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, 2015, 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	4	49	24	58	28	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	383	345	448	380	831	725	87%
Other	29	11	1,459	1,173	1,488	1,184	79%
Total	453	384	2,300	1,850	2,753	2,234	81%

(1) Percentages as 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:

	Bitumen (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
(annual average)	**2015**	2014	**2015**	2014	**2015**	2014
Foster Creek	**65,345**	59,172	**-**	-	**65,345**	59,172
Christina Lake	**74,975**	69,023	**-**	-	**74,975**	69,023
Athabasca (1)	**-**	-	**19**	22	**3,167**	3,667
Total	**140,320**	128,195	**19**	22	**143,487**	131,862

(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, 2015. These figures exclude wells which were capable of producing, but that were not producing as at December 31, 2015:

	Producing Bitumen Wells		Producing Gas Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Foster Creek	255	128	-	-	255	128
Christina Lake	151	76	-	-	151	76
Grand Rapids	2	2	-	-	2	2
Athabasca	-	-	316	303	316	303
Other	3	3	-	-	3	3
Total	411	209	316	303	727	512

Foster Creek

Cenovus has a 50 percent working interest in Foster Creek, Cenovus's first commercial steam-assisted gravity drainage ("SAGD") operation. 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 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 F at Foster Creek averaged 65,345 barrels per day in 2015. Plant construction at phase G is nearing completion with first production anticipated in the third quarter of 2016. Phase G is expected to add additional production capacity of 30,000 gross barrels per day. Expansion work on phase H has been deferred in response to the current low commodity price environment.

Cenovus operates an 80 megawatt natural gas-fired cogeneration facility in conjunction with the SAGD operation at 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 E at Christina Lake averaged 74,975 barrels per day in 2015. Optimization was completed in the fourth quarter of 2015, and is expected to add approximately 22,000 barrels per day gross production once fully ramped up in 12 months. Expansion work at phase F (including cogeneration) is nearing completion, with first oil expected in the third quarter of 2016. Phase F is anticipated to add production capacity of 50,000 gross barrels per day. Expansion work on phase G has been deferred in response to the current low commodity price environment.

Cenovus received regulatory approval for phase H in the fourth quarter of 2015, a 50,000 gross barrel per day phase.

Several innovations to SAGD technology have been undertaken at Christina Lake over the past several years. One major innovation is solvent aided process technology ("SAP"). SAP is a new enhancement to SAGD expected to reduce environmental impact. SAP involves injecting a solvent together with the steam. SAP is expected to require less steam, which will reduce greenhouse gas emissions and water usage per barrel of oil and increase oil production and oil recovery rates. Various embodiments of SAP related technology are currently being piloted at Christina Lake. Based on results from the various SAP related pilots, Cenovus plans to commercialize the SAP technology with phase A of its Narrows Lake project.

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. The solvent to be used at Narrows Lake is expected to be butane, which is already present in the reservoir in small amounts.

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 current low commodity price environment, Cenovus has suspended new construction spending on phase A. The future development of Narrows Lake should 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.

In 2015, Cenovus continued to advance development plans for Telephone Lake after receiving approval from the Alberta Energy Regulator ("AER") in late 2014 for an initial 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 steam to oil ratio.

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 current 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 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.

Cenovus completed a pilot program using a helicopter and an experimental lightweight drilling rig, referred to as SkyStrat™, to drill stratigraphic test wells. The SkyStrat™ drilling rig is a rig that was developed to improve stratigraphic drilling programs in the oil sands. Transporting the rig by helicopter allows Cenovus to access remote exploratory drilling locations year-round and eliminates the need for temporary roads, significantly reducing the surface footprint and potentially reducing water use for the drilling operations by over 50 percent. The Corporation completed construction on a second SkyStrat™ drilling rig in the fourth quarter of 2014. A total of seven stratigraphic wells were drilled using SkyStrat™ drilling technology in 2015.

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 14 million cubic feet per day in 2015 (2014 - 15 million cubic feet per day). The Alberta Department of Energy has provided a ten year royalty credit which can equal up to 50 percent of lost cash flow to help offset the impact of the shut-in wells. This royalty credit fluctuates with the price of natural gas.

Capital Investment

In 2015, the Corporation's Oil Sands capital investment was $1.2 billion, primarily related to the expansions at Foster Creek and Christina Lake. The production capacity for these projects is expected to increase to approximately 390,000 gross barrels per day with completion of Foster Creek phase G and Christina Lake phase F. Ramp up to total production for these phases is expected to extend into 2017.

- Capital at Foster Creek was focused on sustaining capital related to existing production, 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, expansion phases F and G, and the optimization project. The optimization project has been completed and is expected to add approximately 22,000 barrels per day of gross production capacity, with incremental oil production expected to ramp up over a period of twelve months.
- Capital at Narrows Lake was focused on detailed engineering and construction wind-down.
- Capital at Telephone Lake was focused on front end engineering work on the central processing facility and preliminary infrastructure development.

- Capital at Grand Rapids was focused on continued operation of the SAGD pilot project and a third well pair commenced steam circulation.

Due to the lower crude oil price environment, 2016 capital spending is planned to be focused on completion of the Foster Creek phase G and Christina Lake phase F (including cogeneration) expansions. Funding is also planned to maintain current production levels from existing oil sands phases as well as meeting all maintenance, safety, regulatory and contractual obligations.

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 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 approximately $3.3 billion. Production from fee lands had comprised approximately 50 percent of the Corporation's total conventional production in 2014. Associated third-party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day. Where Cenovus had current working interest production on these fee lands, the Corporation entered into lease agreements with HRP. A GORR on Cenovus's production from its Pelican Lake and Weyburn assets was included as part of the sale. 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 to select leases on half of the remaining undeveloped acreage.

Conventional operations also include leases of Crown lands primarily in the Suffield area 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]	959	920	32	27	991	947	96%
Suffield	935	923	89	89	1,024	1,012	99%
Langevin [3]	669	651	63	55	732	706	96%
Pelican Lake [4]	95	94	254	241	349	335	96%
Wainwright	49	29	13	9	62	38	63%
Other	24	15	149	135	173	150	87%
Saskatchewan							
Weyburn	48	36	51	41	99	77	78%
Bakken	4	4	48	48	52	52	98%
Total	2,783	2,672	699	645	3,482	3,317	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.
(4) Overlapping landholdings between Grand Rapids (included in the Oil Sands segment) and Pelican Lake 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 [1] for the periods indicated:

	Crude Oil and NGLs (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
(annual average)	**2015**	2014	**2015**	2014	**2015**	2014
Alberta						
Grassland [2]	**7,248**	8,923	**212**	232	**42,581**	47,590
Suffield	**8,854**	10,010	**125**	135	**29,687**	32,510
Langevin [3]	**8,025**	9,368	**84**	96	**22,025**	25,368
Pelican Lake	**24,421**	24,924	**-**	-	**24,421**	24,924
Wainwright [4]	**1,638**	4,687	**1**	2	**1,805**	5,020
Other	**10**	8	**-**	-	**10**	8
Saskatchewan						
Weyburn	**15,732**	16,196	**-**	-	**15,732**	16,196
Bakken [4]	**699**	1,182	**-**	1	**699**	1,349
Other	**-**	-	**-**	-	**-**	-
Total	**66,627**	75,298	**422**	466	**136,960**	152,965

(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.
(4) Cenovus sold certain interests in its Bakken and Wainwright crude oil assets in the second and third quarter of 2014, respectively. Cenovus retained royalty interests on mineral fee title lands in these areas. In the third quarter of 2015, Cenovus sold those royalty interests.

Producing Wells

The following table summarizes Cenovus's interests in producing wells [1] as at December 31, 2015. These figures exclude wells which were capable of producing, but that were not producing, as at December 31, 2015:

	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Alberta						
Grassland [2]	398	391	8,804	8,660	9,202	9,051
Suffield	739	739	10,676	10,658	11,415	11,397
Langevin [3]	300	298	4,752	4,740	5,052	5,038
Pelican Lake	587	587	1	1	588	588
Wainwright	57	52	10	2	67	54
Other	10	5	2	1	12	6
Saskatchewan						
Weyburn	644	405	-	-	644	405
Bakken	9	2	-	-	9	2
Other	1	1			1	1
Total	2,745	2,480	24,245	24,062	26,990	26,542

(1) Includes wells on mineral fee title lands where Cenovus has a working interest. Excludes wells on mineral fee title lands where Cenovus only has 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.

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, 2015, approximately 64 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 27 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 southwestern Saskatchewan, Cenovus has a 62.1 percent working interest. However, after taking into consideration a net royalty interest obligation to a third party, 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 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	
	2015	2014	**2015**	2014	**2015**	2014
Alberta						
Grassland [3]	**15**	42	**6,632**	8,224	**-**	-
Suffield	**1**	18	**-**	-	**8,837**	9,991
Langevin [4]	**12**	29	**7,858**	9,221	**-**	-
Wainwright [5]	**-**	4	**1**	42	**1,630**	4,631
Pelican Lake	**-**	25	**-**	-	**24,421**	24,924
Other	**-**	1	**10**	8	**-**	-
Saskatchewan						
Weyburn	**6**	7	**15,343**	15,921	**-**	-
Bakken [5]	**-**	-	**642**	1,115	**-**	-
Other	**-**	-	**-**	-	**-**	-
Total	**34**	126	**30,486**	34,531	**34,888**	39,546

(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.
(5) Cenovus sold certain interests in its Bakken and Wainwright crude oil assets in the second and third quarter of 2014, respectively. Cenovus retained royalty interests on mineral fee title lands in these areas. In the third quarter of 2015, Cenovus sold those royalty interests.

Conventional Gas Assets

Cenovus holds natural gas interests in multiple zones in the Suffield, Grassland and Langevin areas in Alberta. Development in these areas focuses 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 both its oil sands and refining operations.

In 2015, Conventional natural gas production averaged 422 MMcf per day (2014 – 466 MMcf per day). Cenovus did not drill any gas wells in 2015 or 2014.

Capital Investment

In 2015, the Corporation's Conventional capital investment was $244 million, primarily related to modest drilling activity at our tight oil projects in southeast Alberta and at our CO_2 EOR project at Weyburn. Spending on natural gas activities was allocated to a small number of higher return opportunities.

REFINING AND MARKETING

The Refining and Marketing segment is responsible for refining crude oil into petroleum and chemical products and coordinates Cenovus's marketing and transportation initiatives to optimize the value received for its products.

Refining

Cenovus's refining operations allow it to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American crude oil 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 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 Corporation's 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]	2015	2014
Crude Oil Capacity (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**419**	423
Heavy Oil	**200**	199
Light & Medium Oil	**219**	224
Crude Utilization (%)	**91**	92
Refined Products (Mbbls/d)		
Gasoline	**228**	231
Distillates	**137**	137
Other	**79**	77
Total	**444**	445

(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 the 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 is a major supplier of jet fuel to Lambert International Airport in St. Louis and O'Hare International Airport in Chicago.

The Wood River Refinery's stated crude oil processing capacity for 2014 was 314,000 gross barrels per day, and is unchanged for 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. Heavy crude oil processing capacity is planned to increase approximately another 18,000 gross barrels per day in 2016 with the completion of the debottlenecking project; anticipated to start up in the third quarter of 2016. In 2015, 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 total acid number 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 2014 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 for 2015.

Marketing

Cenovus's marketing activities are focused on enhancing the netback price of the Corporation's 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 crude oil marketing activities are focused on sale of production and management of condensate supply, inventory and storage to meet diluent requirements. Cenovus also manages the marketing of its natural gas, which is primarily sold to industrials, other producers and energy marketing companies. Prices Cenovus receives are based primarily on prevailing index prices for natural gas. Prices are impacted by competing fuels and by North American regional supply and demand for natural gas.

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, 2015.

Transportation

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. As at December 31, 2015, Cenovus has entered into various firm transportation and storage commitments totaling $27 billion, most of which relate to pipelines that are subject to regulatory approval. 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. In the third quarter of 2015, we acquired a crude-by-rail terminal for $75 million, plus adjustments, located at Bruderheim, Alberta as part of our transportation strategy. The terminal has takeaway capacity of 77,000 barrels per day and is operated for Cenovus by a third party contractor.

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 National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("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") 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 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 10, 2016, with an effective date of December 31, 2015. McDaniel's preparation date of the information is January 11, 2016, and GLJ's preparation date is January 4, 2016.

(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 National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

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, general and administrative expenses or the impact of any hedging activities. Future net revenues have been presented on a before and after income tax basis.

Summary of Company Interest Oil and Gas Reserves as at December 31, 2015

(Forecast prices and inflation)

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	268	103	89	703
Developed Non-Producing	54	1	2	14
Undeveloped	1,861	29	19	4
Proved Reserves	2,183	133	110	721
Probable Reserves	1,115	87	44	232
Proved plus Probable Reserves	3,298	220	154	953

After Royalties (1)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	223	84	69	658
Developed Non-Producing	43	1	1	13
Undeveloped	1,428	25	16	3
Proved Reserves	1,694	110	86	674
Probable Reserves	862	67	33	206
Proved plus Probable Reserves	2,556	177	119	880

(1) *As a result of Cenovus's sale in 2015 of HRP, Cenovus's royalty interest and mineral fee title lands business, Cenovus no longer discloses royalty interest reserves separately.*

Summary of Net Present Value of Future Net Revenue as at December 31, 2015 (1)

(Forecast prices and inflation)

Before Income Taxes	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%	Unit Value Discounted at 10% (2) $/BOE
Proved Reserves						
Developed Producing	4,868	6,453	5,992	5,361	4,798	12.34
Developed Non-Producing	1,308	993	776	622	509	16.40
Undeveloped	50,517	20,376	9,538	4,917	2,657	6.49
Proved Reserves	56,693	27,822	16,306	10,900	7,964	8.15
Probable Reserves	35,624	12,105	5,260	2,763	1,642	5.28
Proved plus Probable Reserves	92,317	39,927	21,566	13,663	9,606	7.19

After Income Taxes (3)	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	3,455	5,358	5,110	4,637	4,192
Developed Non-Producing	939	734	588	481	401
Undeveloped	36,922	15,077	7,110	3,685	2,002
Proved Reserves	41,316	21,169	12,808	8,803	6,595
Probable Reserves	26,583	9,021	3,900	2,038	1,208
Proved plus Probable Reserves	67,899	30,190	16,708	10,841	7,803

(1) *Due to amendments to NI 51-101 effective July 1, 2015 (the "2015 Amendments"), abandonment and reclamation costs included in the calculation of the NPV and FNR for 2015 are different than abandonment and reclamation costs included in Cenovus's 2014 disclosure of NPV and FNR. The 2015 Amendments require that all abandonment and reclamation costs be included in the calculation of NPV and FNR including all existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.*

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

(3) *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, 2015.*

Total Future Net Revenue (undiscounted) as at December 31, 2015
(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	176,710	40,459	51,293	19,671	8,594	56,693	15,377	41,316
Proved plus Probable Reserves	282,430	65,067	80,663	34,178	10,205	92,317	24,418	67,899

(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, 2015
(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	14,288	8.44
	Heavy Oil	1,057	9.64
	Light & Medium Oil and NGLs	1,146	13.37
	Natural Gas	(185)	(1.65)
	Total	16,306	8.15
Proved plus Probable Reserves	Bitumen	18,146	7.10
	Heavy Oil	1,684	9.54
	Light & Medium Oil and NGLs	1,699	14.27
	Natural Gas	37	0.25
	Total	21,566	7.19

(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 gas with natural gas, as the reserves of each are not material relative to the other reported product types.
- Numbers presented may be rounded and tables may not add correctly due to rounding.
- Due to amendments to NI 51-101 effective July 1, 2015 (the "2015 Amendments"), abandonment and reclamation costs included in the calculation of the NPV and FNR for 2015 are different than abandonment and reclamation costs included in Cenovus's 2014 disclosure of NPV and FNR. In accordance with the 2015 Amendments, 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.
2. **Before Royalties** means volumes before deduction of royalties and excludes Royalty Interest reserves.
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 the Corporation 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 the Corporation'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 shall be disclosed.

   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:
     - **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.
     - **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, 2016. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs. For historical prices realized during 2015, 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$/C$)
2016	45.00	56.60	52.60	40.50	46.40	2.70	0.0	0.730
2017	53.60	66.40	61.80	47.50	54.40	3.20	2.0	0.750
2018	62.40	72.80	67.70	52.10	59.70	3.55	2.0	0.800
2019	69.00	80.90	75.20	57.80	66.30	3.85	2.0	0.800
2020	73.10	83.20	77.40	59.50	68.20	3.95	2.0	0.825
2021	77.30	88.20	82.00	63.10	72.30	4.20	2.0	0.825
2022	81.60	93.30	86.80	66.70	76.50	4.45	2.0	0.825
2023	86.20	98.70	91.80	70.60	80.90	4.70	2.0	0.825
2024	87.90	100.70	93.70	72.00	82.60	4.80	2.0	0.825
2025	89.60	102.60	95.40	73.40	84.10	4.90	2.0	0.825
2026	91.40	104.70	97.40	74.90	85.90	5.00	2.0	0.825
There -after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.825

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)	2016	2017	2018	2019	2020	Remainder	Total
Proved Reserves	534	980	860	1,073	934	15,290	19,671
Proved plus Probable Reserves	593	1,308	1,378	1,445	1,103	28,351	34,178

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, 2015, 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, 2014	1,970	156	120	796
Extensions and Improved Recovery	188	-	1	8
Discoveries	-	-	-	-
Technical Revisions	76	(10)	1	79
Economic Factors	-	-	(1)	(1)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production [(1)]	(51)	(13)	(11)	(161)
As at December 31, 2015	2,183	133	110	721

Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2014	1,330	123	46	260
Extensions and Improved Recovery	-	-	1	7
Discoveries	-	-	-	-
Technical Revisions	(215)	(36)	(4)	(36)
Economic Factors	-	-	1	1
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production [(1)]	-	-	-	-
As at December 31, 2015	1,115	87	44	232

Proved plus Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2014	3,300	279	166	1,056
Extensions and Improved Recovery	188	-	2	15
Discoveries	-	-	-	-
Technical Revisions	(139)	(46)	(3)	43
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production [(1)]	(51)	(13)	(11)	(161)
As at December 31, 2015	3,298	220	154	953

(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 11 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 were virtually unchanged.

Heavy oil proved reserves decreased by approximately 15 percent primarily as a result of production and drilling deferrals, and the loss of undeveloped reserves at Elk Point as a result of failing to meet economic criteria. Heavy oil probable reserves decreased by approximately 29 percent due to drilling deferrals at Pelican Lake. Overall, heavy oil proved plus probable reserves decreased by approximately 21 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. Light and medium oil and NGLs probable reserves decreased by approximately four percent partly as a result of the conversion of probable reserves to proved reserves. Overall, light and medium oil and NGLs proved plus probable reserves decreased seven percent, primarily as a result of production.

Natural gas and CBM proved reserves declined by approximately nine 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 11 percent and ten percent, respectively.

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	1,717	1,532	93	61	56	22	300	6
2013	158	1,629	1	47	3	15	-	4
2014	161	1,732	7	40	11	21	4	4
2015	238	1,861	-	29	1	19	1	4

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	1,099	646	66	42	34	24	54	16
2013	145	649	56	86	1	17	-	16
2014	649	1,293	5	76	8	15	7	11
2015	1	1,074	-	52	1	14	2	8

DEVELOPMENT OF PROVED AND PROBABLE UNDEVELOPED RESERVES

Bitumen

At the end of 2015, Cenovus had proved undeveloped bitumen reserves of 1,861 million barrels Before Royalties, or approximately 85 percent of the Corporation's proved bitumen reserves. Of Cenovus's 1,115 million barrels of probable bitumen reserves, 1,074 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 formations, such as the 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 not located within an approved development plan 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 45 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 four 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, one 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, 2015:

	Oil		Gas		Total	
Producing Wells (1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	411	209	316	303	727	512
Conventional	2,091	2,072	24,245	24,062	26,336	26,134
Total Alberta	2,502	2,281	24,561	24,365	27,063	26,646
Saskatchewan	654	408	-	-	654	408
Total	3,156	2,689	24,561	24,365	27,717	27,054

(1) Includes wells containing multiple completions as follows: 22,174 gross gas wells (22,013 net wells) and 1,318 gross oil wells (1,073 net wells).

	Oil		Gas		Total	
Non-Producing Wells (1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	61	33	343	246	404	279
Conventional	785	769	971	940	1,756	1,709
Total Alberta	846	802	1,314	1,186	2,160	1,988
Saskatchewan	205	92	5	5	210	97
Total	1,051	894	1,319	1,191	2,370	2,085

(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 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 2015 [(1)]:

Development Wells Drilled	Oil Sands Gross	Oil Sands Net	Conventional Gross	Conventional Net	Total Gross	Total Net
Oil	96	49	35	32	131	81
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	1	1	1	1
Total Working Interest	96	49	36	33	132	82
Royalty	-	-	1	-	1	-
Total Canada	96	49	37	33	133	82

(1) Cenovus did not have any participation or interest in any exploration wells in 2015.

During the year ended December 31, 2015, Oil Sands drilled 164 gross stratigraphic test wells (73 net wells) and Conventional drilled 13 gross stratigraphic test wells (13 net wells).

During the year ended December 31, 2015, Oil Sands drilled eight gross service wells (four net wells) and Conventional drilled three gross service wells (1.8 net wells). 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.

Interest in Material Properties

The following table summarizes Cenovus's landholdings as at December 31, 2015:

Landholdings (thousands of acres)	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage [(1)] Gross	Undeveloped Acreage [(1)] Net	Total Acreage Gross	Total Acreage Net
Alberta:						
Oil Sands						
– Crown [(2)]	453	384	2,236	1,786	2,689	2,170
Conventional						
– Crown [(2)]	1,065	1,019	530	490	1,595	1,509
– Freehold [(3)]	1,666	1,613	70	66	1,736	1,679
Total Alberta	3,184	3,016	2,836	2,342	6,020	5,358
Saskatchewan:						
Oil Sands						
– Crown [(2)]	-	-	64	64	64	64
Conventional						
– Crown [(2)]	35	28	95	87	130	115
– Freehold [(3)]	17	12	4	2	21	14
Total Saskatchewan	52	40	163	153	215	193
Total	3,236	3,056	2,999	2,495	6,235	5,551

(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.
(2) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which Cenovus holds a working interest.
(3) Freehold lands are those lands owned by individuals and other entities (other than a government) in which Cenovus holds a working interest.

Properties With No Attributed Reserves

Cenovus has approximately 4.1 million gross acres (3.6 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 102,000 net acres that could potentially expire by December 31, 2016, 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 $6.5 billion (approximately $1.3 billion, discounted at 10 percent) at December 31, 2015, of which the Corporation expects to pay between $210 million and $260 million in the next three financial years on a portion of the 34,557 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Cenovus's proved reserves, approximately $8.6 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 2016, Cenovus expects to incur losses for income tax purposes and recover income taxes paid in prior years.

Costs Incurred

($ millions)	2015
Acquisitions	
Unproved	4
Proved	-
Total Acquisitions	4
Exploration Costs	66
Development Costs	1,360
Total Costs Incurred	1,430

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, 2015.

Production Estimates

The following table summarizes the estimated 2016 average daily volume of Company Working Interest Before Royalties reflected in the reserves reports for all properties held on December 31, 2015 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.

2016 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d) (1)	152,517	159,881
Light and Medium Oil (bbls/d)	28,265	32,060
Heavy Oil (bbls/d)	31,727	32,946
Natural Gas (MMcf/d)	357	390
Natural Gas Liquids (bbls/d)	658	732
Company Working Interest Before Royalties (BOE/d)	272,715	290,620

(1) Includes Foster Creek production of 74,929 barrels per day for proved and 77,581 barrels per day for proved plus probable, and Christina Lake production of 77,588 barrels per day for proved and 82,300 barrels per day for proved plus probable.

Production History

Average Working Interest Daily Production Volumes - 2015

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	65,345	63,680	71,414	58,363	67,901
Christina Lake (Bitumen)	74,975	75,733	75,329	72,371	76,471
	140,320	139,413	146,743	130,734	144,372
Conventional Liquids					
Heavy Oil	34,260	32,363	33,693	34,790	36,244
Light and Medium Oil	28,607	26,576	27,551	28,886	31,481
Natural Gas Liquids (1)	1,148	1,154	1,130	1,139	1,171
Total Crude Oil and Natural Gas Liquids	204,335	199,506	209,117	195,549	213,268
Natural Gas (MMcf/d)					
Oil Sands	19	19	19	21	20
Conventional	412	405	405	415	423
Total Natural Gas	431	424	424	436	443
Total (BOE/d)	276,168	270,173	279,784	268,216	287,101

(1) Natural gas liquids include condensate volumes.

Average Royalty Interest Daily Production Volumes - 2015

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids (1)					
Heavy Oil	628	-	304	1,309	911
Light and Medium Oil	1,879	49	940	2,923	3,654
Natural Gas Liquids (2)	105	1	61	173	187
Total Crude Oil and Natural Gas Liquids	2,612	50	1,305	4,405	4,752
Natural Gas (MMcf/d)					
Conventional	10	-	6	14	19
Total (BOE/d)	4,279	50	2,305	6,738	7,919

(1) Cenovus sold the majority of its royalty interest and mineral fee title lands in the third quarter of 2015.
(2) 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:

Per-Unit Results – 2015 (excluding impact of realized gain (loss) on risk management)	Year	Q4	Q3	Q2	Q1
Bitumen - Foster Creek ($/bbl) (1) (2) (3)					
Price	33.65	25.09	33.35	48.25	29.42
Royalties	0.47	0.12	0.20	1.97	(0.25)
Transportation and blending	8.84	8.53	8.50	9.04	9.39
Operating expenses	12.60	11.66	11.27	13.29	14.50
Netback	11.74	4.78	13.38	23.95	5.78
Bitumen - Christina Lake ($/bbl) (1) (2) (3)					
Price	28.45	21.34	27.46	43.36	23.30
Royalties	0.67	0.30	0.83	0.99	0.61
Transportation and blending	4.72	5.40	5.00	4.29	4.17
Operating expenses	8.01	7.80	7.80	8.20	8.24
Netback	15.05	7.84	13.83	29.88	10.28
Total Bitumen - Oil Sands ($/bbl) (1) (2) (3)					
Price	30.88	23.08	30.35	45.61	26.04
Royalties	0.58	0.22	0.52	1.44	0.22
Transportation and blending	6.64	6.85	6.72	6.48	6.50
Operating expenses	10.13	9.59	9.46	10.57	10.99
Netback	13.53	6.42	13.65	27.12	8.33
Heavy Crude Oil - Conventional ($/bbl) (1) (2) (3)					
Price	39.95	32.84	37.09	52.63	35.85
Royalties	2.97	2.24	1.73	5.34	2.34
Transportation and blending	3.36	3.63	3.36	3.09	3.42
Operating expenses	15.92	15.20	15.59	15.45	17.30
Production and mineral taxes	0.04	(0.03)	0.07	0.08	0.02
Netback	17.66	11.80	16.34	28.67	12.77
Total Bitumen and Heavy Crude Oil ($/bbl) (1) (2) (3)					
Price	32.73	24.87	31.63	47.24	28.15
Royalties	1.07	0.59	0.75	2.35	0.68
Transportation and blending	5.97	6.26	6.08	5.69	5.83
Operating expenses	11.31	10.62	10.62	11.70	12.35
Production and mineral taxes	0.01	(0.01)	0.01	0.02	-
Netback	14.37	7.41	14.17	27.48	9.29

(1) Netbacks do not reflect non-cash write-downs of product inventory.
(2) Cost of condensate per barrel of unblended crude oil ($/bbl).
(3) Employee long-term incentive costs were reclassified from operating expenses to general and administrative costs.

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

Bitumen – Foster Creek ($/bbl)	*27.44*	*25.96*	*24.20*	*29.82*	*30.57*
Bitumen – Christina Lake ($/bbl)	*29.50*	*27.39*	*26.42*	*32.90*	*31.60*
Bitumen – Oil Sands ($/bbl)	*28.54*	*26.72*	*25.33*	*31.48*	*31.14*
Heavy Crude Oil – Conventional ($/bbl)	*10.94*	*9.99*	*9.56*	*12.42*	*11.50*
Total Bitumen and Heavy Crude Oil ($/bbl)	*24.94*	*23.64*	*22.34*	*27.06*	*26.91*

Per-Unit Results – 2015 (excluding impact of realized gain (Loss) on risk management)	Year	Q4	Q3	Q2	Q1
Light and Medium Crude Oil ($/bbl) [1]					
Price	50.64	45.35	49.57	61.66	45.81
Royalties	5.66	6.97	7.02	5.67	3.56
Transportation and blending	2.91	2.80	2.88	3.06	2.88
Operating expenses	16.27	17.37	15.92	15.90	16.04
Production and mineral taxes	1.41	0.76	1.60	1.95	1.28
Netback	24.39	17.45	22.16	35.08	22.05
Total Bitumen and Crude Oil (Heavy, Light and Medium) ($/bbl) [1] [2]					
Price	35.41	27.62	34.08	49.55	31.09
Royalties	1.75	1.44	1.60	2.88	1.16
Transportation and blending	5.51	5.79	5.64	5.27	5.34
Operating expenses	12.05	11.52	11.35	12.37	12.97
Production and mineral taxes	0.22	0.10	0.23	0.33	0.22
Netback	15.88	8.77	15.26	28.70	11.40
Natural Gas Liquids ($/bbl)					
Price	30.98	30.70	24.57	39.64	28.51
Royalties	1.74	3.94	1.75	0.87	0.66
Netback	29.24	26.76	22.82	38.77	27.85
Total Bitumen, Crude Oil (Heavy, Light and Medium) and Natural Gas Liquids ($/bbl) [1] [2]					
Price	35.38	27.63	34.03	49.48	31.08
Royalties	1.75	1.46	1.60	2.86	1.16
Transportation and blending	5.48	5.76	5.61	5.24	5.31
Operating expenses	11.98	11.46	11.28	12.29	12.89
Production and mineral taxes	0.22	0.10	0.23	0.33	0.22
Netback	15.95	8.85	15.31	28.76	11.50
Total Natural Gas ($/Mcf) [1]					
Price	2.92	2.78	3.00	2.82	3.05
Royalties	0.07	0.10	0.11	0.03	0.05
Transportation and blending	0.11	0.11	0.10	0.10	0.12
Operating expenses	1.20	1.25	1.16	1.14	1.26
Production and mineral taxes	0.01	0.02	0.01	0.02	0.01
Netback	1.53	1.30	1.62	1.53	1.61
Total ($/BOE) [1] [2]					
Price	30.67	24.78	29.95	40.50	27.73
Royalties	1.40	1.23	1.36	2.13	0.93
Transportation and blending	4.21	4.43	4.35	3.95	4.11
Operating expenses	10.72	10.43	10.18	10.78	11.49
Production and mineral taxes	0.18	0.10	0.19	0.27	0.17
Netback	14.16	8.59	13.87	23.37	11.03

(1) Employee long-term incentive costs were reclassified from operating expenses to general and administrative costs.
(2) Netbacks do not reflect non-cash write-downs of product inventory.

Impact of Realized Gain (Loss) on Risk Management – 2015	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	7.51	11.39	10.07	1.75	6.58
Natural Gas ($/Mcf)	0.37	0.42	0.37	0.39	0.29
Total ($/BOE)	6.11	9.08	8.07	1.92	5.31

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.

2015: Cenovus has 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, 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, Cenovus acquired the Bruderheim rail terminal, a crude-by-rail terminal at Bruderheim, Alberta for $75 million plus adjustments.

2014: Early in the second quarter, Cenovus completed the sale of certain of its Bakken assets for net proceeds of $35 million. Immediately prior to the disposition, the properties were producing an average of 396 barrels per day during the first quarter of 2014. Late in the third quarter, Cenovus also completed the sale of certain Wainwright properties for net proceeds of $234 million. The properties were producing an average of 2,775 barrels per day during the first nine months of 2014.

The following table summarizes Cenovus's net capital investment for 2015 and 2014:

Net Capital Investment

($ millions)	**2015**	2014
Capital Investment		
Oil Sands		
Foster Creek	**403**	796
Christina Lake	**647**	794
Total	**1,050**	1,590
Other Oil Sands	**135**	396
	1,185	1,986
Conventional	**244**	840
Refining and Marketing	**248**	163
Corporate	**37**	62
Capital Investment	**1,714**	3,051
Acquisitions	**87**	18
Divestitures	**(3,344)**	(277)
Net Acquisition and Divestiture Activity	**(3,257)**	(259)
Net Capital Investment (1)	**(1,543)**	2,792

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

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 greenhouse gas ("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".

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. In 2015, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. Cenovus does not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2016. 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 2014 CR report in June 2015, detailing our efforts to accelerate our environmental performance, protect the health and safety of our staff, invest in and engage with the communities where we operate and maintain the highest standards of corporate governance. Our CR report also lists external recognition we received for our commitment to corporate responsibility and our efforts to balance economic, governance, social and environmental performance. Our CR policy and CR report are available on our website at cenovus.com.

EMPLOYEES

The following table summarizes Cenovus's full-time equivalent ("FTE") employees as at December 31, 2015:

	FTE Employees
Upstream	2,001
Downstream	127
Corporate	877
Total	3,005

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
Ralph S. Cunningham [3,4,6] Houston, Texas, United States	2009 Independent	Mr. Cunningham is a director of TETRA Technologies, Inc., a publicly traded energy services and chemicals company, and served as Chairman from December 2006 to May 2015. Mr. Cunningham also served as Chairman of Enterprise Products Holdings, LLC, the successor general partner of Enterprise Products Partners L.P., a publicly traded midstream energy limited partnership, from November 2010 to February 2013, and as a director from February 2013 to April 2014; and as a director of Agrium Inc., a publicly traded agricultural chemicals company from December 1996 to April 2013.
Patrick D. Daniel [2,3,4] Calgary, Alberta, Canada	2009 Independent	Mr. Daniel is a director of Canadian Imperial Bank of Commerce; and 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., 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. He is a member of the Association of Professional Engineers and Geoscientists of Alberta.
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 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. He also served as Chairman and Chief Executive Officer of Sherritt from January 2009 to December 2011 and Chairman of Sherritt 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. Mr. Ferguson is a Fellow of the Chartered Professional Accountants of Alberta and a member of the Chartered Professional Accountants of Canada. Mr. Ferguson has served as a director of The Toronto-Dominion Bank since April 2015.
Michael A. Grandin [4,8] Calgary, Alberta, Canada	2009 (Chair) Independent	Mr. Grandin is the Chair of Cenovus's Board. He is also a director of BNS Split Corp. II, a publicly traded investment company; and HSBC Bank Canada.

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years
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; a lead director 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 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.
Valerie A.A. Nielsen [2,4,5] Calgary, Alberta, 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 [4,5,6] Dallas, Texas, United States	2009 Independent	Mr. Rampacek is a director of Flowserve Corporation, a publicly traded manufacturer of industrial equipment; and 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 previously 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 [2,3,4] 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 [4,5,6] 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 private North American oil and gas company; Chairman of Inventys Thermal Technologies Inc., a private carbon capture technology company; a director of Iskander Energy Corp., a private international oil and gas company; and Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves. Mr. Thomson served as Chief Executive Officer of Iskander Energy Corp. from November 2011 to August 2014. Mr. Thomson is a member of the Association of Professional Engineers and Geoscientists of Alberta.

(1) Each of the directors first became members of Cenovus's Board pursuant to the Arrangement, with the exception of Mr. Leer who was elected as a director of Cenovus's Board at the April 29, 2015 Annual and Special Meeting of Shareholders. 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.

EXECUTIVE OFFICERS

The following individuals served as executive officers of Cenovus as at December 31, 2015.

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.
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.
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, 2015, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,055,623 common shares of Cenovus ("Common Shares") or approximately 0.127 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 (collectively, an "Order") and that was issued while that person 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 of the Corporation being the subject of such an Order 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 penalty 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*.

On June 25, 2001, USG and 10 of its subsidiaries filed for reorganization under Chapter 11 of the Bankruptcy Code (U.S.). On June 20, 2005, Mr. Leer joined the board of directors of USG. On February 17, 2006, USG announced a joint plan of reorganization pursuant to which all creditors would be paid in full. On June 20, 2006, the plan received court approval and USG and those subsidiaries emerged from bankruptcy.

Mr. Rampacek was the Chairman and President & Chief Executive Officer of Probex Corporation ("Probex") in 2003 when it filed a petition seeking relief under Chapter 7 of the Bankruptcy Code (U.S.). In 2005, as a result of the bankruptcy, two complaints seeking recovery of certain alleged losses were filed against former Probex officers and directors, including Mr. Rampacek. These complaints were defended by American International Group, Inc. ("AIG") in accordance with the Probex director and officer insurance policy and settlement was reached and paid by AIG, with bankruptcy court approval, in 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt, of which Mr. Rampacek was a party. A settlement of $2,000 was reached, with bankruptcy court approval, in 2006.

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* ("NI 52-110"). 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 Inc., 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 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; a lead director 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 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 and President from July 1992 to April 2006. He is a member of the Board of Trustees of Washington University in St. Louis and he is a former director of the Business Roundtable and the National Association of Manufacturers.

Valerie A.A. Nielsen

Ms. Nielsen holds a Bachelor of Science (Hon.) (Dalhousie University). She is a professional geophysicist who has held management positions and provided consulting services to the oil and gas industry for over 30 years. She has also completed several finance and accounting courses at the university level. Ms. Nielsen was a member and past chair of an advisory group on the General Agreement on Tariffs and Trade (GATT), the North America Free Trade Agreement (NAFTA) and international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. She is a past director and served on the audit committee of Wajax Corporation, a publicly traded company engaged in the sale and after-sales parts and service support of mobile equipment, diesel engines and industrial components. She is a past director of the Bank of Canada and of the Canada Olympic Committee.

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.

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. 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, 2015 and 2014:

($ thousands)	**2015**	2014
Audit Fees (1)	**2,692**	2,597
Audit-Related Fees (2)	**482**	202
Tax Fees (3)	**99**	110
All Other Fees (4)	**-**	6
Total	**3,273**	2,915

(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 debt shelf 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 consist of subscriptions to auditor-provided and supported tools.

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 the "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, 2015, 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. The Corporation's Board is restricted from issuing First Preferred Shares or Second Preferred Shares if by doing so the aggregate number of First Preferred and Second Preferred Shares that would then be issued and outstanding would exceed 20 percent of the aggregate number of Common Shares then issued and outstanding.

SHAREHOLDER RIGHTS PLAN

Cenovus has a 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 (the "DRIP"), 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 average market price or purchased on the market.

On July 30, 2015 the temporary discount on Common Shares issued to participants under the DRIP introduced on February 12, 2015, was discontinued. The discount allowed shareholders to reinvest their dividends in Common Shares at a three percent discount to the average market price (as defined in the DRIP).

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 and its access to sources of liquidity and capital. 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	Baa2	BBB (high)
Commercial Paper Short-Term Rating	A-2	P-2	R-2 (high)
Outlook/Trend	Stable	Rating Under Review for downgrade	Negative

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. S&P's short-term issue credit ratings scale ranges from A-1 to D, which represents the range from highest to lowest quality. A rating of A-2 is the second highest of six categories and indicates that the obligor is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitment on the obligation is satisfactory. 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 Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. 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. Moody's short-term credit ratings are on a scale that ranges from P-1 (highest quality) to NP (lowest quality). A rating of P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations. A designation of Rating Under Review indicates that the rating is under review for a change in the near term, which overrides the outlook designation. A review may end with a rating being upgraded, downgraded, or confirmed without a change to the rating. Ratings are placed on review when a rating action may be warranted in the near-term but further information or analysis is needed to reach a decision on the need for a rating change or the magnitude of the potential change.

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. DBRS's short-term credit ratings are on a scale ranging from R-1 (high) to D, which represents the range from highest to lowest quality. A rating of R-2 (high) is the fourth highest of 10 categories and indicates that the short-term debt is in the upper end of adequate credit quality. The capacity for the payment of short-term financial obligations as they fall due is acceptable. Cenovus may be vulnerable to future events. 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 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 third quarter of 2015, Cenovus reduced the quarterly dividend by 40 percent from $0.2662 to $0.16 per common share. The Board has approved a first quarter dividend of $0.05 per share payable on March 31, 2016 to holders of Common Shares of record as of March 15, 2016. 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
2015	0.8524	0.16	0.16	0.2662	0.2662
2014	1.0648	0.2662	0.2662	0.2662	0.2662
2013	0.968	0.242	0.242	0.242	0.242

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange ("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 2015:

	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	24.95	21.87	24.09	86,649	20.89	17.37	18.89	49,901
February	26.42	21.56	21.57	99,513	21.12	17.24	17.29	56,777
March	22.48	20.45	21.34	101,794	17.93	16.29	16.88	47,505
April	24.28	21.32	22.69	95,632	19.72	16.89	18.82	42,962
May	23.25	20.23	20.52	77,995	19.28	16.20	16.49	38,034
June	21.69	19.53	19.98	84,576	17.76	15.69	16.01	49,516
July	20.07	16.98	19.06	86,880	15.97	13.04	14.58	50,471
August	19.28	15.75	19.07	84,803	14.67	11.85	14.47	51,293
September	20.91	17.00	20.24	135,093	15.80	12.76	15.16	74,684
October	22.35	18.75	19.48	90,746	17.23	14.17	14.91	65,312
November	21.81	19.10	19.81	65,882	16.68	14.32	14.80	39,867
December	20.56	16.85	17.50	76,299	15.38	12.10	12.62	38,971

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 flow, 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 ("COMS"). 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 substantially 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; government regulation; political stability; the ability to transport crude to markets; the availability of alternate fuel sources; and weather conditions. Cenovus's natural gas price realizations 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. The Corporation's refined product prices are impacted by a number of factors including, but not limited to: global supply and demand for refined products; market competitiveness; weather; and industry planned and unplanned refinery maintenance. 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 also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Corporation's light/medium oil, heavy oil (in particular the light/heavy differential) and bitumen and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond Cenovus's control.

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.

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: 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 downside price risk 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 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, 2015, 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 November 30, 2017 and a $3.0 billion tranche maturing on November 30, 2019. The entire amount of the committed credit facility was available at December 31, 2015, 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 also 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 required. If external sources of capital become limited or unavailable, and/or if repayment is required before maturity, the Corporation's ability to make capital investments, continue its business plan, meet all of its financial obligations as they come due and maintain existing properties and facilities may be impaired.

Credit Ratings

The credit rating agencies regularly evaluate the Corporation, and their ratings are based on a number of factors not entirely within the Corporation's control, including conditions affecting the oil and gas industry generally, and the wider 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.

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 as well as its Consolidated Financial Statements are denominated in Canadian dollars. Cenovus has chosen to borrow U.S. dollar long-term debt. 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. In addition, 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 flow.

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 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.

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; and acts of vandalism and terrorism. 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, marine or rail transport, could adversely affect the Corporation's crude oil and natural gas sales, projected production growth, refining operations and its cash flow. 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 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. 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 incident 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 were introduced in 2015 requiring 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; blowouts; equipment failures and other accidents; sour gas releases; uncontrollable flows of crude oil, natural gas or well fluids; 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; slowdowns due to equipment failure or transportation disruptions; weather; fires, and 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 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 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 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.

If the Corporation fails to acquire, develop or find additional crude oil and natural gas reserves, its reserves and production will decline materially from their current levels and therefore Cenovus's business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

Project Execution

There are risks associated with the execution and operation of the Corporation's upstream and refining 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 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 our 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 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 coincide with and 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 licenses 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 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 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 flow. 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.

Third-Party Claims

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. The outcome of such litigation may materially impact Cenovus's financial condition or results of operations. 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.

Leadership and Talent

Cenovus's success is dependent upon its Management, its leadership capabilities and the quality and competency of its talent. Failure to retain critical talent or to attract and retain new talent with the necessary leadership traits, skills and competencies could have a material adverse effect on the Corporation's results of operations, pace of growth and financial condition.

Information Systems

The Corporation depends on a variety of information systems to operate effectively. A failure or act of sabotage of certain business critical information systems could result in operational difficulties or mishap, damage or loss of data, productivity losses or result in unauthorized knowledge and use of information.

ENVIRONMENTAL & REGULATORY RISKS

Cenovus's industry and its operations are subject to regulation and intervention under federal, provincial, 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 greenhouse gas 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 our financial condition, results of operations and cash flows.

Regulatory Approvals

Cenovus's operations require the Corporation to obtain approvals from various regulatory authorities and there are no guarantees that it will be able to obtain all necessary licenses, 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; regulatory oversight of projects by third parties; 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.

Royalty Regimes

The Corporation's cash flow 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. The royalty rate that Cenovus is charged on its oil sands production is determined based on the Canadian dollar equivalent price of West Texas Intermediate ("WTI"), and therefore increases in WTI or decreases in the CDN$/US$ exchange rate could significantly increase its royalties, which may have a negative impact on the Corporation's business, financial conditions, results of operations and cash flow. There is also a mineral tax in each province levied on hydrocarbon production from lands to which the Crown does not own the mineral rights. The potential for changes in the royalty and mineral tax regimes applicable in the provinces Cenovus operates creates uncertainty relating to the ability to accurately estimate future Crown burdens.

Alberta Royalty Review

The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 (the "Review"). The Review recommends new rules coming into effect in 2017, but also recommends grandfathering, under the current rules, all wells drilled before 2017 for a ten year period and recommends no change to the oil sands royalty structure. The Review recommended modernization of Alberta's conventional oil and gas royalty regime, but did not provide detail. The Government of Alberta has accepted the recommendations set out in the Review and is expected to adopt those recommendations in spring 2016. It is not anticipated that the new rules will materially impact Cenovus's financial condition; however, the specific nature in which the new rules will be applied has not yet been determined and may alter this view.

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 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.

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 requirement 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 fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations can require significant expenditures, including costs and damages arising from releases or contaminated properties or spills. 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 costs.

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

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("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

We are subject to the Specified Gas Emitters Regulation (Alberta) (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes per year or more of GHG, which was recently amended. Previously, an owner of such a facility was required to reduce the emissions intensity of that facility by a minimum of 12 percent. The amendments have increased the minimum emission intensity reduction requirement for facility owners to 15 percent in 2016 and 20 percent starting in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The amendments have increased the price for such credits from $15/tonne to $20/tonne for 2016 and $30/tonne beginning in 2017.

In November, 2015, the Alberta government announced its climate leadership plan (the "CLP") and released to the public the climate leadership report to the Minister of Environment and Parks (the "Report") that it commissioned from the Climate Change Advisory Plan and on which the CLP is based. The CLP includes four strategies that the government will implement to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030; (ii) implementing an Alberta economy-wide price on GHG emissions of $30 per tonne; (iii) reducing 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 (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Uncertainties exist with respect to the implementation of the CLP and the effects that the CLP, including the overall emissions limit, may have on the industry.

Adverse impacts to Cenovus's business as a result of comprehensive GHG legislation or regulation, including legislation to implement the CLP and the amendments to the SGER, to be enacted and 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.

The Paris Agreement

In December 2015, Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius." The countries which agreed to the Paris Agreement committed to meeting every five years to review their individual progress on GHG emissions reductions and to consider amendments to non-binding individual country targets. Canada is required to report and monitor its GHG emissions, though the implementation of such reporting and monitoring has yet to be determined. The Paris Agreement also contemplates that by 2020 the parties thereto will develop a new market-based mechanism related to carbon trading, which is expected to be based largely on lessons learned from the Kyoto Protocol. The government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016.

The Corporation is unable to predict the impact of the Paris Agreement on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on Cenovus's financial condition, results of operations and cash flow.

Low Carbon Fuel Standards

Existing and proposed environmental legislation in certain U.S. states, Canadian provinces and in 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 refiners to blend renewable fuels such as ethanol and advanced biofuels with their gasoline. 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 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 flow 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, licenses, 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 has approved the Lower Athabasca Regional Plan ("LARP"), which was issued under the ALSA. The LARP 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. 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 approved 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 commenced development of the North Saskatchewan Regional Plan ("NSRP"). 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 which are to come into effect 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 limit the Corporation's pace and amount of development and, in some cases, may result in an inability to further develop or continue to develop or operate in affected areas.

Federal Air Quality Management System

In June 2014, under the Federal Air Quality Management System, Environment Canada announced draft Multi-sector Air Pollutants Regulations ("MAPR"). The draft MAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Under the draft MAPR, nitrogen oxide BLIERs from the Corporation's non-utility boilers, heaters and reciprocating engines will be regulated in accordance with specified performance standards. Due to the recent change in government, it is unclear when these regulations will come into force. Cenovus does not anticipate a material impact to existing or future operations as a result of the MAPR.

Water Licenses

Cenovus currently utilizes fresh water in certain operations, which is obtained under licenses 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 licenses. If a change under these licenses 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 licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that 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 licenses for additional water withdrawal, and there can be no assurance that these licenses 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 licenses.

Alberta Wetlands Policy

In September 2013, the Government of Alberta approved a new wetlands policy to be fully implemented by June 2015 in southern Alberta ("White Area") and June 2016 for the boreal region ("Green Area"). This new policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, where the Corporation's ten year wetlands mitigation and monitoring plans were approved under the previously existing wetlands policy.

New project developments and future phase expansions will likely be affected by this policy. Cenovus's oil sands leases are in areas where wetlands cover over 50% of the landscape. 'Avoidance' may not be an option for new project developments and phase expansions. Additional details of the wetlands assessment and compensation requirements are still to be determined within the policy. Based on written statements in the Alberta Wetland Mitigation Directive, 2015, Cenovus does not anticipate a material impact; however with the change in the provincial government 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 and Influence on Regulatory Regime

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 Management's Discussion and Analysis, available at sedar.com, sec.gov and cenovus.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2015, 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, 2015, there were no penalties or sanctions imposed against Cenovus by a court relating to provincial and territorial 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 provincial and territorial 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 10 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 or any proposed transaction that has materially affected or is reasonably expected to materially affect Cenovus.

MATERIAL CONTRACTS

During the year ended December 31, 2015, 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 10, 2016 in respect of Cenovus's Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2015 and December 31, 2014 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2015, 2014, and 2013 and Cenovus's internal control over financial reporting as at December 31, 2015. 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 Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd. as independent qualified reserves evaluators. The principals of each of GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd., 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, 2015. Additional disclosure, 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 proxy 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, 2015, 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, 2015 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		Natural Gas	
bbl	barrel	Bcf	billion cubic feet
bbls/d	barrels per day	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBtu	million British thermal units
BOE	barrel of oil equivalent	CBM	Coal Bed Methane
BOE/d	barrels of oil equivalent per day		
WTI	West Texas Intermediate		

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.

TM denotes a trademark of Cenovus Energy Inc.

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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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") and 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 sets forth the estimated 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, 2015, 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, 2015	Canada	$20,280
GLJ Petroleum Consultants Ltd.	December 31, 2015	Canada	$1,286
			$21,566

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

McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

/s/ Keith M. Braaten

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 9, 2016

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management and directors 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 from 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; and

(c) reviewed the reserves data with management and each of the independent qualified reserves evaluators.

The Board of Directors of the Corporation has 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 10, 2016

APPENDIX C

AUDIT COMMITTEE MANDATE

I. PURPOSE

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.

II. COMPOSITION AND MEETINGS

Composition

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.

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.

Vacancies

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

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.

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.

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 President & 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.

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.

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.

Attendance at Meetings

The President & Chief Executive Officer, the Executive Vice-President & 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.

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.

III. RESPONSIBILITIES

Review Procedures

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.

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.

Annual Financial Statements

1. 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:

    (a) 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.
    (b) Management's Discussion and Analysis.
    (c) The use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.
    (d) The external auditors' audit examination of the financial statements and their report thereon.
    (e) Any significant changes required in the external auditors' audit plan.
    (f) 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.
    (g) Other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Review and formally recommend approval to the Board of the Corporation's:

    (a) 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.
    (b) Management's Discussion and Analysis.
    (c) Annual Information Form as to financial information.
    (d) 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.

Quarterly Financial Statements

3. 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:

    (a) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.
    (b) Any significant changes to the Corporation's accounting principles.

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

Other Financial Filings and Public Documents

4. 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 news 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.

Internal Control Environment

5. 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.
6. 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.
7. 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.
8. Review with the President & Chief Executive Officer, the Executive Vice-President & 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.
9. Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

Risk Oversight

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

Other Review Items

11. 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.
12. Review all related party transactions between the Corporation and any executive officers or directors, including affiliations of any executive officers or directors.
13. 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.
14. 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.
15. 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.
16. Ensure that the Corporation's presentation of hydrocarbon reserves has been reviewed with the Reserves Committee of the Board.
17. Review management's processes in place to prevent and detect fraud.
18. Review:

    (a) 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

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

19. Meet on a periodic basis separately with management.

External Auditors

20. 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.

21. 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.

22. Review and discuss a report from the external auditors at least quarterly regarding:

    (a) All critical accounting policies and practices to be used;
    (b) 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
    (c) Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

23. Obtain and review a report from the external auditors at least annually regarding:

    (a) The external auditors' internal quality-control procedures.
    (b) 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.
    (c) To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

24. 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.

25. Review and evaluate annually:

    (a) 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.
    (b) The terms of engagement of the external auditors together with their proposed fees.
    (c) External audit plans and results.
    (d) Any other related audit engagement matters.
    (e) 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.
    (f) Review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for Cenovus.
    (g) Review any reports issued by CPAB regarding the audit of Cenovus.

26. 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.

27. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 22 through 25, 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.

28. 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.

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

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

31. Consider and review with the external auditors, management and the head of internal audit:

    (a) Significant findings during the year and management's responses and follow-up thereto.
    (b) 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.
    (c) Any significant disagreements between the external auditors or internal auditors and management.
    (d) Any changes required in the planned scope of their audit plan.
    (e) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.
    (f) The internal audit department mandate.
    (g) Internal audit's compliance with the Institute of Internal Auditors' standards.

Internal Audit Group and Independence

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

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

34. Confirm and assure, annually, the independence of the internal audit group and the external auditors.

Approval of Audit and Non-Audit Services

35. 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).

36. 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.

37. If the pre-approvals contemplated in paragraphs 34 and 35 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.

38. 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 34 through 36. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

39. Establish policies and procedures for the pre-approvals described in paragraphs 34 and 35 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.

Other Matters

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

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

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

43. 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.

44. 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.

45. 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.

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

47. 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.

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

49. Consider any other matters referred to it by the Board of Directors.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2015

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 10, 2016, should be read in conjunction with our December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 10, 2016, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 10, 2016. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures

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

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2015, we had a market capitalization of approximately $15 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in 2015 was approximately 207,000 barrels per day and our average natural gas production was 441 MMcf per day. Our refineries processed an average of 419,000 gross barrels per day of crude oil feedstock into an average of 444,000 gross barrels per day of refined products.

Our Key Message for 2015

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

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

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

Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving stronger global prices for our products. It is based on our disciplined execution, focused innovation and our financial strength. The manufacturing approach we use to produce crude oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns.

Our integrated approach positions us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for long-term growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will position us to achieve the best pricing for our oil.

We have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities.

We are positioned to increase our annual net crude oil production, including our conventional crude oil operations, by fully developing our production projects and those that currently have regulatory approval.

Disciplined Manufacturing

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, positioning us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

Financial Strength

Maintaining a strong balance sheet is necessary to execute our strategy. We anticipate our total annual capital investment for 2016 to be between $1.2 billion and $1.3 billion. This is 27 percent lower than in 2015, reflecting moderate spending in response to the sustained low commodity price environment. At December 31, 2015, we had $4.1 billion of cash on hand, $4.0 billion of undrawn capacity on our committed credit facility, and no debt maturing until the fourth quarter of 2019. To help ensure our continued financial flexibility, we will pursue further cost reductions, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In 2015, we paid a dividend of $0.8524 per share compared with $1.0648 per share in 2014 (2013 – $0.968 per share). We reduced our dividend by 40 percent in the third quarter of 2015, from $0.2662 per share to $0.16 per share, as part of our strategy to maintain our long-term financial resilience. Our dividend was further reduced to $0.05 per share in the first quarter of 2016. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

Focused Innovation

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing technologies with a focus on increasing recoveries from our reservoirs, and improving cycle times, margins and environmental performance. We have a track record of developing innovative solutions that unlock challenging crude oil resources, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

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

	2015		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	65,345	130,690
Christina Lake	50	74,975	149,950
Narrows Lake	50	-	-
Emerging Projects			
Telephone Lake	100	-	-
Grand Rapids	100	-	-

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

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

Conventional

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

	2015	
($ millions)	Crude Oil [1]	Natural Gas
Operating Cash Flow	683	297
Capital Investment	231	13

Operating Cash Flow Net of Related Capital Investment	**452**	**284**

(1) *Includes NGLs.*

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

Refining and Marketing

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

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

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

($ millions)	2015
Operating Cash Flow	385
Capital Investment	248
Operating Cash Flow Net of Related Capital Investment	**137**

2015 HIGHLIGHTS

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

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

In 2015, we also:

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

OPERATING RESULTS

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

Crude Oil Production Volumes

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

(1) NGLs include condensate volumes.

Foster Creek production increased in 2015 due to the ramp-up of production from phase F and production from additional wells, partially offset by the impact of a forest fire in the second quarter, which decreased full-year production by approximately 2,600 barrels per day. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

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

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

Natural Gas Production Volumes

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

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

Oil and Gas Reserves

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

Operating Netbacks

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

(1) Includes NGLs.
(2) The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was $21.09 per barrel (2014 – $30.49 per barrel; 2013 – $28.33 per barrel).
(3) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.
(4) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.

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

In 2015, our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the decline in the AECO benchmark price.

Refining

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

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

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

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

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

(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.
(2) The average Canadian dollar WCS benchmark price for 2015 was $45.12 per barrel (2014 – $81.33 per barrel; 2013 – $74.94 per barrel); fourth quarter average WCS benchmark price was $36.97 per barrel (2014 – $66.87 per barrel).
(3) The average Canadian dollar condensate benchmark price for 2015 was $60.56 per barrel (2014 – $102.71 per barrel; 2013 – $104.73 per barrel); fourth quarter average condensate benchmark price was $55.63 per barrel (2014 – $80.10 per barrel).

Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices continued to be impacted by a global imbalance of supply and demand which began in the second half of 2014. This imbalance, created by weak global demand for oil and strong growth in North American crude oil supply, was further amplified by the sustained decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Despite significantly lower crude oil prices and increased global demand in 2015, the imbalance has only slightly improved. Economic uncertainty in China, resilient U.S. production, continued strong production from Saudi Arabia and Iraq, as well as concerns regarding the return of Iranian production have contributed to sustained low crude oil prices.

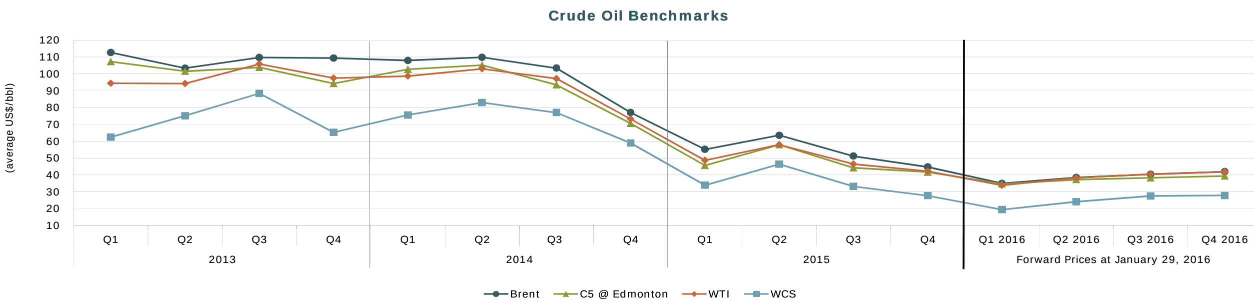
The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed compared with 2014. WTI benchmark prices strengthened relative to Brent as a result of high global crude oil inventory levels and continued strong demand in the U.S., leaving transportation costs as the primary driver of the Brent-WTI differential.

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

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

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



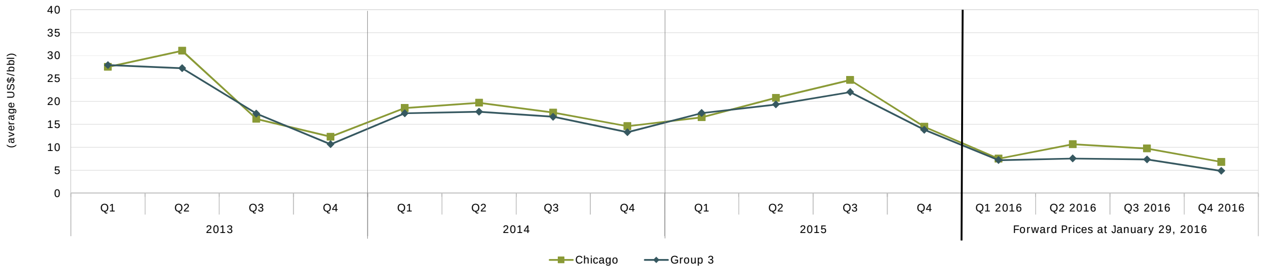
Refining Benchmarks

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

Average Chicago 3-2-1 crack spreads increased in 2015 compared with 2014 driven by stronger product demand. Average Group 3 crack spreads increased as a major unplanned refinery outage in August 2015 caused product inventory drawdowns during the driving season.

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

Refining 3-2-1 Crack Spread Benchmarks



Natural Gas Benchmarks

Average natural gas prices decreased in 2015 primarily due to increased supply from the U.S. and Canada.

Foreign Exchange Benchmarks

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

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

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

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

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

Revenues

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

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

Revenues from our Refining and Marketing segment decreased 30 percent from 2014. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2015 decreased 36 percent from 2014, primarily due to a decline in sales prices, partially offset by an increase in purchased crude oil volumes.

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

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

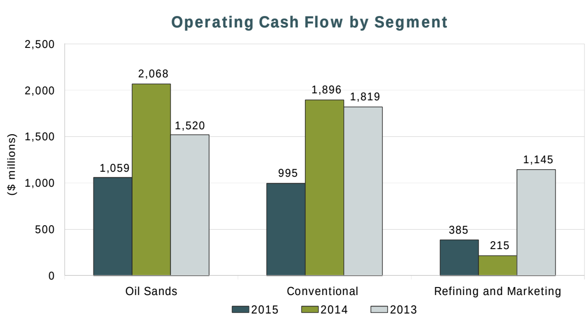
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

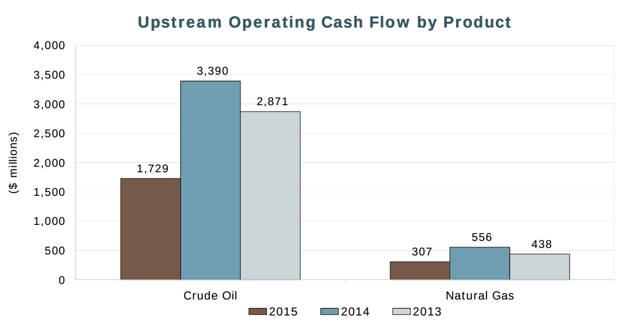
Operating Cash Flow

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

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

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





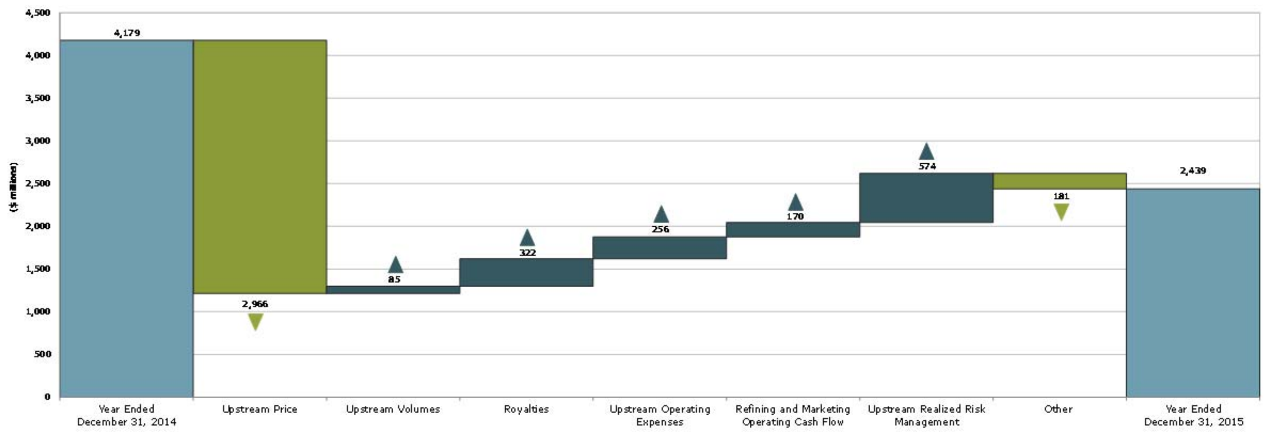
Operating Cash Flow declined 42 percent in 2015 primarily due to:

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

These declines to Operating Cash Flow were partially offset by:

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

Operating Cash Flow Variance



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

Cash Flow

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

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

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

Operating Earnings (Loss)

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

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

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

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

Net Earnings

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

(1) Non-GAAP measure defined in this MD&A.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

In 2015, Net Earnings declined as an after-tax gain of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business, and a deferred tax recovery related to non-operating items compared with an expense in 2014, were more than offset by:

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

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

Net Capital Investment

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

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

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

In 2015, Oil Sands capital investment focused on sustaining capital related to existing production, the phase G expansion at Foster Creek, and Christina Lake optimization project and phase F expansion. We drilled 164 gross stratigraphic test wells at Foster Creek and Christina Lake to determine pad placement for sustaining wells and near-term expansion phases.

Conventional capital investment focused on maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn and drilling activity in the second half of the year at our tight oil projects in southeast Alberta.

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

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

Acquisitions and Divestitures

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

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

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

We had no material acquisitions in 2014 or 2013.

Capital Investment Decisions

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

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

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

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

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

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

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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

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

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

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

Revenues by Reportable Segment

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

OIL SANDS

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

Significant developments in our Oil Sands segment in 2015 compared with 2014 include:

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

Oil Sands – Crude Oil

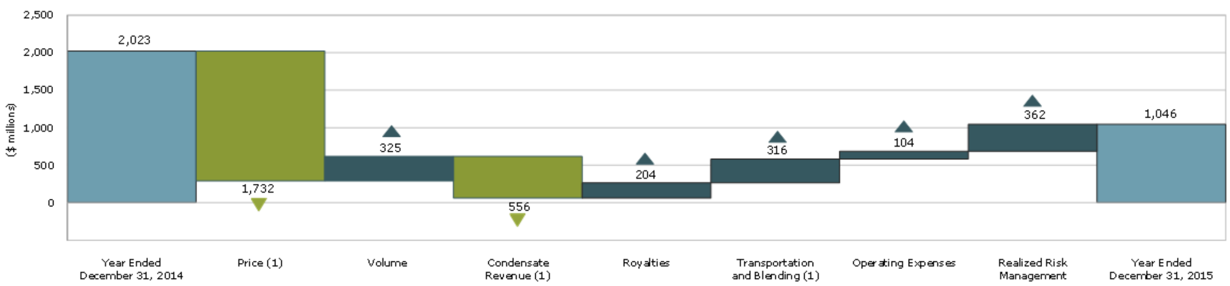
Financial and Per-unit Results

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

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

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

Operating Cash Flow Variance



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

Revenues

Pricing

In 2015, our average crude oil sales price was $30.88 per barrel, a 53 percent decrease from 2014 as the prices we received were adversely impacted by the worldwide low commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market which generally secure a higher sales price. The WCS-CDB differential narrowed by 40 percent to a discount of US$2.37 per barrel (2014 – a discount of US$3.94 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In 2015, 86 percent of our Christina Lake production was sold as CDB (2014 – 88 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

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

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

Production from Christina Lake increased in 2015 due to production from additional wells, phase E reaching nameplate production capacity in the second quarter of 2014, and improved performance of our facilities.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

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

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

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

Effective Royalty Rates

(percent)	**2015**	2014	2013
Foster Creek	**1.9**	8.8	5.8
Christina Lake	**2.8**	7.5	6.8

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

Expenses

Transportation and Blending

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

Transportation costs increased primarily due to higher pipeline tariffs and higher tariffs from additional sales to the U.S. market, which generally secure higher sales prices. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

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

Operating

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

Per-unit Operating Expenses

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

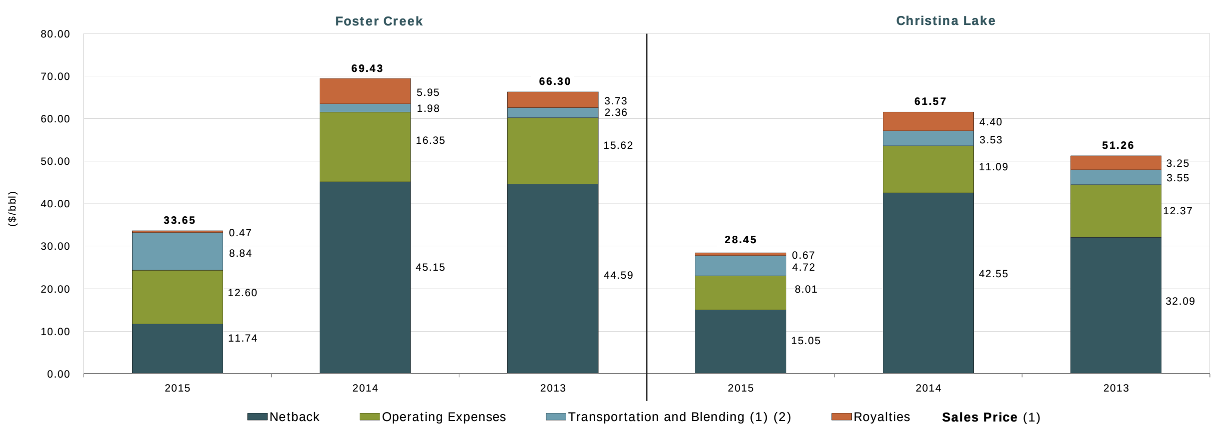
(1) *For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.*

At Foster Creek, fuel costs decreased due to lower natural gas prices and a decline in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:
- Higher production volumes;
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Lower electricity costs.

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

At Christina Lake, fuel costs decreased due to lower natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:
- Increased production;
- Lower workover costs related to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities and no turnaround costs in 2015.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in 2015 was $27.44 per barrel (2014 – $42.01 per barrel; 2013 – $42.41 per barrel) for Foster Creek, and $29.50 per barrel (2014 – $45.45 per barrel; 2013 – $45.25 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

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

Risk Management

Risk management activities in 2015 resulted in realized gains of $400 million (2014 – $38 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2015, net of internal usage, was 19 MMcf per day (2014 – 22 MMcf per day). Operating Cash Flow was $10 million in 2015 (2014 – $46 million) primarily due to the decline in natural gas sales prices.

Oil Sands – Capital Investment

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

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

Existing Projects

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

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

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

Emerging Projects

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

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

Drilling Activity (1)

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

(1) *In addition to the drilling activity included within the table, we drilled eight gross service wells in 2015 (2014 – three gross service wells; 2013 – 27 gross service wells).*
(2) *Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In 2015, we drilled seven wells (2014 – 14 wells; 2013 – 24 wells) and commissioned our second SkyStrat™ drilling rig.*
(3) *SAGD well pairs are counted as a single producing well.*

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

Future Capital Investment

Due to our expectation that low commodity prices will persist for an extended period, we have adopted a more moderate and staged approach to future oil sands expansions. Expanding existing projects and developing emerging projects will depend upon commodity prices, achieving further cost reductions as well as additional fiscal and regulatory certainty.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2016 is forecast to be between $325 million and $350 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the third quarter of 2016. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between $350 million and $375 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016. Construction work on phase G was deferred earlier in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

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

Emerging Projects

Capital investment for our new resource plays is forecast to be between $45 million and $55 million in 2016. As of February 2016, further activity in respect of the SAGD pilot at Grand Rapids has been deferred in response to the current low commodity price environment.

DD&A and Exploration Expense

DD&A

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

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

Exploration Expense

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

CONVENTIONAL

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

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

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

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

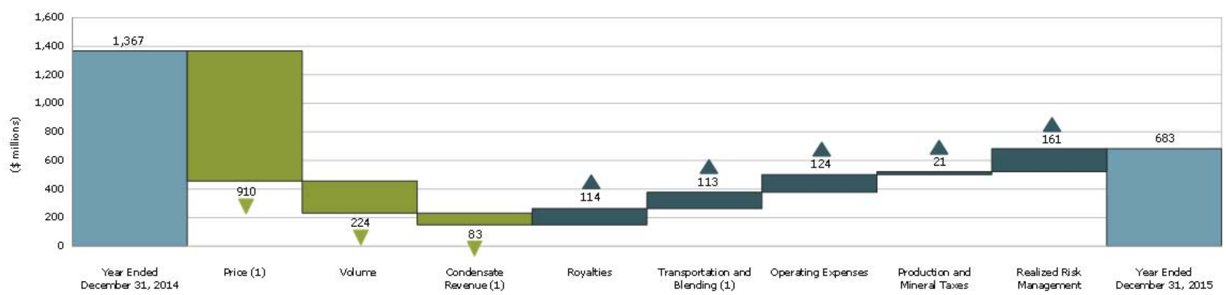
Conventional – Crude Oil

Financial and Per-unit Results

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

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

Operating Cash Flow Variance



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

Revenues

Pricing

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

Production Volumes

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

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

Condensate

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

Royalties

Royalties decreased $114 million primarily due to lower realized sales prices, partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business. For 2015, the effective crude oil royalty rate for our Conventional properties was 9.9 percent (2014 – 10.1 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. The Pelican Lake royalty calculation was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

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

Expenses

Transportation and Blending

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

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

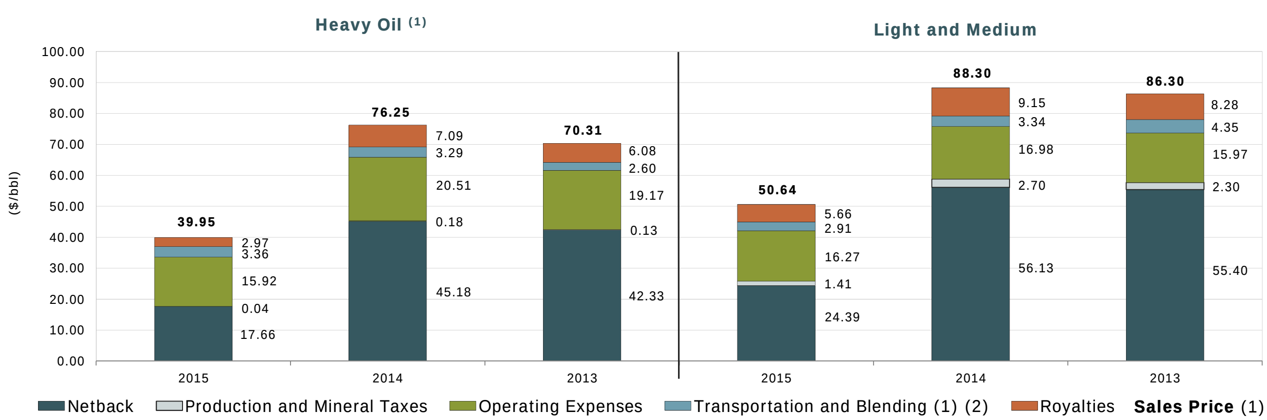
Operating

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

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

These decreases were partially offset by lower production.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $10.94 per barrel (2014 – $15.71 per barrel; 2013 – $14.60 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

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

Risk Management

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

Conventional – Natural Gas

Financial Results

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

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

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

Revenues

Pricing

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

Production

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

Royalties

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

Expenses

Transportation

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

Operating

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

Risk Management

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

Conventional – Capital Investment

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

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

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

Drilling Activity

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

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

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

Future Capital Investment

Consistent with our expectation that commodity prices will continue to be low for a prolonged period of time, we are taking a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

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

DD&A, Goodwill Impairment and Exploration Expense

DD&A

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

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

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

Goodwill Impairment

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

Exploration Expense

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

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

REFINING AND MARKETING

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

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

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

Refinery Operations [1]

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

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

On a 100-percent basis, our refineries have total capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to refine heavy crude oil demonstrates our ability to economically integrate our heavy crude oil production. The discount of WCS relative to WTI benefits our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

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

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. The volume of heavy crude oil processed in 2015 increased slightly from 2014.

Financial Results

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

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

Gross Margin

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

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

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

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

The weakening of the Canadian dollar relative to the U.S. dollar in 2015, compared with 2014, had a positive impact of approximately $143 million on our refining gross margin.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In 2015, the cost of our RINs was $200 million (2014 – $123 million). The increase is consistent with the rise in the ethanol RINs benchmark price.

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

Operating Expense

Primary drivers of operating expenses in 2015 were maintenance, labour, utilities and supplies. Reported operating expenses increased compared with 2014 primarily due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by a decline in utility costs resulting from lower natural gas prices.

Refining and Marketing – Capital Investment

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

Capital expenditures in 2015 focused on the debottlenecking project at Wood River, capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives. We received permit approval in the first quarter of 2015 for the Wood River debottlenecking project and start-up is anticipated in the third quarter of 2016.

In 2016, we expect to invest between $240 million and $290 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from 3 to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $35 million in 2015, primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the long-term power purchase contract and interest rate swaps. In 2015, our risk management activities resulted in $195 million of unrealized losses (2014 – $596 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

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

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

Expenses

General and Administrative

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

Finance Costs

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

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

Foreign Exchange

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

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

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2015 was $78 million (2014 – $83 million).

Income Tax

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

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

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

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

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

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

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

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

QUARTERLY RESULTS

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

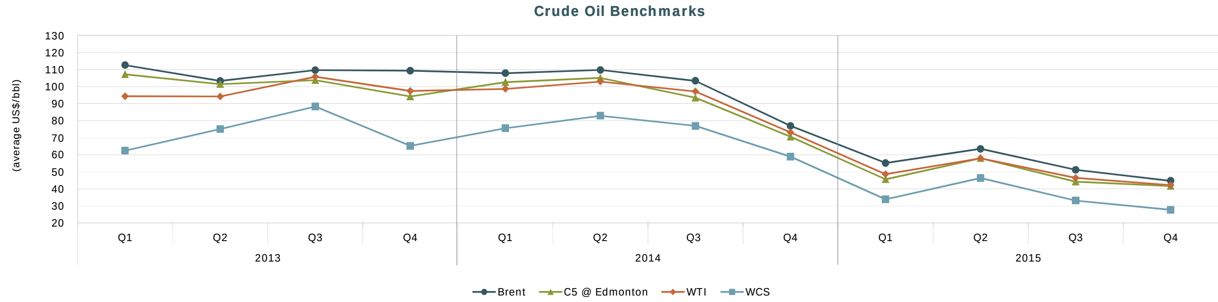
($ millions, except per share amounts or where otherwise indicated)	2015				2014				2013
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production Volumes									
Crude Oil (bbls/d)	199,556	210,422	199,954	218,020	216,177	199,089	201,688	196,854	188,743
Natural Gas (MMcf/d)	424	430	450	462	479	489	507	476	514
Refinery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

(1) Non-GAAP measure defined in this MD&A.

(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

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

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



Fourth Quarter 2015 Results as Compared with the Fourth Quarter 2014

Production Volumes

Total crude oil production declined eight percent primarily due to expected natural declines, the sale of our royalty interest and mineral fee title lands business, and lower production at Foster Creek. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

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

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

Refinery Operations

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

Revenue

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

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

The decreases to revenues were partially offset by:

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

Operating Cash Flow

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

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

Cash Flow

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

Operating Earnings (Loss)

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

Net Earnings (Loss)

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

Capital Investment

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

OIL AND GAS RESERVES AND RESOURCES

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

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

Additional developments in 2015 compared with 2014 include:

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

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

Reserves

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

Reconciliation of Proved Reserves

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

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

Reconciliation of Probable Reserves

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

Economic Contingent Resources and Prospective Resources

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

Operating Activities

Cash from operating activities decreased in 2015 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,337 million at December 31, 2015 compared with $772 million at December 31, 2014. Working capital increased due to cash proceeds received on the sale of our royalty interest and mineral fee title lands business in July of 2015 and the common share issuance in the first quarter of 2015.

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

Investing Activities

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

Financing Activities

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

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

Our long-term debt at December 31, 2015 was $6,525 million (December 31, 2014 – $5,458 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $1,067 million increase in long-term debt is due to weakening of the Canadian dollar relative to the U.S. dollar.

As at December 31, 2015, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

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

The following sources of liquidity are available at December 31, 2015:

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

(1) Availability is subject to market conditions.

Committed Credit Facility

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

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

U.S. and Canadian Base Shelf Prospectuses

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

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

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

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

Financial Metrics

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

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

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

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

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

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

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

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

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

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

Share Capital and Stock-Based Compensation Plans

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

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

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

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

Contractual Obligations and Commitments

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

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

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

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

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

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

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

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

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

Legal Proceedings

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

Related Party Transactions

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

RISK MANAGEMENT

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

Risk Governance

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

Risk Assessment

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

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

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

Significant Risk Factors

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

Financial Risk

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

Commodity Prices

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

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

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

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

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

Impact of Financial Risk Management Activities

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

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

Commodity Price Sensitivities – Risk Management Positions

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

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

Risks Associated with Derivative Financial Instruments

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

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

Liquidity

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

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

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

Foreign Exchange Rates

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Operational Risk

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

Market Access and Transportation Restrictions

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

Operational Outages and Major Environmental or Safety Incidents

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

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

Project Execution

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

Cost Management

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

Reserves Replacement

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

Leadership and Talent

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

Regulatory Risk

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

Regulatory Approvals

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

Royalty Regimes

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

Environmental Regulations

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

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

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

Species at Risk Act

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

Climate Change

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

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes per year or more of GHG. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12 percent to 15 percent in 2016 and 20 percent starting in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The SGER amendments have increased the price for such credits from $15/tonne to $20/tonne for 2016 and $30/tonne beginning in 2017.

If comprehensive GHG regulation is enacted in Alberta or any jurisdiction in which we operate, including legislation to implement the CLP, and as a result of the amendments to the SGER, we may incur increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil, natural gas and certain refined products.

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

Water Licenses

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

Alberta's Land-Use Framework

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

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

Critical Judgments in Applying Accounting Policies

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

Joint Arrangements

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

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

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

Exploration and Evaluation Assets

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

Identification of CGUs

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

Key Sources of Estimation Uncertainty

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

Crude Oil and Natural Gas Reserves

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

Impairment of Assets

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

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

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

Crude Oil and Natural Gas Prices

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

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

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

Discount and Inflation Rates

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

Decommissioning Costs

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

Income Tax Provisions

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

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

Changes in Accounting Policies

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

Future Accounting Pronouncements

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

Leases

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

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

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

Revenue Recognition

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

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

Financial Instruments

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

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

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

CONTROL ENVIRONMENT

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

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

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

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

CORPORATE RESPONSIBILITY

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

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

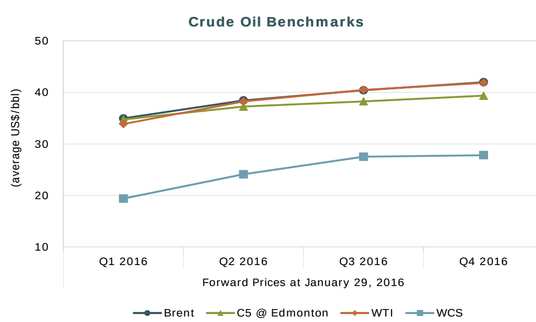
OUTLOOK

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

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

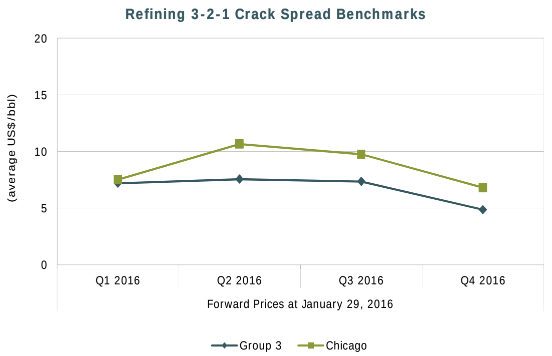
Commodity Prices Underlying our Financial Results

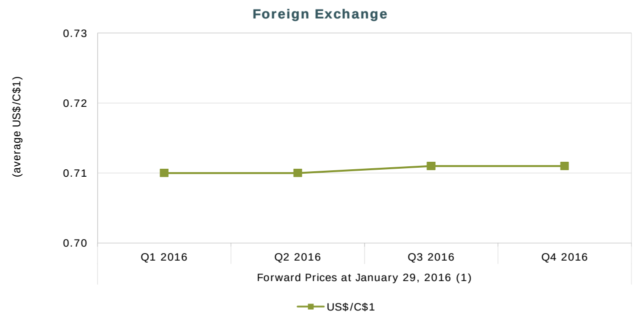
Our crude oil pricing outlook is influenced by the following:



- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment and the pace of growth of the global economy. Overall, we expect crude oil price volatility and a modest price improvement in 2016. Slower global supply growth, combined with annual increases in demand growth, should support prices in the second half of the year, constrained by the need to draw down surplus crude oil inventories and anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The low crude oil price environment also serves to help boost global economic momentum.

  We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production, which will depress crude oil prices, and that economic uncertainty in China may slow emerging market demand;
- We expect the Brent-WTI differential to remain narrow now that the U.S. has lifted restrictions on exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We also expect that the WTI-WCS differential will remain wide due to additional Canadian supply growth and declining U.S. light tight oil supply. However, substantially wider differentials are unlikely due to excess rail capacity and further expansions on existing pipeline systems.





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

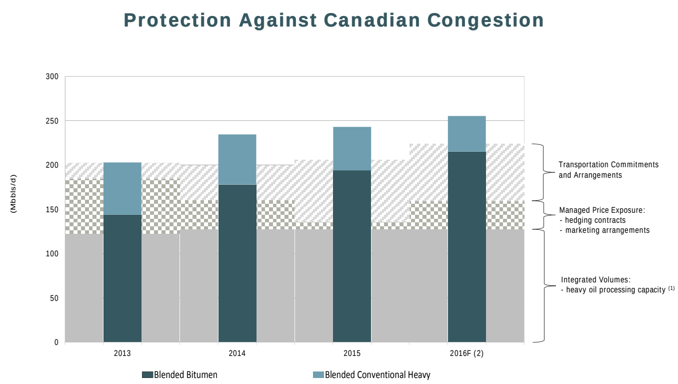
Refining crack spreads in 2016, as forecasted at January 29, 2016, are expected to strengthen late in the second quarter due to higher seasonal demand for refined products and then decline in the second half of the year.

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

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

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

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



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

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience continues to be a top priority. At December 31, 2015, we had $4.1 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 16 years, with no debt maturing until the fourth quarter of 2019. We also have Canadian and U.S. base shelf prospectuses, the availability of which is dependent on market conditions and our credit ratings. Although we have a strong balance sheet, we plan to undertake additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs, as we anticipate commodity prices to remain low in the upcoming year.

Attack Cost Structures

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

We believe we are positioned to achieve additional sustainable cost reductions going forward. We anticipate capital investment in 2016 of $1.2 billion to $1.3 billion, a reduction of $200 million to $300 million from our original budget announced in December 2015. We are targeting $100 million to $200 million of further savings in operating, general and administrative and compensation costs. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

Disciplined and Value-added Growth

We are committed to exercising capital discipline. We will consider expanding existing projects and developing emerging opportunities only when we believe we will generate attractive potential returns for shareholders. Although we have some of the needed fiscal and regulatory clarity at the provincial level, additional certainty around federal fiscal and regulatory regimes, commodity prices and our ability to sustain cost reductions is required. We will only commit to project reactivation if it does not undermine the strength of our balance sheet.

ADVISORY

Oil and Gas Information

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

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

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

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

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

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

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

Forward-looking Information

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

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

2016 guidance, as updated on February 11, 2016, assumes: Brent of US$52.75/bbl, WTI of US$49.00/bbl; WCS of US$34.50/bbl; NYMEX of US$2.50/MMBtu; AECO of $2.50/GJ; Chicago 3-2-1 crack spread of US$12.00/bbl; and an exchange rate of $0.75 US$/C$.

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

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

ABBREVIATIONS

The following abbreviations have been used in this document:

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

Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2015

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2015

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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 four 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, 2015. 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, 2015.

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, 2015, as stated in their Report of Independent Registered Public Accounting Firm dated February 10, 2016. 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 10, 2016

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, 2015 and December 31, 2014 and the Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2015. We also have audited Cenovus Energy Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("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, 2015 and December 31, 2014 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015 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, 2015, 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 10, 2016

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31,
($ millions, except per share amounts)

	Notes	2015	2014	2013
Revenues	1			
Gross Sales		13,207	20,107	18,993
Less: Royalties		143	465	336
		13,064	19,642	18,657
Expenses	1			
Purchased Product		7,374	10,955	10,399
Transportation and Blending		2,043	2,477	2,074
Operating		1,839	2,045	1,782
Production and Mineral Taxes		18	46	35
(Gain) Loss on Risk Management	31	(461)	(662)	293
Depreciation, Depletion and Amortization	9,16	2,114	1,946	1,833
Goodwill Impairment	9	-	497	-
Exploration Expense	9,15	138	86	114
General and Administrative		335	379	365
Finance Costs	5	482	445	529
Interest Income	6	(28)	(33)	(96)
Foreign Exchange (Gain) Loss, Net	7	1,036	411	208
Research Costs		27	15	24
(Gain) Loss on Divestiture of Assets	8	(2,392)	(156)	1
Other (Income) Loss, Net		2	(4)	2
Earnings Before Income Tax		537	1,195	1,094
Income Tax Expense (Recovery)	10	(81)	451	432
Net Earnings		618	744	662
Net Earnings Per Share	11			
Basic		$0.75	$0.98	$0.88
Diluted		$0.75	$0.98	$0.87

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31,
($ millions)

		2015	2014	2013
Net Earnings		618	744	662
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		20	(18)	14
Items That May be Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		6	-	10
Foreign Currency Translation Adjustment		587	215	117
Total Other Comprehensive Income, Net of Tax		613	197	141
Comprehensive Income		1,231	941	803

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	2015	2014
Assets			
Current Assets			
Cash and Cash Equivalents	12	**4,105**	883
Accounts Receivable and Accrued Revenues	13	**1,251**	1,582
Income Tax Receivable		**6**	28
Inventories	14	**810**	1,224
Risk Management	31,32	**301**	478
Current Assets		**6,473**	4,195
Exploration and Evaluation Assets	1,15	**1,575**	1,625
Property, Plant and Equipment, Net	1,16	**17,335**	18,563
Income Tax Receivable		**90**	-
Other Assets	18	**76**	70
Goodwill	1,19	**242**	242
Total Assets		**25,791**	24,695
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	20	**1,702**	2,588
Income Tax Payable		**133**	357
Risk Management	31,32	**23**	12
Current Liabilities		**1,858**	2,957
Long-Term Debt	21	**6,525**	5,458
Risk Management	31,32	**7**	4
Decommissioning Liabilities	22	**2,052**	2,616
Other Liabilities	23	**142**	172
Deferred Income Taxes	10	**2,816**	3,302
Total Liabilities		**13,400**	14,509
Shareholders' Equity		**12,391**	10,186
Total Liabilities and Shareholders' Equity		**25,791**	24,695
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
Balance as at December 31, 2012	3,829	4,154	1,730	69	9,782
Net Earnings	-	-	662	-	662
Other Comprehensive Income (Loss)	-	-	-	141	141
Total Comprehensive Income (Loss)	-	-	662	141	803
Common Shares Issued Under Stock Option Plans	31	-	-	-	31
Common Shares Cancelled	(3)	3	-	-	-
Stock-Based Compensation Expense	-	62	-	-	62
Dividends on Common Shares	-	-	(732)	-	(732)
Balance as at December 31, 2013	3,857	4,219	1,660	210	9,946
Net Earnings	-	-	744	-	744
Other Comprehensive Income (Loss)	-	-	-	197	197
Total Comprehensive Income (Loss)	-	-	744	197	941
Common Shares Issued Under Stock Option Plans	32	-	-	-	32
Stock-Based Compensation Expense	-	72	-	-	72
Dividends on Common Shares	-	-	(805)	-	(805)
Balance as at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings	-	-	618	-	618
Other Comprehensive Income (Loss)	-	-	-	613	613
Total Comprehensive Income (Loss)	-	-	618	613	1,231
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Common Shares Issued Under Stock Option Plans	-	-	-	-	-
Stock-Based Compensation Expense	-	39	-	-	39
Dividends on Common Shares	-	-	(710)	-	(710)
Balance as at December 31, 2015	**5,534**	**4,330**	**1,507**	**1,020**	**12,391**

(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	2015	2014	2013
Operating Activities				
Net Earnings		618	744	662
Depreciation, Depletion and Amortization	9,16	2,114	1,946	1,833
Goodwill Impairment	9	-	497	-
Exploration Expense	9,15	138	86	50
Deferred Income Taxes	10	(655)	359	244
Unrealized (Gain) Loss on Risk Management	31	195	(596)	415
Unrealized Foreign Exchange (Gain) Loss	7	1,097	411	40
(Gain) Loss on Divestiture of Assets	8	(2,392)	(156)	1
Current Tax on Divestiture of Assets	8	391	-	-
Unwinding of Discount on Decommissioning Liabilities	5,22	126	120	97
Other		59	68	267
Net Change in Other Assets and Liabilities		(107)	(135)	(120)
Net Change in Non-Cash Working Capital		(110)	182	50
Cash From Operating Activities		1,474	3,526	3,539
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	15	(138)	(279)	(331)
Capital Expenditures – Property, Plant and Equipment	16	(1,576)	(2,779)	(2,938)
Acquisition	17	(84)	-	-
Proceeds From Divestiture of Assets	8	3,344	276	258
Current Tax on Divestiture of Assets	8	(391)	-	-
Net Change in Investments and Other		3	(1,583)	1,486
Net Change in Non-Cash Working Capital		(270)	15	6
Cash From (Used in) Investing Activities		888	(4,350)	(1,519)
Net Cash Provided (Used) Before Financing Activities		2,362	(824)	2,020
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		(25)	(18)	(8)
Issuance of U.S. Unsecured Notes	21	-	-	814
Repayment of U.S. Unsecured Notes	21	-	-	(825)
Common Shares Issued, Net of Issuance Costs	25	1,449	-	-
Common Shares Issued Under Stock Option Plans		-	28	28
Dividends Paid on Common Shares	11	(528)	(805)	(732)
Other		(2)	(2)	(3)
Cash From (Used in) Financing Activities		894	(797)	(726)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		(34)	52	(2)
Increase (Decrease) in Cash and Cash Equivalents		3,222	(1,569)	1,292
Cash and Cash Equivalents, Beginning of Year		883	2,452	1,160
Cash and Cash Equivalents, End of Year		4,105	883	2,452
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 cash flow. The Company's reportable segments are:

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

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,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,030**	5,036	3,912	**1,709**	3,225	2,980	**8,805**	12,658	12,706
Less: Royalties	**29**	236	132	**114**	229	204	**-**	-	-
	3,001	4,800	3,780	**1,595**	2,996	2,776	**8,805**	12,658	12,706
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**7,709**	11,767	11,004
Transportation and Blending	**1,815**	2,131	1,749	**230**	346	325	**-**	-	-
Operating	**531**	639	548	**561**	709	701	**754**	703	538
Production and Mineral Taxes	**-**	-	-	**18**	46	35	**-**	-	-
(Gain) Loss on Risk Management	**(404)**	(38)	(37)	**(209)**	(1)	(104)	**(43)**	(27)	19
Operating Cash Flow	**1,059**	2,068	1,520	**995**	1,896	1,819	**385**	215	1,145
Depreciation, Depletion and Amortization	**697**	625	446	**1,148**	1,082	1,170	**191**	156	138
Goodwill Impairment	**-**	-	-	**-**	497	-	**-**	-	-
Exploration Expense	**67**	4	-	**71**	82	114	**-**	-	-
Segment Income (Loss)	**295**	1,439	1,074	**(224)**	235	535	**194**	59	1,007

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Revenues						
Gross Sales	**(337)**	(812)	(605)	**13,207**	20,107	18,993
Less: Royalties	**-**	-	-	**143**	465	336
	(337)	(812)	(605)	**13,064**	19,642	18,657
Expenses						
Purchased Product	**(335)**	(812)	(605)	**7,374**	10,955	10,399
Transportation and Blending	**(2)**	-	-	**2,043**	2,477	2,074
Operating	**(7)**	(6)	(5)	**1,839**	2,045	1,782
Production and Mineral Taxes	**-**	-	-	**18**	46	35
(Gain) Loss on Risk Management	**195**	(596)	415	**(461)**	(662)	293
Depreciation, Depletion and Amortization	**78**	83	79	**2,114**	1,946	1,833
Goodwill Impairment	**-**	-	-	**-**	497	-
Exploration Expense	**-**	-	-	**138**	86	114
Segment Income (Loss)	**(266)**	519	(489)	**(1)**	2,252	2,127
General and Administrative	**335**	379	365	**335**	379	365
Finance Costs	**482**	445	529	**482**	445	529
Interest Income	**(28)**	(33)	(96)	**(28)**	(33)	(96)
Foreign Exchange (Gain) Loss, Net	**1,036**	411	208	**1,036**	411	208
Research Costs	**27**	15	24	**27**	15	24
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	1	**(2,392)**	(156)	1
Other (Income) Loss, Net	**2**	(4)	2	**2**	(4)	2
	(538)	1,057	1,033	**(538)**	1,057	1,033
Earnings Before Income Tax				**537**	1,195	1,094
Income Tax Expense (Recovery)				**(81)**	451	432
Net Earnings				**618**	744	662

B) Financial Results by Upstream Product

Crude Oil [1]

	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,000**	4,963	3,850	**1,239**	2,456	2,373	**4,239**	7,419	6,223
Less: Royalties	**29**	233	131	**103**	217	196	**132**	450	327
	2,971	4,730	3,719	**1,136**	2,239	2,177	**4,107**	6,969	5,896
Expenses									
Transportation and Blending	**1,814**	2,130	1,748	**213**	326	305	**2,027**	2,456	2,053
Operating	**511**	615	527	**381**	505	489	**892**	1,120	1,016
Production and Mineral Taxes	**-**	-	-	**16**	37	32	**16**	37	32
(Gain) Loss on Risk Management	**(400)**	(38)	(33)	**(157)**	4	(43)	**(557)**	(34)	(76)
Operating Cash Flow	**1,046**	2,023	1,477	**683**	1,367	1,394	**1,729**	3,390	2,871

(1) Includes NGLs.

Natural Gas

	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**22**	67	38	**450**	744	594	**472**	811	632
Less: Royalties	**-**	3	1	**11**	12	8	**11**	15	9
	22	64	37	**439**	732	586	**461**	796	623
Expenses									
Transportation and Blending	**1**	1	1	**17**	20	20	**18**	21	21
Operating	**15**	17	18	**175**	198	208	**190**	215	226
Production and Mineral Taxes	**-**	-	-	**2**	9	3	**2**	9	3
(Gain) Loss on Risk Management	**(4)**	-	(4)	**(52)**	(5)	(61)	**(56)**	(5)	(65)
Operating Cash Flow	**10**	46	22	**297**	510	416	**307**	556	438

Other

	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**8**	6	24	**20**	25	13	**28**	31	37
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
	8	6	24	**20**	25	13	**28**	31	37
Expenses									
Transportation and Blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**5**	7	3	**5**	6	4	**10**	13	7
Production and Mineral Taxes	**-**	-	-	**-**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**3**	(1)	21	**15**	19	9	**18**	18	30

Total Upstream

	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,030**	5,036	3,912	**1,709**	3,225	2,980	**4,739**	8,261	6,892
Less: Royalties	**29**	236	132	**114**	229	204	**143**	465	336
	3,001	4,800	3,780	**1,595**	2,996	2,776	**4,596**	7,796	6,556
Expenses									
Transportation and Blending	**1,815**	2,131	1,749	**230**	346	325	**2,045**	2,477	2,074
Operating	**531**	639	548	**561**	709	701	**1,092**	1,348	1,249
Production and Mineral Taxes	**-**	-	-	**18**	46	35	**18**	46	35
(Gain) Loss on Risk Management	**(404)**	(38)	(37)	**(209)**	(1)	(104)	**(613)**	(39)	(141)
Operating Cash Flow	**1,059**	2,068	1,520	**995**	1,896	1,819	**2,054**	3,964	3,339

C) Geographic Information

For the years ended December 31,	Canada 2015	Canada 2014	Canada 2013	United States 2015	United States 2014	United States 2013	Consolidated 2015	Consolidated 2014	Consolidated 2013
Revenues									
Gross Sales	**6,407**	10,604	8,943	**6,800**	9,503	10,050	**13,207**	20,107	18,993
Less: Royalties	**143**	465	336	**-**	-	-	**143**	465	336
	6,264	10,139	8,607	**6,800**	9,503	10,050	**13,064**	19,642	18,657
Expenses									
Purchased Product	**1,607**	2,310	2,022	**5,767**	8,645	8,377	**7,374**	10,955	10,399
Transportation and Blending	**2,043**	2,477	2,074	**-**	-	-	**2,043**	2,477	2,074
Operating	**1,129**	1,367	1,260	**710**	678	522	**1,839**	2,045	1,782
Production and Mineral Taxes	**18**	46	35	**-**	-	-	**18**	46	35
(Gain) Loss on Risk Management	**(435)**	(625)	275	**(26)**	(37)	18	**(461)**	(662)	293
Depreciation, Depletion and Amortization	**1,925**	1,790	1,695	**189**	156	138	**2,114**	1,946	1,833
Goodwill Impairment	**-**	497	-	**-**	-	-	**-**	497	-
Exploration Expense	**138**	86	114	**-**	-	-	**138**	86	114
Segment Income (Loss)	**(161)**	2,191	1,132	**160**	61	995	**(1)**	2,252	2,127

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 $870 million (2014 – $821 million; 2013 – $926 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, 2015, Cenovus had three customers (2014 – three; 2013 – 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 $4,647 million, $1,705 million and $1,545 million, respectively (2014 – $7,210 million, $2,668 million and $2,316 million; 2013 – $7,032 million, $2,711 million and $1,799 million), which are included in all of the Company's segments.

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

By Segment

As at December 31,	E&E (1) 2015	E&E (1) 2014	PP&E (2) 2015	PP&E (2) 2014	Goodwill 2015	Goodwill 2014	Total Assets 2015	Total Assets 2014
Oil Sands	**1,560**	1,540	**8,907**	8,606	**242**	242	**11,069**	11,024
Conventional	**15**	85	**3,720**	6,038	**-**	-	**3,830**	6,211
Refining and Marketing	**-**	-	**4,398**	3,568	**-**	-	**5,844**	5,520
Corporate and Eliminations	**-**	-	**310**	351	**-**	-	**5,048**	1,940
Consolidated	**1,575**	1,625	**17,335**	18,563	**242**	242	**25,791**	24,695

(1) Exploration and evaluation ("E&E") assets.
(2) Property, plant and equipment ("PP&E").

By Geographic Region

	E&E		PP&E		Goodwill		Total Assets	
As at December 31,	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Canada	**1,575**	1,625	**13,028**	14,999	**242**	242	**20,627**	20,231
United States	**-**	-	**4,307**	3,564	**-**	-	**5,164**	4,464
Consolidated	**1,575**	1,625	**17,335**	18,563	**242**	242	**25,791**	24,695

E) Capital Expenditures [(1)]

For the years ended December 31,	**2015**	2014	2013
Capital			
Oil Sands	**1,185**	1,986	1,885
Conventional	**244**	840	1,189
Refining and Marketing	**248**	163	107
Corporate	**37**	62	81
	1,714	3,051	3,262
Acquisition Capital			
Oil Sands	**3**	15	27
Conventional	**1**	3	5
Refining and Marketing	**83**	-	-
	1,801	3,069	3,294

(1) *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 of Cenovus were approved by the Board of Directors on February 10, 2016.

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 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 the 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 discounted 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, 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 within PP&E.

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, available for sale financial assets 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 assets 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 the 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 2015. Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense. As a result, for the years ended December 31, 2014 and 2013, expenses of $21 million and $16 million, respectively, were reclassified.

U) Recent Accounting Pronouncements

New and Amended Accounting Standards and Interpretations Adopted

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2015.

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, 2016 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2015. 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 Company is currently evaluating the impact of adopting IFRS 16 on the Consolidated Financial Statements.

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing 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.

Financial Instruments

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

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. 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 is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

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 partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of 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 interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of 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.

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 independent qualified reserves evaluators.

Impairment of Assets

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 judgement to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

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,	2015	2014	2013
Interest Expense – Short-Term Borrowings and Long-Term Debt	328	285	271
Premium on Redemption of Long-Term Debt	-	-	33
Unwinding of Discount on Decommissioning Liabilities (Note 22)	126	120	97
Other	28	18	30
Interest Expense – Partnership Contribution Payable [1]	-	22	98
	482	445	529

(1) In 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.

6. INTEREST INCOME

For the years ended December 31,	2015	2014	2013
Interest Income – Partnership Contribution Receivable [1]	-	-	(82)
Other	(28)	(33)	(14)
	(28)	(33)	(96)

(1) In 2013, Cenovus received the remaining principal and accrued interest due under the Partnership Contribution Receivable.

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2015	2014	2013
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	1,064	458	357
U.S. Dollar Partnership Contribution Receivable Issued From Canada	-	-	(305)
Other	33	(47)	(12)
Unrealized Foreign Exchange (Gain) Loss	1,097	411	40
Realized Foreign Exchange (Gain) Loss	(61)	-	168
	1,036	411	208

8. DIVESTITURES

On July 29, 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 is a royalty business consisting of approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. Cenovus entered into lease agreements with HRP on the fee lands from which it currently has working interest production.

In addition, HRP has a Gross Overriding Royalty on production from Cenovus's Pelican Lake and Weyburn assets. These assets and results of operations were reported in the Conventional segment.

The divestiture gave rise to a taxable gain for which the Company has recognized 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 is 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.

In 2013, the Company completed the sale of the Lower Shaunavon asset to an unrelated third party for net proceeds of $241 million, resulting in a loss of $2 million. These assets and results of operations were reported in the Conventional segment. Other divestitures in 2013 included undeveloped land in northern Alberta, cancellation of some of the Company's non-core Oil Sands mineral rights under the Lower Athabasca Regional Plan and a third-party land exchange.

9. IMPAIRMENTS

A) Cash-Generating Unit Impairments

As indicators of impairment were noted due to the significant decline in forward commodity prices, the Company has tested its upstream CGUs for impairment.

Key Assumptions

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

Crude Oil and Natural Gas Prices

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

	2016	2017	2018	2019	2020	Average Annual % Change to 2026
WTI (US$/barrel) (1)	45.00	53.60	62.40	69.00	73.10	3.8%
WCS (C$/barrel) (2)	46.40	54.40	59.70	66.30	68.20	3.9%
AECO (C$/Mcf) (3) (4)	2.70	3.20	3.55	3.85	3.95	4.0%

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

Discount and Inflation Rates

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

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. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage. Future cash flows for the 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 fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with Cenovus's independent qualified reserves evaluators (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no impairments of goodwill in the year ended December 31, 2015.

Sensitivities

Changes to the assumed discount rate or forward price estimates over the life of the reserves independently would have the following impact on the 2015 impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Price Estimates
Increase to Impairment of PP&E	157	336

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 fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with Cenovus's independent qualified reserves evaluators (Level 3). 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.

2013 Impairments

There were no CGU impairments for the year ended December 31, 2013.

B) Asset Impairments

Exploration and Evaluation Assets

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.

In 2013, $50 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.

Property, Plant and Equipment, Net

In addition to the impairments recorded at the CGU level, DD&A expense includes the following asset impairments:

For the years ended December 31,	**2015**	2014	2013
Development and Production (Note 16)	**16**	65	59
	16	65	59

In 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded 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 fair value less costs of disposal. Additionally, a minor natural gas property was shut-in and abandonment commenced, resulting in an impairment of $13 million. These impairments were recorded in the Conventional segment.

In 2013, the Company impaired its Lower Shaunavon asset for $57 million prior to its divestiture. The impairment was recorded in the Conventional segment.

10. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2015**	2014	2013
Current Tax			
Canada	**586**	94	143
United States	**(12)**	(2)	45
Total Current Tax Expense (Recovery)	**574**	92	188
Deferred Tax Expense (Recovery)	**(655)**	359	244
	(81)	451	432

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the Company's 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 Alberta government 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 Canadian statutory tax rate as at December 31, 2015 was 27.0 percent. The U.S. statutory tax rate has decreased to 38.0 percent from 38.1 percent in 2014 and 38.5 percent in 2013.

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

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

The analysis of deferred income tax liabilities and deferred income tax assets is:

As at December 31,	2015	2014
Net Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**58**	296
Deferred Tax Liabilities to be Settled After More Than 12 Months	**2,758**	3,006
	2,816	3,302

For the purposes of the preceding table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where they occur in the same entity and jurisdiction. The deferred income tax 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, 2013	3,000	88	2	152	3,242
Charged/(Credited) to Earnings	22	79	119	(111)	109
Charged/(Credited) to OCI	84	-	-	-	84
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**

Deferred Income Tax Assets	Unused Tax Losses	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2013	(104)	-	(35)	(241)	(380)
Charged/(Credited) to Earnings	41	-	31	178	250
Charged/(Credited) to OCI	(9)	-	-	6	(3)
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)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2013	2,862
Charged/(Credited) to Earnings	359
Charged/(Credited) to OCI	81
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**

No deferred tax liability has been recognized as at December 31, 2015 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, 2015, the Company had temporary differences of $6,692 million (2014 – $6,667 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 are:

As at December 31,	2015	2014
Canada	**4,882**	6,153
United States	**2,119**	958
	7,001	7,111

As at December 31, 2015, the above tax pools included $13 million (2014 – $8 million) of Canadian non-capital losses and $380 million (2014 – $140 million) of U.S. federal net operating losses. These losses expire no earlier than 2031.

Also included in the December 31, 2015 tax pools are Canadian net capital losses totaling $44 million (2014 – $593 million), which are available for carry forward to reduce future capital gains. Of these losses, $41 million are unrecognized as a deferred income tax asset as at December 31, 2015 (2014 – $559 million). Recognition is dependent on future capital gains. The Company has not recognized $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 Per Share

For the years ended December 31,	2015	2014	2013
Net Earnings – Basic and Diluted ($ millions)	**618**	744	662
Basic – Weighted Average Number of Shares (millions)	**818.7**	756.9	755.9
Dilutive Effect of Cenovus TSARs	**-**	0.7	1.6
Dilutive Effect of Cenovus NSRs	**-**	-	-
Diluted – Weighted Average Number of Shares	**818.7**	757.6	757.5
Net Earnings Per Share ($)			
Basic	**$0.75**	$0.98	$0.88
Diluted	**$0.75**	$0.98	$0.87

B) Dividends Per Share

For the year ended December 31, 2015, the Company paid dividends of $710 million or $0.8524 per share (2014 – $805 million, $1.0648 per share; 2013 – $732 million, $0.968 per share), including cash dividends of $528 million. For 2014 and 2013, all dividends were paid in cash. The Cenovus Board of Directors declared a first quarter dividend of $0.05 per share, payable on March 31, 2016, to common shareholders of record as of March 15, 2016.

12. CASH AND CASH EQUIVALENTS

As at December 31,	2015	2014
Cash	**323**	458
Short-Term Investments	**3,782**	425
	4,105	883

13. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	2015	2014
Accruals	**1,037**	1,417
Partner Advances	**35**	44
Prepaids and Deposits	**71**	56
Trade	**61**	6
Joint Operations Receivables	**13**	18
Other	**34**	41
	1,251	1,582

14. INVENTORIES

As at December 31,	2015	2014
Product		
Refining and Marketing	**591**	972
Oil Sands	**158**	182
Conventional	**11**	28
Parts and Supplies	**50**	42
	810	1,224

During the year ended December 31, 2015, approximately $10,618 million of produced and purchased inventory was recorded as an expense (2014 – $15,065 million; 2013 – $13,895 million).

As a result of a decline in commodity prices, Cenovus recorded a write-down of its product inventory of $66 million from cost to net realizable value as at December 31, 2015 (2014 – $131 million).

15. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E (Note 16)	(53)
Exploration Expense (Note 9)	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
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**

16. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2013	29,390	286	3,654	849	34,179
Additions	2,522	43	162	63	2,790
Transfers From E&E Assets (Note 15)	53	-	-	-	53
Transfers to Assets Held for Sale	(55)	-	-	-	(55)
Change in Decommissioning Liabilities	264	-	(3)	-	261
Exchange Rate Movements and Other	1	-	338	-	339
Divestitures	(474)	-	-	(2)	(476)
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 8)	(923)	-	-	-	(923)
As at December 31, 2015	**31,481**	**331**	**5,206**	**1,037**	**38,055**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2013	15,791	193	386	475	16,845
Depreciation, Depletion and Amortization	1,602	40	156	83	1,881
Transfers to Assets Held for Sale	(27)	-	-	-	(27)
Impairment Losses (Note 9)	65	-	-	-	65
Exchange Rate Movements and Other	38	-	42	-	80
Divestitures	(316)	-	-	-	(316)
As at December 31, 2014	17,153	233	584	558	18,528
Depreciation, Depletion and Amortization	1,601	44	189	80	1,914
Impairment Losses (Note 9)	200	-	-	-	200
Exchange Rate Movements and Other	(1)	-	123	1	123
Divestitures (Note 8)	(45)	-	-	-	(45)
As at December 31, 2015	**18,908**	**277**	**896**	**639**	**20,720**
CARRYING VALUE					
As at December 31, 2013	13,599	93	3,268	374	17,334
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**

(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,	2015	2014
Development and Production	**537**	478
Refining Equipment	**265**	159
	802	637

17. ACQUISITION

On August 31, 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 have been expensed. These assets and results of operations are reported in the Refining and Marketing segment.

18. OTHER ASSETS

As at December 31,	2015	2014
Investments	46	36
Long-Term Receivables	1	7
Prepaids	7	7
Other	22	20
	76	70

19. GOODWILL

As at December 31,	2015	2014
Carrying Value, Beginning of Year	242	739
Impairment Losses (Note 9)	-	(497)
Carrying Value, End of Year	242	242

All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. As at December 31, 2015 and 2014, the carrying amount of goodwill was associated with the Company's Primrose (Foster Creek) CGU.

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	2015	2014
Accruals	1,366	2,057
Partner Advances	35	218
Trade	68	51
Employee Long-Term Incentives	47	91
Interest	73	61
Other	113	110
	1,702	2,588

21. LONG-TERM DEBT

As at December 31,		2015	2014
Revolving Term Debt [1]	A	-	-
U.S. Dollar Denominated Unsecured Notes	B	6,574	5,510
Total Debt Principal	C	6,574	5,510
Debt Discounts and Transaction Costs	D	(49)	(52)
		6,525	5,458

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

The weighted average interest rate on outstanding debt for the year ended December 31, 2015 was 5.3 percent (2014 – 5.0 percent).

A) Revolving Term Debt

As at December 31, 2015, Cenovus had in place a committed credit facility in the amount of $4.0 billion or the equivalent amount in U.S. dollars. During the second quarter of 2015, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. 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, 2015, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2014 – $nil).

B) Unsecured Notes

Unsecured notes are composed of:

As at December 31,	US$ Principal Amount	**2015**	2014
5.70% due October 15, 2019	1,300	**1,799**	1,508
3.00% due August 15, 2022	500	**692**	580
3.80% due September 15, 2023	450	**623**	522
6.75% due November 15, 2039	1,400	**1,938**	1,624
4.45% due September 15, 2042	750	**1,038**	870
5.20% due September 15, 2043	350	**484**	406
		6,574	5,510

On June 24, 2014, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2015, no notes have been issued under this U.S. base shelf prospectus. The U.S. base shelf prospectus expires in July 2016.

On June 25, 2014, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2015, no medium term notes have been issued under this Canadian base shelf prospectus. The Canadian base shelf prospectus expires in July 2016.

As at December 31, 2015, 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**
2016	-	-	**-**
2017	-	-	**-**
2018	-	-	**-**
2019	1,300	-	**1,799**
2020	-	-	**-**
Thereafter	3,450	-	**4,775**
	4,750	-	**6,574**

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 2015, additional transaction costs of $3 million were recorded (2014 – $2 million).

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,	2015	2014
Decommissioning Liabilities, Beginning of Year	2,616	2,370
Liabilities Incurred	10	48
Liabilities Acquired	4	-
Liabilities Settled	(62)	(93)
Liabilities Divested	-	(60)
Transfers and Reclassifications	-	(9)
Change in Estimated Future Cash Flows	(70)	115
Change in Discount Rate	(579)	122
Unwinding of Discount on Decommissioning Liabilities	126	120
Foreign Currency Translation	7	3
Decommissioning Liabilities, End of Year	2,052	2,616

The undiscounted amount of estimated future cash flows required to settle the obligation is $6,665 million (December 31, 2014 – $8,333 million), which has been discounted using a credit-adjusted risk-free rate of 6.4 percent (December 31, 2014 – 4.9 percent). An inflation rate of two percent (2014 – 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 $35 million to $70 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:

	2015		2014	
As at December 31,	Credit-Adjusted Risk-Free Rate	Inflation Rate	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	(247)	319	(419)	574
One Percent Decrease	308	(259)	562	(433)

23. OTHER LIABILITIES

As at December 31,	2015	2014
Employee Long-Term Incentives	40	57
Pension and OPEB (Note 24)	66	84
Other	36	31
	142	172

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,	**2015**	2014	**2015**	2014
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**200**	148	**23**	18
Current Service Costs	**19**	15	**3**	2
Interest Costs (1)	**8**	7	**1**	1
Benefits Paid	**(6)**	(3)	**(1)**	-
Plan Participant Contributions	**3**	3	**-**	-
Past Service Costs – Curtailments	**(5)**	-	**-**	-
Settlements	**(20)**	-	**-**	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	**(3)**	-	**-**	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	(1)	**-**	-
(Gains) Losses from Changes in Financial Assumptions	**(28)**	31	**-**	2
Defined Benefit Obligation, End of Year	**168**	200	**26**	23
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**139**	115	**-**	-
Employer Contributions	**16**	12	**-**	-
Plan Participant Contributions	**3**	3	**-**	-
Benefits Paid	**(6)**	(3)	**-**	-
Settlements	**(23)**	-	**-**	-
Interest Income (1)	**2**	4	**-**	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**(3)**	8	**-**	-
Fair Value of Plan Assets, End of Year	**128**	139	**-**	-
Pension and Other Post-Employment Benefit (Liability) (2)	**(40)**	(61)	**(26)**	(23)

(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 15 years and 12 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Defined Benefit Plan Cost						
Current Service Costs	**19**	15	17	**3**	2	2
Past Service Costs – Curtailments	**(5)**	-	-	**-**	-	-
Net Settlement Costs	**3**	-	-	**-**	-	-
Net Interest Costs	**6**	3	4	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**3**	(8)	(7)	**-**	-	-
(Gains) Losses from Experience Adjustments	**(3)**	-	1	**-**	-	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	(1)	12	**-**	-	(1)
(Gains) Losses from Changes in Financial Assumptions	**(28)**	31	(19)	**-**	2	(4)
Defined Benefit Plan Cost (Gain)	**(5)**	40	8	**4**	5	(2)
Defined Contribution Plan Cost	**29**	30	27	**-**	-	-
Total Plan Cost	**24**	70	35	**4**	5	(2)

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 monthly and is re-balanced as necessary. The asset allocation structure targets an investment of 60 to 70 percent in equity securities, 30 percent in debt instruments and the remainder invested in real estate and other.

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,	**2015**	2014
Equity Securities		
Equity Funds and Balanced Funds	**73**	75
Other	**3**	9
Bond Funds	**31**	36
Non-Invested Assets	**17**	15
Real Estate	**4**	4
	128	139

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 real estate is determined by accredited real estate appraisers.

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 the most recent actuarial valuation as at December 31, 2014, and direction by 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, 2016 are $15 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,	**2015**	2014	2013	**2015**	2014	2013
Discount Rate	**4.00%**	3.75%	4.75%	**3.75%**	3.75%	4.75%
Future Salary Growth Rate	**3.80%**	4.32%	4.39%	**5.15%**	5.65%	5.65%
Average Longevity (Years)	**88.3**	88.3	88.5	**88.3**	88.3	88.5
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 shown below.

	2015		2014	
As at December 31,	**One Percentage Point Increase**	**One Percentage Point Decrease**	One Percentage Point Increase	One Percentage Point Decrease
Discount Rate	**(27)**	**35**	(34)	43
Future Salary Growth Rate	**3**	**(3)**	4	(4)
Health Care Cost Trend Rate	**2**	**(2)**	2	(2)
Future Mortality Rate (Years)	**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

	2015		2014	
As at December 31,	Number of Common Shares (Thousands)	Amount	Number of Common Shares (Thousands)	Amount
Outstanding, Beginning of Year	757,103	3,889	756,046	3,857
Common Shares Issued, Net of Issuance Costs	67,500	1,463	-	-
Common Shares Issued Pursuant to Dividend Reinvestment Plan	8,687	182	-	-
Common Shares Issued Under Stock Option Plans	-	-	1,057	32
Outstanding, End of Year	833,290	5,534	757,103	3,889

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 of the Company or purchased on the market. During the year ended December 31, 2015, the Company issued 8.7 million common shares from treasury under the DRIP.

There were no preferred shares outstanding as at December 31, 2015 (2014 – nil).

As at December 31, 2015, there were 12 million (2014 – 13 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. 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, 2013	4,086	133	4,219
Stock-Based Compensation Expense	-	72	72
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**

26. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at December 31, 2013	(12)	212	10	210
Other Comprehensive Income (Loss), Before Tax	(24)	215	-	191
Income Tax	6	-	-	6
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**

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 under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights 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.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, 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.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("performance TSARs"). All performance TSARs have vested, and, as such, terms and conditions are consistent with TSARs, which were not performance based.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2015 was $3.58 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	0.75%
Expected Dividend Yield	3.60%
Expected Volatility [1]	28.27%
Expected Life (Years)	4.55

(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, 2015	Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	40,549	32.63
Granted	4,106	22.25
Exercised	-	-
Forfeited	(2,541)	32.19
Outstanding, End of Year	42,114	31.65
Exercisable, End of Year	23,484	34.46

	Outstanding NSRs		
As at December 31, 2015 Range of Exercise Price ($)	Number of NSRs (Thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
15.00 to 19.99	6	6.68	18.07
20.00 to 24.99	4,075	6.15	22.26
25.00 to 29.99	14,281	5.14	28.39
30.00 to 34.99	12,642	4.18	32.61
35.00 to 39.99	11,110	2.79	38.19
	42,114	4.33	31.65

	Exercisable NSRs	
As at December 31, 2015 Range of Exercise Price ($)	Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
15.00 to 19.99	-	-
20.00 to 24.99	40	22.99
25.00 to 29.99	4,404	28.41
30.00 to 34.99	7,930	32.64
35.00 to 39.99	11,110	38.19
	23,484	34.46

TSARs

The Company has recorded a liability of $1 million as at December 31, 2015 (December 31, 2014 – $8 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	0.75%
Expected Dividend Yield	4.14%
Expected Volatility [(1)]	29.24%
Cenovus's Common Share Price	$17.50

(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, 2015 was $nil (December 31, 2014 – $nil).

The following tables summarize information related to the TSARs held by Cenovus employees:

As at December 31, 2015	Number of TSARs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	3,862	26.72
Exercised for Cash Payment	-	-
Exercised as Options for Common Shares	-	-
Forfeited	(144)	27.06
Expired	(73)	25.89
Outstanding, End of Year	3,645	26.72
Exercisable, End of Year	3,645	26.72

	Outstanding and Exercisable TSARs		
As at December 31, 2015 Range of Exercise Price ($)	Number of TSARs (Thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	3,497	1.16	26.46
30.00 to 39.99	148	1.98	32.88
	3,645	1.20	26.72

The closing price of Cenovus's common shares on the TSX as at December 31, 2015 was $17.50.

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 $49 million as at December 31, 2015 (2014 – $109 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares as at December 31, 2015. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at December 31, 2015 and 2014.

The following table summarizes the information related to the PSUs held by Cenovus employees:

As at December 31, 2015	**Number of PSUs** (Thousands)
Outstanding, Beginning of Year	**7,099**
Granted	**2,909**
Vested and Paid Out	**(2,176)**
Cancelled	**(1,681)**
Units in Lieu of Dividends	**276**
Outstanding, End of Year	**6,427**

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 $11 million as at December 31, 2015 (2014 – $1 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares as at December 31, 2015. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2015 and 2014.

The following table summarizes the information related to the RSUs held by Cenovus employees:

As at December 31, 2015	**Number of RSUs** (Thousands)
Outstanding, Beginning of Year	**93**
Granted	**2,345**
Vested and Paid Out	**(22)**
Cancelled	**(251)**
Units in Lieu of Dividends	**102**
Outstanding, End of Year	**2,267**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive DSUs, which are equivalent in value to a common share of the Company. 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 $26 million as at December 31, 2015 (2014 – $31 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares as at December 31, 2015. 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, 2015	Number of DSUs (Thousands)
Outstanding, Beginning of Year	**1,297**
Granted to Directors	**68**
Granted	**68**
Units in Lieu of Dividends	**60**
Redeemed	**(5)**
Outstanding, End of Year	**1,488**

E) Total Stock-Based Compensation

For the years ended December 31,	2015	2014	2013
NSRs	**27**	41	35
TSARs	**(5)**	(10)	(16)
PSUs	**(13)**	34	32
RSUs	**6**	-	-
DSUs	**(5)**	(5)	-
Stock-Based Compensation Expense (Recovery)	**10**	60	51
Stock-Based Compensation Costs Capitalized	**6**	29	18
Total Stock-Based Compensation	**16**	89	69

28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2015	2014	2013
Salaries, Bonuses and Other Short-Term Employee Benefits	**534**	550	494
Defined Contribution Pension Plan	**19**	18	17
Defined Benefit Pension Plan and OPEB	**17**	14	15
Stock-Based Compensation Expense (Note 27)	**10**	60	51
Termination Benefits	**43**	-	-
	623	642	577

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,	2015	2014	2013
Salaries, Director Fees and Short-Term Benefits	**30**	29	31
Post-Employment Benefits	**5**	4	4
Stock-Based Compensation	**5**	20	24
	40	53	59

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, current and long-term portions of long-term debt, and the current and long-term portions of the Partnership Contribution Payable, 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,	**2015**	2014	2013
Debt	**6,525**	5,458	4,997
Add (Deduct):			
Cash and Cash Equivalents	**(4,105)**	(883)	(2,452)
Current Portion of Partnership Contribution Payable [1]	**-**	-	438
Partnership Contribution Payable [1]	**-**	-	1,087
Net Debt	**2,420**	4,575	4,070
Debt	**6,525**	5,458	4,997
Shareholders' Equity	**12,391**	10,186	9,946
	18,916	15,644	14,943
Debt to Capitalization	**34%**	35%	33%
Net Debt	**2,420**	4,575	4,070
Shareholders' Equity	**12,391**	10,186	9,946
	14,811	14,761	14,016
Net Debt to Capitalization	**16%**	31%	29%

(1) In 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.

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

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

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

As at December 31, 2015, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus had in place a $1.5 billion Canadian base shelf prospectus and a US$2.0 billion U.S. base shelf prospectus, the availability of which are dependent on market conditions.

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

As at December 31, 2015, Cenovus is in compliance with all of the terms of its debt agreements.

31. FINANCIAL INSTRUMENTS

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

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of those 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, 2015, the carrying value of Cenovus's long-term debt was $6,525 million and the fair value was $6,050 million (2014 carrying value – $5,458 million, fair value – $5,726 million).

Available for sale financial 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,	2015	2014
Fair Value, Beginning of Year	32	32
Acquisition of Investments	2	4
Reclassification of Equity Investments	-	(4)
Change in Fair Value (1)	8	-
Fair Value, End of Year	42	32

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

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, natural gas and power purchase contracts, as well as interest rate swaps. Crude oil, condensate and 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 forward prices used in the determination of the fair value of the power purchase contracts as at December 31, 2015 range from $30.00 to $41.00 per megawatt hour. The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including quoted market prices and interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2015			2014		
	Risk Management			Risk Management		
As at December 31,	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	301	15	286	423	7	416
Natural Gas	-	-	-	55	-	55
Power	-	13	(13)	-	9	(9)
	301	28	273	478	16	462
Interest Rate	-	2	(2)	-	-	-
Total Fair Value	301	30	271	478	16	462

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

As at December 31,	2015	2014
Prices Sourced From Observable Data or Market Corroboration (Level 2)	284	471
Prices Determined From Unobservable Inputs (Level 3)	(13)	(9)
	271	462

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,	**2015**	2014
Fair Value of Contracts, Beginning of Year	**462**	(129)
Fair Value of Contracts Realized During the Year [1]	**(656)**	(66)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year [2]	**461**	662
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**4**	(5)
Fair Value of Contracts, End of Year	**271**	462

(1) Includes a realized loss of $10 million related to power contracts (2014 - $4 million gain).
(2) Includes a decrease of $14 million related to power contracts (2014 - $10 million decrease).

Financial assets and liabilities are only offset 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:

	2015			2014		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**317**	**46**	**271**	479	17	462
Amount Offset	**(16)**	**(16)**	**-**	(1)	(1)	-
Net Amount per Consolidated Financial Statements	**301**	**30**	**271**	478	16	462

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, 2015, $26 million (2014 – $12 million) was pledged as collateral, of which $5 million (2014 – $7 million) could have been withdrawn.

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

For the years ended December 31,	**2015**	2014	2013
Realized (Gain) Loss [1]	**(656)**	(66)	(122)
Unrealized (Gain) Loss [2]	**195**	(596)	415
(Gain) Loss on Risk Management	**(461)**	(662)	293

(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

The Company is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk.

A) 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.

Power – The Company has in place a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Net Fair Value of Risk Management Positions

As at December 31, 2015	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	17,000 bbls/d	January – June 2016	$75.80/bbl	64
Brent Fixed Price	33,000 bbls/d	January – June 2016	US$47.59/bbl	65
Brent Fixed Price	10,000 bbls/d	January – December 2016	US$66.93/bbl	127
Brent Fixed Price	5,000 bbls/d	July – December 2016	$75.46/bbl	13
WCS Differential (1)	31,600 bbls/d	January – December 2016	US$(13.96)/bbl	(9)
Brent Collars	10,000 bbls/d	July – December 2016	US$45.55 – US$56.55/bbl	11
Other Financial Positions (2)				17
Crude Oil Fair Value Position				288
Condensate Purchase Contracts				
Mont Belvieu Fixed Price	3,000 bbls/d	January – December 2016	US$39.20/bbl	(2)
Power Purchase Contracts				
Power Fair Value Position				(13)
Interest Rate Swaps				(2)

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

Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices or interest rates, with all other variables held constant. Management believes the price and interest rate fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices and interest rates on the Company's open risk management positions in place as at December 31, 2015 and 2014 could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

		2015		2014	
	Sensitivity Range	Increase	Decrease	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent and WTI Hedges	(243)	245	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	80	(80)	5	(5)
Condensate Commodity Price	± US$10 per bbl Applied to Condensate Hedges	23	(23)	-	-
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	-	-	(70)	70
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)	19	(19)
Interest Rate Swaps	± 50 Basis Points	38	(46)	-	-

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 7, 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 and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. As at December 31, 2015, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2014 – US$4,750 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2014 – US$nil). 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 foreign exchange (gain) loss as follows:

For the years ended December 31,	2015	2014	2013
$0.01 Increase in the U.S. to Canadian Dollar Exchange Rate	48	48	48
$0.01 Decrease in the U.S. to Canadian Dollar 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 the Company's exposure to interest rate volatility, the Company may periodically enter into interest rate swap contracts related to future debt issuances. As at December 31, 2015, the Company had a notional amount of US$300 million in forward swaps.

As at December 31, 2015, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2014 – $nil, 2013 – $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 loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of the credit policy approved by the Audit Committee of the Board of Directors governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with large commercial counterparties, most of which have investment grade credit ratings. 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. As at December 31, 2015 and 2014, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2015, 91 percent (2014 – 91 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. Cenovus's exposure to its counterparties is within credit policy tolerances.

As at December 31, 2015, Cenovus had one counterparty (2014 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. 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, 2015, Cenovus had $4.1 billion in cash and cash equivalents, and $4.0 billion available on its committed credit facility. In addition, Cenovus had in place a $1.5 billion Canadian base shelf prospectus and a US$2.0 billion U.S. base shelf prospectus, the availability of which are dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

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 (2)	-	3	1	4	**8**

2014	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,588	-	-	-	2,588
Risk Management Liabilities (1)	12	4	-	-	16
Long-Term Debt (2)	293	585	2,093	7,724	10,695
Other (2)	-	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,	2015	2014	2013
Interest Paid	**330**	335	409
Interest Received	**19**	33	119
Income Taxes Paid	**933**	46	133

34. COMMITMENTS AND CONTINGENCIES

A) Commitments

As part of normal operations, the Company has committed to certain amounts over the next five years and thereafter as follows:

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)	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 (2)	1,008	883	964	953	1,067	26,309	**31,184**
Fixed Price Product Sales	55	3	-	-	-	-	**58**

2014	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Transportation and Storage (1)	522	637	644	823	1,590	23,632	27,848
Operating Leases (Building Leases)	124	122	120	162	160	2,796	3,484
Product Purchases	101	7	-	-	-	-	108
Capital Commitments	90	55	11	2	-	46	204
Other Long-Term Commitments	58	24	21	15	13	116	247
Total Payments (2)	895	845	796	1,002	1,763	26,590	31,891
Fixed Price Product Sales	54	55	3	-	-	-	112

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts undertaken on behalf of the FCCL and WRB are reflected at Cenovus's 50 percent interest.

In 2015, net transportation commitments of $92 million were assumed upon the acquisition of the Company's crude-by-rail terminal.

As at December 31, 2015, there were outstanding letters of credit aggregating $64 million issued as security for performance under certain contracts (2014 – $74 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 it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

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 $2,052 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, 2015

(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, 2015 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 9, 2016 with an effective date of December 31, 2015.

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]
2014			
Beginning of year	1,455	251	795
Revisions and improved recovery	8	(2)	183
Extensions and discoveries	83	22	24
Purchase of reserves in place	-	-	2
Sale of reserves in place	-	(10)	(5)
Production	(43)	(25)	(179)
End of year	1,503	236	820
Developed	180	183	817
Undeveloped	1,323	53	3
Total	1,503	236	820
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**

(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)
2015	**50.28**	**46.78**	**59.41**	**2.58**	**2.69**
2014	95.55	84.27	97.60	4.34	4.63

(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)	2015	2014
Future cash inflows	**73,219**	122,882
Less future:		
Production costs	**34,339**	41,292
Development costs	**14,626**	15,643
Decommissioning liability payments	**3,706**	960
Income taxes	**4,432**	14,935
Future net cash flows	**16,116**	50,052
Less 10 percent annual discount for estimated timing of cash flows	**10,090**	31,065
Discounted future net cash flows	**6,026**	18,987

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2015	2014
Balance, beginning of year	**18,987**	13,992
Changes resulting from:		
Sales of oil and gas produced during the period	**(2,054)**	(3,947)
Extensions, discoveries and improved recovery, net of related costs	**535**	1,498
Purchases of proved reserves in place	**-**	4
Sales of proved reserves in place	**(87)**	(134)
Net change in prices and production costs	**(20,942)**	6,414
Revisions to quantity estimates	**1,021**	361
Accretion of discount	**2,441**	1,809
Previously estimated development costs incurred net of change in future development costs	**2,636**	279
Asset Retirement Obligation	**(313)**	(15)
Other	**(186)**	48
Net change in income taxes	**3,988**	(1,322)
Balance, end of year	**6,026**	18,987

OTHER FINANCIAL INFORMATION

Results of Operations

($ millions)	2015	2014
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	**2,829**	4,546
Intersegment sales	**335**	812
	3,164	5,358
Less:		
Operating costs, production and mineral taxes, and accretion of decommissioning liabilities[1]	**1,235**	1,512
Depreciation, depletion and amortization	**1,845**	1,707
Goodwill impairment	**-**	497
Exploration expense	**138**	86
Operating income	**(54)**	1,556
Income taxes	**(14)**	517
Results of operations	**(40)**	1,039

(1) Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense. As a result, for the year ended December 31, 2014, $17 million was reclassified.

Capitalized Costs

($ millions)	2015	2014
Proved oil and gas properties	**31,812**	32,030
Unproved oil and gas properties [2]	**1,575**	1,625
Total capital cost	**33,387**	33,655
Accumulated depreciation, depletion and amortization	**19,185**	17,386
Net capitalized costs	**14,202**	16,269

(2) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($ millions)	2015	2014
Acquisitions		
Unproved	**4**	16
Proved	**-**	2
Total acquisitions	**4**	18
Exploration costs	**66**	159
Development costs	**1,360**	2,623
Total costs incurred	**1,430**	2,800

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, 2015, 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, 2015, 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, 2015, 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, 2015, 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, 2015.

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, 2015, 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, 2015, filed as part of this annual report on Form 40-F. 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, 2015, 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, Valerie A.A. Nielsen 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 11, 2016

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 11, 2016

/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 11, 2016

/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, 2015, 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 11, 2016

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, 2015, 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 11, 2016

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, 2015 of Cenovus Energy Inc. of our report dated February 10, 2016, relating to the Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2015 and December 31, 2014 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, 2015 and the related notes and to the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as at December 31, 2015, 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. 333-196696) of Cenovus Energy Inc. of our report dated February 10, 2016 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 11, 2016

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, 2015, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2015, 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, 2015 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. 333-196696), 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 11, 2016

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, 2015, 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, 2015 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. 333-196696), 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 11, 2016

Cenovus Energy Inc.

Statement of Contingent and Prospective Resources

For the Year Ended December 31, 2015

February 10, 2016

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, 2015.

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 fundamental data in 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 at the Greater Pelican 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, 2016 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, 2015).

BITUMEN BEST ESTIMATE ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES

Company Interest (billions of barrels)	December 31, 2015		December 31, 2014 (1)
Economic Contingent Resources (2)	**Before Royalties**	**After Royalties**	
By Project Maturity Subclass:			
Development pending			
Christina Lake	**0.8**	**0.6**	
Foster Creek	**1.1**	**0.9**	
Borealis	**2.6**	**2.2**	
Pelican Lake	**1.7**	**1.5**	
Total	**6.2**	**5.2**	
Development unclarified			
Borealis	**3.1**	**2.6**	
Total Economic Contingent Resources	**9.3**	**7.8**	9.3
Prospective Resources (3)			
By Project Maturity Subclass:			
Prospect			
Best Estimate	**7.4**	**N/A**	7.5

(1) Subclasses and after royalty volumes for contingent resources were not disclosed for year-end 2014.
(2) There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.
(3) 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.

Bitumen best estimate economic contingent resources are virtually unchanged from year-end 2014. Bitumen best estimate prospective resources are one percent lower than in 2014.

EVALUATION BASIS

The evaluation assumes that the majority of Cenovus's bitumen resources will be recovered and produced using established steam assisted gravity drainage ("SAGD") technology, with only a minor portion of the Company's resources likely to be developed using cyclic steam stimulation ("CSS"), also an established technology. 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 in the Grosmont carbonate formation for which the Company has extensive mineral rights. 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. Contingent resources in the carbonates are not included in the totals above.

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 ("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. 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.

- **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. 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. Stratigraphic test well drilling and seismic activity are continuing in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

  In the Greater Pelican Region, Cenovus received regulatory approval for a development project at the Grand Rapids property. Pilot project work was underway to validate technical assumptions and examine optimal development strategies however, as of February 2016 further activity in respect of the pilot project has been deferred in response to the current low commodity price environment. Further reclassification of contingent resources to reserves in the Greater Pelican 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 areas 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 the Telephone Lake property in the Borealis Region and the Grand Rapids formation in the Greater Pelican Region. These 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 unclarified.

    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 regional areas: Christina Lake, Foster Creek, Borealis, and Greater Pelican. Within these areas are multiple projects at various levels of advancement. The contingent resources at Christina Lake and Foster Creek 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.

At Borealis 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.

At Pelican Lake, 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
Christina Lake	Development pending	Development/ Pre-development	230 - 870	2022 - 2048	SAGD
Foster Creek	Development pending	Development/ Pre-development	80 – 1,330	2024 - 2034	SAGD/CSS
Borealis	Development pending Development unclarified	Development - Telephone Lake Conceptual – All remaining projects	900 – 2,800	2020 - 2028	SAGD
Pelican Lake	Development pending	Pre-development	2,830	2022	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 build and 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 not subject to technology under development, and which are economically viable.

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 2015 as low commodity prices limited availability of delineation capital. For example, most stratigraphic wells drilled in 2015 were focused on supporting conversion of reserves to production at Christina Lake and Foster Creek, resulting in negligible prospective and contingent resources reclassification. Consequently, bitumen best estimate economic contingent resources for 2015 remained virtually unchanged at 9.3 billion barrels.

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 Contingent Resources [(1)]**	**Best Estimate Prospective Resources [(2)]**
As at December 31, 2014	3.300	9.3	7.5
Transfers between Categories			
Additions from Other Resources Categories	-	-	-
Reductions to Other Resources Categories	-	-	-
Additions and Revisions Net of Transfers	0.049	0.0	(0.1)
Net Acquisitions and Divestitures	-	-	-
Production	(0.051)	-	-
As at December 31, 2015	3.298	9.3	7.4

(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.