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, 2014 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:

757,103,201

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. 333-166419), 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, 2014.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2014.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2014.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2014.

Annual Information Form

For the year ended December 31, 2014

February 12, 2015

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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 Company" 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 Company's experience and perception of historical trends. This forward-looking information is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "future", "target", "project", "capacity", "could", "should", "focus", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about Cenovus's strategy and related milestones and schedules, projected future value or net asset value, projections for 2015 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 contingent and prospective resources estimates, broadening market access, improving cost structures, dividend plans and strategy, including with respect to the dividend reinvestment plan, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as the Company'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 Company'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 Company 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 Company's risk management program, including the impact of derivative financial instruments, the success of Cenovus's hedging strategies and the sufficiency of the Company's liquidity position; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in Cenovus's marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted earnings before interest, taxes, depreciation and amortization as well as debt to capitalization; the Company's ability to access various sources of debt and equity capital, generally, and on terms acceptable to the Company; 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 estimates; the Company'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 heavy oil business; reliability of the Company's assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; 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 Company's ability to secure adequate product transportation including sufficient crude-by-rail or alternate transportation to address any gaps caused by operational constraints in the pipeline system; 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 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 Company 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 Company'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 www.sedar.com, www.sec.gov and on the Company's website at cenovus.com.

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.

The Company'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, 2014 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 Company's remaining subsidiaries and partnerships each account for (i) less than 10 percent of the Company's consolidated assets as at December 31, 2014 and (ii) less than 10 percent of the Company's consolidated revenues for the year ended December 31, 2014. In aggregate, Cenovus's unidentified subsidiaries and partnerships did not exceed 20 percent of the Company's total consolidated assets or total consolidated revenues as at and for the year ended December 31, 2014.

GENERAL DEVELOPMENT OF CENOVUS'S BUSINESS

Cenovus is a Canadian integrated oil company headquartered in Calgary, Alberta. The Company began independent operations on December 1, 2009 following the split of Encana into two independent publicly traded energy companies. Cenovus is in the business of developing, producing and marketing crude oil, NGLs and natural gas in Canada with refining operations in the United States.

Cenovus's Strategy

Cenovus's strategy is to create long-term value through the development of its vast oil sands resources, execution excellence, ability to innovate and financial strength. The Company is focused on continually building net asset value and paying a sustainable dividend. Inherent to this strategy is a focus on protecting the Company's financial resilience by evaluating on a regular basis its capital investment plans, dividend plans and other relevant factors.

Cenovus's integrated approach, which enables the Company to capture the full value chain from production to high-quality end products like transportation fuels, relies on its entire asset mix:

- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of revenue streams;
- Natural gas for the fuel used at the Company's oil sands and refining facilities and for the cash flow it provides to help fund capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

Substantial Oil Sands Portfolio

Cenovus is focused on development of its two producing steam assisted gravity drainage ("SAGD") projects, Foster Creek and Christina Lake. Foster Creek and Christina Lake have a combined production capacity of 288,000 gross barrels per day with future plans to increase combined production capacity to 620,000 gross barrels per day.

Cenovus's future opportunities are currently based on the development of the land positions held in the oil sands in northern Alberta, including Narrows Lake, Grand Rapids and Telephone Lake. Cenovus is a 50 percent partner in the Narrows Lake oil sands project and owns 100 percent of the Grand Rapids and Telephone Lake oil sands projects. Cenovus's normal development planning is to evaluate these resources through stratigraphic test well drilling programs.

In total, Cenovus has regulatory approval for production capacity of 955,000 gross barrels per day from its oil sands assets, including current production, with an additional 50,000 gross barrels per day in the approval process.

Established Conventional Assets

Cenovus's conventional operations consist of crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, heavy oil development at Pelican Lake and tight oil assets in Alberta. Cenovus's conventional oil and natural gas production provides predictable cash flows that help fund future growth opportunities in the oil sands. In addition, the Company's natural gas production acts as an economic hedge for its natural gas fuel consumption at both its upstream and refining operations.

Cenovus owns mineral rights on approximately 70 percent or 4.5 million acres of its conventional lands (fee lands). Production from fee lands accounts for approximately 50 percent of Cenovus's total conventional production. Fee land production, where Cenovus maintains a working interest, is subject to mineral tax, which is generally lower than the royalties paid to governments or other mineral interest owners. In addition, a portion of the fee lands are leased to third parties which may give rise to royalty income.

Strong Project Execution & Innovation

Cenovus applies a manufacturing-like phased approach in developing its oil sands projects. This approach incorporates learnings from previous phases into future growth plans allowing the Company to minimize costs. In addition, by focusing on innovation, Cenovus continually looks for opportunities to improve both its economic and environmental performance.

Market Access

Accessing higher value markets and ensuring future market access for products is a key focus area for Cenovus. The Company's continued support for proposed new pipeline projects will allow Cenovus to access new markets in the U.S. and globally. In addition, expanding rail capacity will offer an important near and mid-term transportation alternative. Shipping by rail will ease pipeline congestion and pricing pressure, while providing access to niche markets that have the potential to offer premium pricing.

Cenovus is also assessing options to maximize the value of its oil by offering a wider range of products, including existing dilbit blends, under blended bitumen or dry bitumen.

Financial Strength

Cenovus has strong producing assets, an integrated portfolio and a solid balance sheet all of which have positioned it well to face the challenges of a lower commodity price environment. The Company's disciplined approach to capital allocation and focus on cost reduction will help support capital investment and a sustainable dividend. Cenovus's capital planning process is flexible and spending can be reduced in response to commodity prices and other economic factors, which will allow the Company to maintain its financial strength while continuing to advance its strategy.

In response to the current low crude oil price environment, Cenovus's total annual 2015 capital investment has been significantly reduced from 2014 levels. The Company will continue to assess its spending plans on a regular basis while closely monitoring crude oil prices. Cenovus expects 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 satisfy the Company's cash requirements.

Environmental Stewardship

Cenovus lives up to its responsibility as a developer of one of Canada's most valuable resources. Like any company, Cenovus has environmental challenges including minimizing the physical impacts to the lands, lakes and streams surrounding its operations, reducing the greenhouse gas ("GHG"), intensity from production, minimizing the amount of land needed to build each oil sands project and preventing impacts on wildlife in the areas Cenovus operates. Cenovus strives to integrate environmental considerations into its business model.

Safety

Safety is a key part of Cenovus's culture and the Company is committed to developing its resources safely and responsibly. In addition to the Company's responsibility to create a safe workplace, Cenovus provides employees, suppliers, contractors and consultants the information, training and tools required to take responsibility for their own safety and that of their co-workers.

CENOVUS'S BUSINESS

The Company's reportable segments are as follows:

- **Oil Sands,** which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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. This segment also includes the CO_2 enhanced oil recovery ("EOR") 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. 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.

THREE YEAR HISTORY

The following describes significant events of the last three fiscal years:

2012

- **Christina Lake phase H update.** In the second quarter, the expected gross production capacity for Christina Lake phase H was increased from 40,000 barrels per day to 50,000 barrels per day due to the addition of a fifth steam generator that incorporates blowdown boiler technology. This is expected to enhance efficiency by increasing steam capacity and the water recycle rate, leading to fuel savings and a reduction in water use. Cenovus commercialized blowdown boiler technology in 2011 after testing it at Foster Creek.
- **Regulatory and partner approval at Narrows Lake.** In the second quarter, Cenovus received regulatory approval for the Narrows Lake project, which includes the use of both traditional SAGD and SAGD with the SAP enhancement. In the fourth quarter, phase A, which has planned gross production capacity of 45,000 barrels per day, received partner approval. The Narrows Lake project is currently expected to have gross production capacity of 130,000 barrels per day when all three phases are complete.
- **First production at Christina Lake phase D.** In the third quarter, phase D of Christina Lake achieved first production, approximately three months ahead of schedule. Total gross production for phases A through D at Christina Lake averaged almost 64,000 barrels per day in 2012.
- **Grand Rapids pilot update.** In the third quarter, steam injection commenced on the second pilot well pair at Grand Rapids, with initial production achieved in the first quarter of 2013.
- **Senior unsecured notes issued.** In the third quarter, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$500 million, with a coupon rate of 3.00 percent, due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042, for an aggregate amount of US$1.25 billion.
- **Christina Lake regulatory approval.** In the fourth quarter, Cenovus received regulatory approval to add cogeneration facilities at Christina Lake and increase expected total gross production capacity by 10,000 barrels per day at each of phase F and G.
- **Telephone Lake dewatering pilot.** In the fourth quarter, with the drilling and facility construction completed, operation of the Telephone Lake dewatering pilot commenced.

2013

- **Christina Lake 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 expected gross production capacity of 50,000 barrels per day from each phase.
- **Production from Grand Rapids pilot.** In the first quarter, Cenovus achieved first production from the second pilot well pair at Grand Rapids. The Company operated the pilot project at Grand Rapids throughout the year. The purpose of the pilot was to test reservoir performance.
- **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. This program is expected to add up to 22,000 barrels per day of gross production capacity to the Christina Lake facility.
- **Construction at Narrows Lake phase A initiated.** In the third quarter, construction of the Narrows Lake phase A plant was initiated. Site construction, engineering and procurement at Narrows Lake are progressing as expected. Phase A has 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 Company's US$800 million senior unsecured notes due September 2014.
- **Divesture 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 top water.
- **Receipt of Partnership contribution receivable.** In the fourth quarter, Cenovus received US$1.4 billion from ConocoPhillips, the Company's partner in FCCL, representing the remaining principal and interest due under the Partnership Contribution Receivable through the Company's interest in FCCL, net to Cenovus.
- **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. Phases F, G and H are each expected to ramp-up to 30,000 barrels per day. Once these phases are complete, optimization work to lower steam to oil ratios, increase production and improve plant efficiency is expected to commence. Total projected gross production capacity from these three phases, including optimization, remains unchanged at up to 125,000 barrels per day.

2014

- **Regulatory approval received for Grand Rapids.** In the first quarter, Cenovus received regulatory approval for its 100 percent owned Grand Rapids project. The project, which is located within the Greater Pelican Region, is expected to have production capacity 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.
- **Divesture 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 expected 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, which is located within the Company's Borealis Region of northern Alberta, is expected to have production capacity in excess of 300,000 barrels per day.

NARRATIVE DESCRIPTION OF CENOVUS'S BUSINESS

The following map outlines the location of Cenovus's upstream and refining assets as at December 31, 2014:

(1) The Pelican Lake heavy oil operations located within the Greater Pelican Region form part of Cenovus's Conventional Oil and Gas operations.

This graphic is for illustration purposes only. Land as at December 31, 2014.

OVERVIEW

All of Cenovus's reserves and production are located in Canada, primarily within the provinces of Alberta and Saskatchewan. As at December 31, 2014, Cenovus had a land base of approximately 6.7 million net acres. The estimated proved reserves life index based on working interest production as at December 31, 2014 was approximately 23 years.

OIL SANDS

Oil Sands includes Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development such as Grand Rapids and Telephone Lake. The Company's Athabasca natural gas assets also form part of this segment. 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 and managing partner of FCCL, and owns 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.

As at December 31, 2014, Cenovus held bitumen rights of approximately 1.5 million gross acres (1.1 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.

Landholdings

The following table summarizes Cenovus's landholdings as at December 31, 2014:

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Foster Creek	16	8	135	67	151	75	50%
Christina Lake	8	4	49	25	57	29	50%
Narrows Lake	-	-	27	13	27	13	50%
Grand Rapids (1)	-	-	61	61	61	61	100%
Telephone Lake	16	16	142	142	158	158	100%
Athabasca	417	345	454	380	871	725	83%
Other	28	10	1,052	773	1,080	783	72%
Total	485	383	1,920	1,461	2,405	1,844	77%

(1) Overlapping landholdings between Grand Rapids 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 for the periods indicated:

	Crude Oil and NGLs (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
(annual average)	**2014**	2013	**2014**	2013	**2014**	2013
Foster Creek	**59,172**	53,190	**-**	-	**59,172**	53,190
Christina Lake	**69,023**	49,310	**-**	-	**69,023**	49,310
Athabasca (1)	**-**	-	**22**	21	**3,667**	3,500
Total	**128,195**	102,500	**22**	21	**131,862**	106,000

(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, 2014. These figures exclude wells which were capable of producing, but that were not producing as at December 31, 2014:

	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Foster Creek	283	142	-	-	283	142
Christina Lake	119	60	-	-	119	60
Grand Rapids	2	2	-	-	2	2
Athabasca	-	-	286	274	286	274
Other	3	3	-	-	3	3
Total	407	207	286	274	693	481

Foster Creek

Cenovus has a 50 percent working interest in Foster Creek, Cenovus's first commercial 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 Company 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 Company's behalf and/or its assignee's behalf.

Production from phases A through F at Foster Creek averaged 59,172 barrels per day in 2014. Phase F achieved first production in September 2014 with full ramp up expected to take approximately 18 months. Expansion work is underway at phase G, and is expected to add additional production capacity of 30,000 gross barrels per day. Expansion work on phase H, with initial design capacity of 30,000 gross barrels per day, has been deferred in response to the current economic environment. Spending will be deferred until crude oil prices recover.

In December 2014, Cenovus received regulatory approval from the Alberta Energy Regulator ("AER") for Foster Creek phase J with expected gross production capacity of 50,000 barrels per day. Total gross production capacity for phases A through J, including optimization work, is expected to reach 310,000 barrels per day.

Cenovus has successfully piloted and implemented its Wedge Well™ technology at Foster Creek whereby an additional well is drilled between two producing well pairs to produce bitumen that is heated by proximity to a steam chamber, but is not recoverable by the adjacent production wells. This technology requires minimal additional steam, thus it helps reduce the overall steam to oil ratio. In 2014, 22 wells using the Company's Wedge Well™ technology were drilled (2013 – 30 wells) at Foster Creek. As at December 31, 2014 there were 89 gross producing wells of this type.

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 uses SAGD technology and produces from the McMurray formation.

Production from phases A through E at Christina Lake averaged 69,023 barrels per day in 2014. An optimization program for phases C, D and E is expected to add up to 22,000 gross barrels per day of production capacity in late 2015. Expansion work is underway at phase F (including cogeneration), with production capacity of 50,000 gross barrels per day expected in the second half of 2016. Expansion work on phase G, with initial design capacity of 50,000 gross barrels per day, has been deferred in response to the current economic environment. Spending on phase G will be deferred until crude oil prices recover.

Cenovus expects to receive regulatory approval for phase H in the first half of 2015, a 50,000 gross barrel per day phase. With the addition of phases F, G and H, Cenovus believes Christina Lake has potential gross production capacity of 288,000 gross barrels per day, increasing to as much as 310,000 gross barrels per day with optimization.

In 2014, Cenovus drilled 24 gross wells (2013 – 11 wells) at Christina Lake using the Company's Wedge Well™ technology and as at December 31, 2014 there were 19 gross wells of this type producing.

Several innovations to SAGD technology have been undertaken at Christina Lake over the past several years. One major innovation is SAP technology that is currently being piloted at Christina Lake. 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. Based on results from the SAP pilot, 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 barrel a 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 until crude oil prices recover. Cenovus has recently integrated Narrows Lake under the same management team as its nearby Christina Lake project. The future development of Narrows Lake will benefit from the existing infrastructure and resources at Christina Lake, which is expected to lower overall costs.

Telephone Lake

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

In November 2014, Cenovus received regulatory approval from the AER for a SAGD project at Telephone Lake with initial production capacity of 90,000 barrels per day. Telephone Lake is estimated to have a 40-year reserve life with total production capacity in excess of 300,000 barrels per day and is expected to be developed in multiple phases.

Telephone Lake is a unique oil sands project because there is a layer of groundwater directly above the oil that's 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.

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 Company's Pelican Lake heavy oil operations and existing facilities.

In December 2010, the Company drilled its first pilot SAGD well pair in the Cretaceous Grand Rapids formation. A second well pair was drilled in early 2012 and a third well pair is planned for the first quarter of 2015. Data from these well pairs will help determine the future pace of development at Grand Rapids.

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. Grand Rapids is estimated to have a 40-year reserve life and is expected to be developed in multiple phases.

Other Emerging Assets

Cenovus has a number of other emerging assets, including the Steepbank and East McMurray properties which are located in the Borealis Region, southwest of Telephone Lake. In 2014, 21 gross stratigraphic wells were drilled. Data from the stratigraphic wells will determine future development timing.

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 new 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. In the second and third quarters of 2014, this rig was used to drill 14 stratigraphic wells. The Company completed construction on a second SkyStrat™ drilling rig in the fourth quarter of 2014.

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 Company'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 2009 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 Company's annualized natural gas production of approximately 15 million cubic feet per day in 2014 (2013 – 16 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 2014, the Company's Oil Sands capital investment was $2.0 billion, primarily related to the expansion at Foster Creek and Christina Lake. The production capacity for these projects is expected to increase to approximately 288,000 gross barrels per day with completion of Foster Creek phase F. Ramp up to total production for phase F is expected to take approximately 18 months from September 2014.

- Capital at Foster Creek was focused on expansion of phases F, G and H, offsite facility work related to phases G and H, drilling of sustaining wells, and operational improvement projects.
- Capital at Christina Lake was focused on expansion of phases F and G, optimization of phases C, D, and E, phase E well pad and offsite facility construction, and sustaining well programs including the use of the Company's Wedge Well™ technology.

- Capital at Narrows Lake was focused on phase A engineering, procurement, and plant construction.
- Capital at Telephone Lake was focused on the preliminary engineering work on the central processing facility, costs related to the dewatering pilot project and the drilling of stratigraphic test wells.
- Capital at Grand Rapids was focused on costs related to the pilot project, the drilling of stratigraphic test wells and the dismantling and relocation of an existing SAGD facility to Grand Rapids.

Due to the lower crude oil price environment, 2015 capital spending will be focused on the continued expansion of Foster Creek phase G and Christina Lake phase F (including cogeneration) as well as optimization of phases C, D and E at Christina Lake. Funding will also be allocated 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 from conventional crude oil, NGLs and natural gas assets in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the CO_2 enhanced oil recovery project at Weyburn, and emerging tight oil assets in Alberta. The established assets in this segment are strategically important due to their long life reserves, stable operations, diversity of crude oil produced and free cash flow generation.

At December 31, 2014, Cenovus had an established land position of approximately 5.1 million gross acres (4.9 million net acres), of which approximately 3.3 million gross acres (3.2 million net acres) are developed. Cenovus owns the mineral rights on approximately 70 percent or 4.5 million net acres of the Company's conventional lands (fee lands), of which 2.5 million acres are developed. Production from fee lands comprises approximately 50 percent of the Company's total conventional production. Fee lands where Cenovus has maintained a working interest are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, Cenovus leases over 2.0 million acres to third parties, which may result in royalty income. In 2014, Cenovus had approximately 7,600 barrels of oil equivalent per day of royalty interest production from fee lands. Cenovus leases crown lands in Alberta, mainly in the Early Cretaceous geological formations, primarily in the Suffield area and in Saskatchewan.

Landholdings

	Developed Acreage [2]		Undeveloped Acreage [2]		Total Acreage [1]		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Alberta							
Grassland [3]	976	961	49	47	1,025	1,008	98%
Suffield	935	924	125	121	1,060	1,045	99%
Langevin [4]	742	702	235	217	977	919	94%
Pelican Lake [5]	126	125	224	210	350	335	96%
Wainwright	343	322	190	186	533	508	95%
Other	38	13	164	138	202	151	75%
Saskatchewan							
Weyburn	116	103	327	314	443	417	94%
Bakken	14	13	183	182	197	195	99%
Other	7	3	19	19	26	22	86%
Manitoba	5	5	252	252	257	257	100%
Total	3,302	3,171	1,768	1,686	5,070	4,857	96%

(1) Includes 2.1 million gross acres of fee land where Cenovus has a working interest, and 1.1 million gross acres of fee land partially leased to third parties. Excludes 1.3 million gross acres of fee land fully leased to third parties.
(2) Developed acreage includes 2.1 million gross acres of fee land and undeveloped acreage includes 1.1 million gross acres of fee land.
(3) Grassland is located in the Drumheller and Brooks areas.
(4) Langevin is located north west of Medicine Hat.
(5) Overlapping landholdings between Grand Rapids and Pelican Lake have been allocated to Grand Rapids based on the project's approved development area.

Production

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

(annual average)	Crude Oil and NGLs (bbls/d) 2014	2013	Natural Gas (MMcf/d) 2014	2013	Total Production [1] (BOE/d) 2014	2013
Alberta						
Grassland [2]	**8,923**	7,720	**232**	252	**47,590**	49,720
Suffield	**10,010**	11,391	**135**	149	**32,510**	36,224
Langevin [3]	**9,368**	8,754	**96**	101	**25,368**	25,587
Pelican Lake	**24,924**	24,254	**-**	-	**24,924**	24,254
Wainwright [4]	**4,687**	4,668	**2**	3	**5,020**	5,168
Other	**8**	9	**-**	2	**8**	342
Saskatchewan						
Weyburn	**16,196**	16,361	**-**	-	**16,196**	16,361
Shaunavon [5]	**-**	2,101	**-**	-	**-**	2,101
Bakken [4]	**1,182**	1,508	**1**	1	**1,349**	1,676
Other	**-**	9	**-**	-	**-**	9
Total	**75,298**	76,775	**466**	508	**152,965**	161,442

(1) Includes production from fee lands in which Cenovus has a working interest and fee lands in which Cenovus has retained a royalty interest.
(2) Grassland is located in the Drumheller and Brooks areas.
(3) Langevin is located north west 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 fee lands in these areas.
(5) In the third quarter of 2013, Cenovus sold its Lower Shaunavon tight oil asset in southern Saskatchewan.

Producing Wells

The following table summarizes Cenovus's Conventional interests in producing wells as at December 31, 2014. These figures exclude wells which were capable of producing, but that were not producing, as at December 31, 2014:

	Producing Oil Wells Gross	Net	Producing Gas Wells Gross	Net	Total Producing Wells [1] Gross	Net
Alberta						
Grassland [2]	410	403	8,832	8,683	9,242	9,086
Suffield	780	780	10,686	10,668	11,466	11,448
Langevin [3]	276	273	4,792	4,780	5,068	5,053
Pelican Lake	612	612	4	4	616	616
Wainwright	80	71	12	3	92	74
Other	11	5	2	1	13	6
Saskatchewan						
Weyburn	656	414	-	-	656	414
Bakken	10	3	-	-	10	3
Other	1	1	-	-	1	1
Total	2,836	2,562	24,328	24,139	27,164	26,701

(1) Includes wells on fee lands where Cenovus has a working interest. Excludes wells on fee lands where Cenovus only has a royalty interest.
(2) Grassland is located in the Drumheller and Brooks areas.
(3) Langevin is located north west 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 Company's oil assets including water flooding, CO_2 miscible flooding and alkali surfactant polymer flooding.

Cenovus operates the world's largest CO_2 miscible flood project. The Weyburn unit produces light to medium sour crude oil from the Mississippian Midale formation and covers 78 sections of land in southeastern Saskatchewan. As at December 31, 2014, approximately 64 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 24 million tonnes of CO_2 have been injected under the program. 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 Saskatchewan. In the unitized portion of the Weyburn field in southwestern Saskatchewan, Cenovus has a 62 percent working interest. However, after taking into consideration a net royalty interest obligation to a third party, Cenovus's economic interest is 50 percent. Cenovus operates on behalf of the unit and owns 62 percent of the CO_2 pipeline from the Boundary Dam to Weyburn.

Using a patterned, horizontal well polymer flood, Cenovus produces heavy crude oil from the Cretaceous Wabiskaw formation at its Pelican Lake property, within the Greater Pelican Region in northeastern Alberta. Cenovus holds a 38 percent non operated interest in a 110 kilometre, 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 for the periods indicated:

	Net Wells Drilled [1]		Average Production [2] (bbls/d) Light / Medium		Heavy	
	2014	2013	**2014**	2013	**2014**	2013
Alberta						
Grassland [3]	**42**	44	**8,224**	7,004	**-**	-
Suffield	**18**	24	**-**	-	**9,991**	11,375
Langevin [4]	**29**	36	**9,221**	8,625	**-**	-
Wainwright [5]	**4**	39	**42**	40	**4,631**	4,616
Pelican Lake	**25**	49	**-**	-	**24,924**	24,254
Other	**1**	6	**8**	8	**-**	-
Saskatchewan						
Weyburn	**7**	14	**15,921**	16,229	**-**	-
Shaunavon [6]	**-**	-	**-**	2,101	**-**	-
Bakken [5]	**-**	-	**1,115**	1,451	**-**	-
Other	**-**	-	**-**	9	**-**	-
Total	**126**	212	**34,531**	35,467	**39,546**	40,245

(1) *Excludes wells drilled by third parties on fee land.*
(2) *Includes production from fee lands in which Cenovus has a working interest and fee lands in which Cenovus has retained a royalty interest.*
(3) *Grassland landholdings are located in the Drumheller and Brooks areas.*
(4) *Langevin landholdings are located north west 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 fee lands in these areas.*
(6) *In the third quarter of 2013, Cenovus sold its Lower Shaunavon tight oil asset in southern Saskatchewan.*

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 Company'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 Company'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 2014, Conventional gas production averaged 466 MMcf per day (2013 – 508 MMcf per day). Cenovus did not drill any gas wells in 2014 or 2013.

Capital Investment

In 2014, the Company's Conventional capital investment was $840 million, primarily related to tight oil development, facilities work and expansion of the polymer flood at Pelican Lake. 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. This segment coordinates Cenovus's marketing and transportation initiatives to optimize the value of its products.

Refining

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. In 2015, the Company's refineries have a combined stated processing capacity of approximately 460,000 gross barrels per day of crude oil (2014 – 460,000 gross bbls/d), including heavy crude oil processing capability of up to 255,000 gross barrels per day.

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

Refinery Operations [1]	2014	2013
Crude Oil Capacity (Mbbls/d)	**460**	457
Crude Oil Runs (Mbbls/d)	**423**	442
Heavy Oil	**199**	222
Light/Medium	**224**	220
Crude Utilization (%)	**92**	97
Refined Products (Mbbls/d)		
Gasoline	**231**	232
Distillates	**137**	144
Other	**77**	87
Total	**445**	463

(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 150 U.S. refineries 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.

Throughout 2014, the Wood River Refinery's stated crude oil processing capacity 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 ("CORE") project, the Wood River Refinery increased its total Canadian heavy crude oil processing capacity up to 220,000 gross barrels per day. In 2014, 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 ("TAN") crudes.

Borger Refinery

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

The Borger Refinery's stated crude 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 a capacity of 45,000 gross barrels per day. The stated processing capacity is unchanged for 2015.

Marketing

Cenovus's Marketing group is focused on enhancing the netback price of the Company's production. As part of these activities, the group carries out 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 also seeks to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced products. Details of these transactions are found in the notes to the Company's audited Consolidated Financial Statements for the year ended December 31, 2014.

Crude Oil Marketing

Cenovus's Crude Oil Marketing group manages the marketing of crude oil for the Company's upstream operations. Their objective is to sell production to achieve the best price within the constraints of a diverse sales portfolio, as well as to obtain and manage condensate supply, inventory and storage to meet diluent requirements.

Natural Gas Marketing

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.

Transportation

Cenovus's Transportation group is committed to accessing higher value markets and ensuring future market access. Cenovus actively supports a variety of new pipeline projects that will facilitate access to new markets in the U.S. and overseas. As at December 31, 2014, Cenovus has entered into various firm transportation commitments totaling $28 billion, most of which relate to pipelines that are subject to regulatory approval. The Company's portfolio of transportation commitments includes feeder pipelines from its production areas to the Edmonton and Hardisty 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 fourth quarter of 2014, Cenovus increased its takeaway rail capacity to 30,000 barrels per day. The Company's longer term target is to commit to transportation solutions for up to 50 percent of marketable production, including growing rail capacity to between 10 and 20 percent of marketable production.

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 Company's reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

The Company's reserves are primarily located in Alberta and Saskatchewan, Canada. Cenovus retained two independent qualified reserves evaluators ("IQREs"), McDaniel and 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, NGLs, natural gas, and coal bed methane ("CBM") reserves. McDaniel evaluated approximately 96 percent of Cenovus's total proved reserves, located throughout Alberta, and GLJ evaluated approximately four percent of the Company's total proved reserves, located throughout Saskatchewan and Manitoba. Cenovus also engaged McDaniel to evaluate 100 percent of the Company's bitumen contingent and prospective resources.

The Reserves Committee of Cenovus's Board of Directors ("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 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 and resources data and the report of the IQREs and provides a recommendation regarding approval of the reserves and resources disclosure to the Board.

The majority of 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 bitumen, oil and natural gas 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 11, 2015, with an effective date of December 31, 2014. McDaniel's preparation date of the information is January 12, 2015, and GLJ's preparation date is January 9, 2015.

DISCLOSURE OF RESERVES DATA

The reserves data presented summarizes the Company's bitumen, heavy oil, light and medium oil plus NGLs, and natural gas plus CBM reserves and the net present values of future net revenue for these reserves. The reserves data uses forecast prices and costs prior to provision for interest, general and administrative expenses, costs associated with environmental regulations, the impact of any hedging activities or the liability associated with certain abandonment and all well, pipeline and facilities reclamation costs. Future net revenues have been presented on a before and after income tax basis.

Cenovus holds significant fee title rights which generate production for the Company's account from third parties leasing those lands ("Royalty Interest Production"). As at December 31, 2014, approximately 2.4 million acres throughout southeastern Alberta and southern Saskatchewan and Manitoba were leased out to third parties. In accordance with NI 51-101, only the After Royalties volumes presented herein include reserves associated with this Royalty Interest Production ("Royalty Interest Reserves").

Summary of Company Interest Oil and Gas Reserves as at December 31, 2014
(Forecast Prices and Costs)

Before Royalties [1]	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	197	114	94	778
Developed Non-Producing	41	2	4	14
Undeveloped	1,732	40	22	4
Total Proved Reserves	1,970	156	120	796
Probable Reserves	1,330	123	46	260
Total Proved plus Probable Reserves	3,300	279	166	1,056

After Royalties [2]	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	159	97	84	793
Developed Non-Producing	31	1	3	14
Undeveloped	1,306	36	18	4
Total Proved Reserves	1,496	134	105	811
Probable Reserves	1,005	97	40	252
Total Proved plus Probable Reserves	2,501	231	145	1,063

Royalty Interest	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	-	1	6	40
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved Reserves	-	1	6	40
Probable Reserves	-	1	2	12
Total Proved plus Probable Reserves	-	2	8	52

(1) *Does not include Royalty Interest Reserves.*
(2) *Includes Royalty Interest Reserves.*

Summary of Net Present Value of Future Net Revenue as at December 31, 2014

(Forecast Prices and Costs)

Before Income Taxes	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%	Unit Value Discounted at 10 % (1) $/BOE
Proved Reserves						
Developed Producing	13,715	10,972	9,135	7,845	6,894	19.31
Developed Non-Producing	1,471	1,096	848	678	556	22.33
Undeveloped	58,310	25,769	13,177	7,456	4,504	9.69
Total Proved Reserves	73,496	37,837	23,160	15,979	11,954	12.38
Probable Reserves	58,033	19,036	8,364	4,571	2,854	7.07
Total Proved plus Probable Reserves	131,529	56,873	31,524	20,550	14,808	10.32

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

After Income Taxes (1)	Discounted at % / year ($ millions) 0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	10,984	8,815	7,347	6,313	5,549
Developed Non-Producing	1,088	822	642	518	428
Undeveloped	44,659	19,422	9,819	5,501	3,290
Total Proved Reserves	56,731	29,059	17,808	12,332	9,267
Probable Reserves	43,148	14,157	6,185	3,349	2,071
Total Proved plus Probable Reserves	99,879	43,216	23,993	15,681	11,338

(1) *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 Company's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2014.*

Total Future Net Revenue (undiscounted) as at December 31, 2014

(Forecast Prices and Costs) ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs (1)	Future Net Revenue Before Future Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved Reserves	193,934	44,022	54,957	20,084	1,376	73,496	16,765	56,731
Proved plus Probable Reserves	349,344	81,047	96,545	38,476	1,747	131,529	31,650	99,879

(1) *The abandonment costs only include downhole abandonment costs for the wells considered in the IQREs' evaluation of reserves. Abandonment of other wells, surface reclamation, asset recovery and facility site reclamation costs are not included.*

Future Net Revenue by Production Group as at December 31, 2014

(Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value (Company Interest After Royalties Reserves) ($/BOE)
Proved Reserves	Bitumen	17,745	11.86
	Heavy Oil	1,789	13.30
	Light & Medium Oil and NGLs	2,486	23.63
	Natural Gas	1,140	8.43
	Total	23,160	12.38
Proved plus Probable Reserves	Bitumen	23,560	9.42
	Heavy Oil	3,044	13.15
	Light & Medium Oil and NGLs	3,356	23.11
	Natural Gas	1,564	8.83
	Total	31,524	10.32

Additional Notes to Reserves Data Tables

- The estimates of future net revenue presented do not represent fair market value.
- Future net revenue 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 due to rounding.

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 area of properties in which the Company 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 Company's interest in a property, the total area 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.
7. **Royalty Interest Reserves** means those reserves related to Cenovus's royalty entitlement on lands to which the Company holds fee title and which have been leased to third parties, plus any reserves related to other royalty interests, such as overriding royalties, to which Cenovus is entitled.
8. **Royalty Interest Production** means the production related to Cenovus's royalty entitlement on lands to which the Company holds fee title and which have been leased to third parties, plus any production related to other royalty interests, such as overriding royalties, to which Cenovus is entitled.

Pricing Assumptions

The forecast price and cost assumptions assume the continuance of current laws and take into account inflation with respect to future operating and capital costs. The forecast prices are provided in the table below and reflect McDaniel's January 1, 2015 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2015. For historical prices realized during 2014, see "Production History" in this AIF.

	Oil					Natural Gas		
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40 API ($C/bbl)	Cromer Medium 29.3 API ($C/bbl)	Hardisty Heavy 12 API ($C/bbl)	Western Canadian Select ($C/bbl)	AECO Gas Price ($C/MMBtu)	Inflation Rate (%/year)	Exchange Rate ($US/$C)
2015	65.00	68.60	64.50	51.10	57.60	3.50	2	0.860
2016	75.00	83.20	78.20	62.00	69.90	4.00	2	0.860
2017	80.00	88.90	83.60	66.20	74.70	4.25	2	0.860
2018	84.90	94.60	88.90	70.50	79.50	4.50	2	0.860
2019	89.30	99.60	93.60	74.20	83.70	4.70	2	0.860
2020	93.80	104.70	98.40	78.00	87.90	5.00	2	0.860
2021	95.70	106.90	100.50	79.60	89.80	5.30	2	0.860
2022	97.60	109.00	102.50	81.20	91.60	5.50	2	0.860
2023	99.60	111.20	104.50	82.80	93.40	5.70	2	0.860
2024	101.60	113.50	106.70	84.60	95.30	5.90	2	0.860
2025	103.60	115.70	108.80	86.20	97.20	6.00	2	0.860
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2	0.860

Future Development Costs

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

Reserves Category ($ millions)	2015	2016	2017	2018	2019	Remainder	Total
Proved Reserves	1,231	834	949	1,004	1,044	15,022	20,084
Proved plus Probable Reserves	1,437	1,531	1,390	1,341	1,305	31,472	38,476

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 Company'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 Company's future net revenue.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce future net revenue 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 for the year ended December 31, 2014, presented using forecast prices and costs. All reserves are located in Canada.

Company Interest Before Royalties
Reserves Reconciliation by Principal Product Type and Reserves Category
(Forecast Prices and Costs)

Proved	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2013	1,846	179	115	865
Extensions and Improved Recovery	108	14	17	23
Discoveries	-	-	-	-
Technical Revisions	63	(13)	1	98
Economic Factors	-	-	-	(12)
Acquisitions	-	-	-	2
Dispositions	-	(10)	(1)	(5)
Production (1)	(47)	(14)	(12)	(175)
As at December 31, 2014	1,970	156	120	796

Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2013	683	140	50	300
Extensions and Improved Recovery	648	7	-	13
Discoveries	-	-	-	-
Technical Revisions	(1)	(21)	(3)	(47)
Economic Factors	-	-	-	(5)
Acquisitions	-	-	-	-
Dispositions	-	(3)	(1)	(1)
Production (1)	-	-	-	-
As at December 31, 2014	1,330	123	46	260

Proved plus Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
As at December 31, 2013	2,529	319	165	1,165
Extensions and Improved Recovery	756	21	17	36
Discoveries	-	-	-	-
Technical Revisions	62	(34)	(2)	51
Economic Factors	-	-	-	(17)
Acquisitions	-	-	-	2
Dispositions	-	(13)	(2)	(6)
Production (1)	(47)	(14)	(12)	(175)
As at December 31, 2014	3,300	279	166	1,056

(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 and proved plus probable bitumen reserves increased by approximately seven and 30 percent, respectively. Increases at Christina Lake were primarily a result of a large area expansion and improved reservoir performance. Increases at Foster Creek were primarily a result of receiving regulatory approval for expansion of the development area.

Heavy oil proved reserves decreased by approximately 13 percent primarily as a result of production and drilling deferrals, the disposition of Wainwright assets partially offset by expanded polymer flooding and infill drilling at Pelican Lake, and the recognition of horizontal well development at Elk Point. Heavy oil probable reserves decreased by approximately 12 percent due to drilling deferrals at Pelican Lake. Overall, heavy oil proved plus probable reserves decreased by approximately 13 percent.

Light and medium oil and NGLs proved reserves increased by four percent. The increases were due to waterflood and CO_2 flood areas at Weyburn and development at Grassland. Light and medium oil and NGLs probable reserves decreased by approximately eight percent primarily as a result of the conversion of probable reserves to proved reserves. Overall, light and medium oil and NGLs proved plus probable reserves increased slightly, primarily as a result of the Weyburn CO_2 flood expansion, partially offset by production and the Bakken disposition.

Natural gas proved reserves declined by approximately eight percent as extensions and technical revisions did not offset production. Probable natural gas reserves and proved plus probable natural gas reserves declined by approximately 13 percent and nine 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 ("COGE") Handbook. In general, undeveloped reserves are scheduled to be developed within the next one to 40 years.

Company Interest Proved Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil and 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	1,433	1,287	73	55	53	25	300	24
2012	284	1,532	20	61	3	22	-	6
2013	158	1,629	1	47	3	15	-	4
2014	161	1,732	7	40	11	21	4	4

Company Interest Probable Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil and 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	917	467	57	47	29	22	54	35
2012	182	646	9	42	5	24	-	16
2013	145	649	56	86	1	17	-	16
2014	649	1,293	5	76	8	15	7	11

DEVELOPMENT OF PROVED AND PROBABLE UNDEVELOPED RESERVES

Bitumen

At the end of 2014, Cenovus had proved undeveloped bitumen reserves of 1,732 million barrels Before Royalties, or approximately 88 percent of the Company's total proved bitumen reserves. Of Cenovus's 1,330 million barrels of probable bitumen reserves, 1,293 million barrels, or approximately 97 percent are undeveloped. The evaluation of these reserves anticipates they will be recovered using SAGD technology.

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. The IQRE'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 or the Grosmont carbonates, 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. The IQRE'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 plan 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 about 14 years.

Crude Oil

Cenovus has a significant medium oil CO_2 enhanced oil recovery ("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 35 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 five 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".

CONTINGENT AND PROSPECTIVE RESOURCES

Cenovus retains McDaniel to evaluate and prepare reports on all of the Company's contingent and prospective bitumen resources. The evaluations by McDaniel are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that McDaniel is in receipt of all relevant information. Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. The assets currently producing from the McMurray-Wabiskaw formation at Foster Creek and Christina Lake are used as performance analogs for contingent and prospective resources estimation within these areas. Other regional analogs are 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 tests contingent resources for economic viability using the same forecast prices and costs used for Cenovus's reserves (refer to "Pricing Assumptions" in this AIF).

This evaluation assumes that the vast majority of Cenovus's bitumen resources will be recovered and produced using SAGD, with only a minor portion of the Company's resources likely to be developed using cyclic steam stimulation ("CSS") established technologies. 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. CSS involves injecting steam into a well and then producing water and heated bitumen from the same wellbore. Such alternating injection and production cycles are repeated a number of times for a given wellbore. Both of these techniques have a surface footprint comparable to conventional oil production. Cenovus has no bitumen resources that require mining techniques for recovery.

All of Cenovus's current 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 is currently underway in the Grosmont carbonate formation several miles away from Cenovus's lands but commercial viability has yet to be established. Cenovus has commenced work on its own pilot for bitumen production from the Grosmont carbonate formation.

In addition to the reserve definitions provided in the preceding sections, the following terminology, consistent with the COGE Handbook and guidance from Canadian securities regulatory authorities, was used to prepare the disclosure that follows:

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 there is still considerable uncertainty around the development of these volumes.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. Only those bitumen contingent resources based on established technology and determined to be economic using the same commodity price assumptions that were used for the 2014 reserves evaluation are disclosed in this AIF.

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 the Greater Pelican Region. At Foster Creek and Christina Lake, Cenovus has economic contingent resources located outside the currently approved development project areas. Regulatory approval to expand the development 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 that maximizes utilization of steam generation facilities and ultimately optimizes 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 an initial development project at the Grand Rapids property. Pilot project work continues to validate technical assumptions and examine optimal development strategies. Reclassification of contingent resources to reserves in the Greater Pelican Region is contingent upon justification of a large scale project development, further regulatory approval for development, and project sanctioning.

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.

Low estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources included in the low estimate have the highest degree of certainty, a 90 percent probability, that the actual quantities recovered will equal or exceed the estimate.

High estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources included in the high estimate have a lower degree of certainty, a 10 percent probability, that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated for individual projects and then aggregated for disclosure purposes. The high and low estimate volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Because the results are aggregated for disclosure, the low estimate results disclosed may have a higher probability than the estimates for the individual projects, and the high estimate results disclosed may have a lower probability than the estimates for individual projects.

Bitumen Economic Contingent and Prospective Resources

Company Interest Before Royalties (Billions of Barrels)	**December 31, 2014**	December 31, 2013
Economic Contingent Resources (1)		
Low Estimate	**6.6**	7.0
Best Estimate	**9.3**	9.8
High Estimate	**12.9**	13.6
Prospective Resources (2)		
Low Estimate	**4.4**	4.5
Best Estimate	**7.5**	7.5
High Estimate	**12.7**	12.6

(1) There is no certainty 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.

Bitumen best estimate economic contingent resources decreased by 0.5 billion barrels or five percent compared to 2013. This decrease is primarily a result of a substantial conversion of contingent resources to proved and probable reserves at Christina Lake and Foster Creek.

Bitumen best estimate prospective resources stayed consistent with 2013, primarily due to conversions to contingent resources at Borealis attributed to stratigraphic drilling being offset by mapping increases at Grand Rapids.

A more detailed annual reconciliation is shown in the following table:

Bitumen Proved plus Probable Reserves, Contingent Resources 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, 2013	2.529	9.8	7.5
Transfers Between Categories			
Additions From Other Resource Categories	0.756	-	-
Reductions to Other Resource Categories	-	(0.8)	-
Additions and Revisions net of Transfers	0.060	0.3	-
Net Acquisitions and Dispositions	-	-	-
Production	(0.045)	-	-
As at December 31, 2014	3.300	9.3	7.5

(1) There is no certainty 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.

Cenovus is systematically progressing the classification of its bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, the stratigraphic well drilling program in the Borealis area moved some prospective resources to contingent resources. The overall reduction of prospective resources is the expected outcome of a successful stratigraphic well drilling program, which converts undiscovered resources to discovered resources.

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, 2014:

	Oil		Gas		Total	
Producing Wells (1) (2)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	407	207	286	274	693	481
Conventional	2,169	2,144	24,328	24,139	26,497	26,283
Total Alberta	2,576	2,351	24,614	24,413	27,190	26,764
Saskatchewan	667	418	-	-	667	418
Total	3,243	2,769	24,614	24,413	27,857	27,182

(1) *Excludes varying royalty interests in 9,023 natural gas wells and 3,852 crude oil wells which are producing.*

(2) *Includes wells containing multiple completions as follows: 22,199 gross natural gas wells (22,036 net wells) and 1,240 gross crude oil wells (1,117 net wells).*

	Oil		Gas		Total	
Non-Producing Wells (1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	21	13	446	335	467	348
Conventional	767	747	981	952	1,748	1,699
Total Alberta	788	760	1,427	1,287	2,215	2,047
Saskatchewan	138	91	7	7	145	98
Total	926	851	1,434	1,294	2,360	2,145

(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 for the periods indicated:

	Oil Sands		Conventional		Total	
Exploration Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2014:						
Oil	**-**	**-**	**1**	**1**	**1**	**1**
Gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry & Abandoned	**-**	**-**	**-**	**-**	**-**	**-**
Total Working Interest	**-**	**-**	**1**	**1**	**1**	**1**
Royalty	**-**	**-**	**10**	**-**	**10**	**-**
Total Canada	**-**	**-**	**11**	**1**	**11**	**1**
2013:						
Oil	-	-	6	6	6	6
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	-	-	-	-
Total Working Interest	-	-	6	6	6	6
Royalty	-	-	9	-	9	-
Total Canada	-	-	15	6	15	6
2012:						
Oil	-	-	8	7	8	7
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	-	-	-	-
Total Working Interest	-	-	8	7	8	7
Royalty	-	-	20	-	20	-
Total Canada	-	-	28	7	28	7

Development Wells Drilled	Oil Sands Gross	Oil Sands Net	Conventional Gross	Conventional Net	Total Gross	Total Net
2014:						
Oil	**130**	**65**	**129**	**125**	**259**	**190**
Gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry & Abandoned	**-**	**-**	**7**	**7**	**7**	**7**
Total Working Interest	**130**	**65**	**136**	**132**	**266**	**197**
Royalty	**1**	**-**	**126**	**-**	**127**	**-**
Total Canada	**131**	**65**	**262**	**132**	**393**	**197**
2013:						
Oil	91	46	215	206	306	252
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	2	2	2	2
Total Working Interest	91	46	217	208	308	254
Royalty	3	-	117	-	120	-
Total Canada	94	46	334	208	428	254
2012:						
Oil	61	31	349	345	410	376
Gas	-	-	-	-	-	-
Dry & Abandoned	-	-	1	1	1	1
Total Working Interest	61	31	350	346	411	377
Royalty	57	-	129	-	186	-
Total Canada	118	31	479	346	597	377

During the year ended December 31, 2014, Oil Sands drilled 320 gross stratigraphic test wells (196 net wells) and Conventional drilled 30 gross stratigraphic test wells (30 net wells).

During the year ended December 31, 2014, Oil Sands drilled three gross service wells (two net wells) and Conventional drilled 38 gross service wells (33 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.

Interest in Material Properties

The following table summarizes Cenovus's landholdings as at December 31, 2014:

Landholdings (thousands of acres)	Developed Gross	Developed Net	Undeveloped (1) Gross	Undeveloped (1) Net	Total (2) Gross	Total (2) Net
Alberta:						
Oil Sands						
– Crown (3)	485	383	1,857	1,398	2,342	1,781
Conventional						
– Fee (4)	1,935	1,935	433	433	2,368	2,368
– Crown (3)	1,157	1,054	542	476	1,699	1,530
– Freehold (5)	68	58	12	10	80	68
Total Alberta	3,645	3,430	2,844	2,317	6,489	5,747
Saskatchewan:						
Oil Sands						
– Crown (3)	-	-	63	63	63	63
Conventional						
– Fee (4)	81	81	424	424	505	505
– Crown (3)	42	28	99	88	141	116
– Freehold (5)	14	10	6	3	20	13
Total Saskatchewan	137	119	592	578	729	697
Manitoba:						
Conventional						
– Fee (4)	5	5	252	252	257	257
Total Manitoba	5	5	252	252	257	257
Total	3,787	3,554	3,688	3,147	7,475	6,701

(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) Includes approximately 1.1 million gross acres partially leased to third parties and excludes approximately 1.3 million gross acres fully leased to third parties.

(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which Cenovus has purchased a working interest lease.

(4) Fee lands are those lands in which Cenovus has a fee simple interest in the mineral rights and have either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands summary includes all freehold titles owned by Cenovus that have one or more zones that remain unleased or available for development.

(5) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

Properties With No Attributed Reserves

Cenovus has approximately 5.0 million gross acres (4.4 million net acres) of properties to which no reserves have been specifically attributed. These properties are planned for current and future development in both the Company'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 79,000 net acres that could potentially expire by December 31, 2015, 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 Company 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, fee title holdings and crown lands where exploration activities to date have not identified potential reserves in commercial quantities. See "Risk Factors – Financial Risks – Commodity Price Volatility and Development and Operating Costs" and "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates and Uncertainty of Contingent and Prospective Resource 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 & Reclamation Costs

The estimated total future abandonment and reclamation costs 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 the undiscounted future cost of abandonment and reclamation costs at approximately $8.3 billion (approximately $1.3 billion, discounted at 10 percent) at December 31, 2014, of which the Company expects to pay between $250 million and $350 million in the next three financial years. Cenovus expects to incur these costs on approximately 34,945 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Cenovus's proved reserves, approximately $1.4 billion has been deducted in estimating the future net revenue, which only represents the Company's downhole abandonment obligations for wells within reserves.

Tax Horizon

Cenovus expects to pay income tax in 2015.

Costs Incurred

($ millions)	2014
Acquisitions	
– Unproved	16
– Proved	2
Total Acquisitions	18
Exploration Costs	159
Development Costs	2,623
Total Costs Incurred	2,800

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 Company's annual audited Consolidated Financial Statements for the year ended December 31, 2014.

Production Estimates

The following table summarizes the estimated 2015 average daily volume of Company Interest Before Royalties and Royalty Interest Production reflected in the reserves reports for all properties held on December 31, 2014 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.

2015 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d) [1]	127,463	134,766
Light and Medium Oil (bbls/d)	31,997	35,228
Heavy Oil (bbls/d)	37,241	39,194
Natural Gas (MMcf/d)	392	424
Natural Gas Liquids (bbls/d)	715	789
Company Interest Before Royalties Production (BOE/d)	262,776	280,562
Royalty Interest Production (BOE/d)	6,491	6,766
Total Company Interest Before Royalties Plus Royalty Interest Production (BOE/d)	269,267	287,328

(1) *Includes Foster Creek production of 61,438 barrels per day for Proved and 63,312 barrels per day for Proved plus Probable, and Christina Lake production of 66,025 barrels per day for Proved and 71,454 barrels per day for Proved plus Probable.*

Production History

Average Before Royalties Daily Production Volumes – 2014

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	59,172	68,377	56,631	56,852	54,706
Christina Lake (Bitumen)	69,023	73,836	68,458	67,975	65,738
	128,195	142,213	125,089	124,827	120,444
Conventional Liquids					
Heavy Oil – Pelican Lake	24,924	25,906	24,196	24,806	24,782
Heavy Oil – Other [2]	13,630	11,144	13,996	14,404	15,018
Light and Medium Oil	31,296	31,505	30,416	32,042	31,228
Natural Gas Liquids [1]	1,060	1,116	1,165	1,091	866
Total Crude Oil and Natural Gas Liquids	199,105	211,884	194,862	197,170	192,338
Natural Gas (MMcf/d)					
Oil Sands	22	22	23	23	19
Conventional	446	438	446	465	435
Total Natural Gas	468	460	469	488	454
Total (BOE/d)	277,105	288,551	273,029	278,503	268,005

(1) *Natural gas liquids include condensate volumes.*
(2) *Cenovus sold certain interest in its Wainwright crude oil assets late in the third quarter of 2014.*

Average Royalty Interest Daily Production Volumes – 2014

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil – Other [2]	992	971	904	1,094	999
Light and Medium Oil	3,235	3,156	3,132	3,287	3,370
Natural Gas Liquids [1]	161	166	191	137	147
Total Crude Oil and Natural Gas Liquids	4,388	4,293	4,227	4,518	4,516
Natural Gas (MMcf/d)					
Conventional	20	19	20	19	22
Total (BOE/d)	7,721	7,460	7,560	7,685	8,183

(1) *Natural gas liquids include condensate volumes.*
(2) *Cenovus sold certain interest in its Wainwright crude oil assets late in the third quarter of 2014.*

Average Before Royalties Daily Production Volumes – 2013

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	53,190	52,419	49,092	55,338	55,996
Christina Lake (Bitumen)	49,310	61,471	52,732	38,459	44,351
	102,500	113,890	101,824	93,797	100,347
Conventional Liquids					
Heavy Oil – Pelican Lake	24,254	24,528	24,826	23,959	23,687
Heavy Oil – Other	14,901	14,487	14,451	15,182	15,500
Light and Medium Oil	31,926	30,030	30,509	32,195	35,041
Natural Gas Liquids (1)	901	1,033	1,039	735	794
Total Crude Oil and Natural Gas Liquids	174,482	183,968	172,649	165,868	175,369
Natural Gas (MMcf/d)					
Oil Sands	21	21	23	22	18
Conventional	485	471	479	489	503
Total Natural Gas	506	492	502	511	521
Total (BOE/d)	258,815	265,968	256,316	251,035	262,202

(1) Natural gas liquids include condensate volumes.

Average Royalty Interest Daily Production Volumes – 2013

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil - Other	1,090	993	1,056	1,102	1,212
Light and Medium Oil	3,541	3,616	3,142	3,942	3,467
Natural Gas Liquids (1)	162	166	91	215	177
Total Crude Oil and Natural Gas Liquids	4,793	4,775	4,289	5,259	4,856
Natural Gas (MMcf/d)					
Conventional	23	22	21	25	24
Total (BOE/d)	8,626	8,442	7,789	9,426	8,856

(1) Natural gas liquids include condensate volumes.

Average Before Royalties Daily Production Volumes – 2012

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	57,833	59,059	63,245	51,740	57,214
Christina Lake (Bitumen)	31,903	41,808	32,380	28,577	24,733
	89,736	100,867	95,625	80,317	81,947
Conventional Liquids					
Heavy Oil – Pelican Lake	22,552	23,507	23,539	22,410	20,730
Heavy Oil – Other	14,862	15,073	14,398	14,559	15,418
Light and Medium Oil	32,115	32,482	32,121	32,213	31,641
Natural Gas Liquids (1)	835	805	827	799	912
Total Crude Oil and Natural Gas Liquids	160,100	172,734	166,510	150,298	150,648
Natural Gas (MMcf/d)					
Oil Sands	30	27	24	31	39
Conventional	538	514	532	538	566
Total Natural Gas	568	541	556	569	605
Total (BOE/d)	254,767	262,901	259,177	245,131	251,481

(1) Natural gas liquids include condensate volumes.

Average Royalty Interest Daily Production Volumes - 2012

	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil – Other	1,153	1,170	1,094	1,144	1,206
Light and Medium Oil	3,956	3,552	3,574	3,936	4,770
Natural Gas Liquids (1)	194	190	172	188	226
Total Crude Oil and Natural Gas Liquids	5,303	4,912	4,840	5,268	6,202
Natural Gas (MMcf/d)					
Conventional	26	25	21	27	31
Total (BOE/d)	9,636	9,079	8,340	9,768	11,369

(1) Natural gas liquids include condensate volumes.

Per-Unit Results

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

Per-Unit Results – 2014

(excluding impact of Realized Gain (Loss) on Risk Management)	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl) (1) (2) (3)					
Price	69.43	51.95	76.82	79.77	71.44
Royalties	5.95	5.67	5.40	7.14	5.71
Transportation and blending	1.98	1.85	2.17	3.10	0.78
Operating	16.55	13.65	14.79	19.38	19.09
Netback	44.95	30.78	54.46	50.15	45.86
Heavy Oil – Christina Lake ($/bbl) (1) (2) (3)					
Price	61.57	47.21	67.62	72.25	59.89
Royalties	4.40	3.14	5.07	5.37	4.04
Transportation and blending	3.53	4.14	3.75	3.14	3.02
Operating	11.20	9.31	10.40	12.08	13.30
Netback	42.44	30.62	48.40	51.66	39.53
Total Heavy Oil – Oil Sands ($/bbl) (2) (3)					
Price	65.18	49.44	71.82	75.65	65.19
Royalties	5.11	4.33	5.22	6.17	4.80
Transportation and blending	2.82	3.06	3.03	3.12	1.99
Operating	13.66	11.35	12.41	15.38	15.96
Netback	43.59	30.70	51.16	50.98	42.44
Heavy Oil – Pelican Lake ($/bbl) (2) (3)					
Price	76.07	61.24	81.66	84.66	76.20
Royalties	5.50	4.86	5.56	6.50	5.04
Transportation and blending	3.18	3.29	3.24	3.13	3.07
Operating	21.41	18.84	20.49	21.23	24.96
Netback	45.98	34.25	52.37	53.80	43.13
Heavy Oil – Other Conventional ($/bbl) (2) (3)					
Price	76.55	58.31	80.74	81.09	82.14
Royalties	9.70	10.71	11.10	9.77	7.52
Transportation and blending	3.47	3.07	3.64	3.94	3.13
Operating	19.63	17.09	19.29	19.74	21.81
Production and mineral taxes	0.48	0.08	0.61	0.84	0.32
Netback	43.27	27.36	46.10	46.80	49.36
Total Heavy Oil – Conventional ($/bbl) (2) (3)					
Price	76.25	60.25	81.30	83.29	78.52
Royalties	7.09	6.85	7.72	7.76	6.01
Transportation and blending	3.29	3.22	3.40	3.44	3.09
Operating	20.74	18.24	20.02	20.66	23.73
Production and mineral taxes	0.18	0.03	0.24	0.32	0.13
Netback	44.95	31.91	49.92	51.11	45.56
Total Heavy Oil ($/bbl) (2) (3)					
Price	67.83	51.74	73.99	77.63	68.64
Royalties	5.59	4.87	5.79	6.58	5.12
Transportation and blending	2.93	3.09	3.11	3.20	2.28
Operating	15.35	12.82	14.15	16.75	17.97
Production and mineral taxes	0.04	0.01	0.05	0.08	0.03
Netback	43.92	30.95	50.89	51.02	43.24

(1) Foster Creek and Christina Lake are bitumen properties.
(2) Netbacks do not reflect non-cash write-downs of product inventory.
(3) Cost of condensate per barrel of unblended crude oil ($/bbl).

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

Foster Creek	*42.01*	*35.45*	*38.50*	*47.28*	*48.35*
Christina Lake	*45.45*	*38.23*	*42.57*	*49.30*	*52.81*
Heavy Oil – Oil Sands	*43.87*	*36.92*	*40.71*	*48.39*	*50.77*
Pelican Lake	*15.86*	*14.70*	*12.64*	*17.55*	*18.30*
Other Conventional Heavy Oil	*15.46*	*12.58*	*14.20*	*17.94*	*16.40*
Heavy Oil – Conventional	*15.71*	*13.98*	*13.25*	*17.70*	*17.56*
Total Heavy Oil	*37.13*	*32.04*	*34.42*	*40.44*	*42.17*

Per-Unit Results – 2014 (excluding impact of Realized Gain (Loss) on Risk Management)	Year	Q4	Q3	Q2	Q1
Light and Medium Oil ($/bbl)					
Price	88.30	71.10	89.85	98.27	94.18
Royalties	9.15	6.12	10.36	11.37	8.78
Transportation and blending	3.34	2.89	3.06	3.31	4.11
Operating	17.28	15.84	17.40	17.45	18.47
Production and mineral taxes	2.70	2.59	2.99	2.97	2.23
Netback	55.83	43.66	56.04	63.17	60.59
Total Crude Oil ($/bbl) (1)					
Price	71.39	55.05	76.64	81.35	73.15
Royalties	6.21	5.08	6.56	7.45	5.76
Transportation and blending	3.00	3.06	3.10	3.22	2.60
Operating	15.69	13.34	14.70	16.87	18.06
Production and mineral taxes	0.50	0.45	0.54	0.60	0.42
Netback	45.99	33.12	51.74	53.21	46.31
Natural Gas Liquids ($/bbl)					
Price	65.55	50.82	66.70	78.38	67.31
Royalties	1.38	1.34	1.07	1.70	1.48
Netback	64.17	49.48	65.63	76.68	65.83
Total Liquids ($/bbl) (1)					
Price	71.35	55.02	76.57	81.33	73.12
Royalties	6.18	5.06	6.52	7.41	5.74
Transportation and blending	2.98	3.04	3.08	3.20	2.59
Operating	15.59	13.25	14.60	16.77	17.96
Production and mineral taxes	0.50	0.44	0.54	0.60	0.42
Netback	46.10	33.23	51.83	53.35	46.41
Total Natural Gas ($/Mcf)					
Price	4.37	3.89	4.22	4.87	4.47
Royalties	0.08	0.09	0.08	0.09	0.06
Transportation and blending	0.12	0.13	0.11	0.11	0.11
Operating	1.23	1.21	1.24	1.23	1.26
Production and mineral taxes	0.05	0.03	0.05	0.13	(0.01)
Netback	2.89	2.43	2.74	3.31	3.05
Total ($/BOE) (1)					
Price	58.29	46.14	61.85	65.71	59.68
Royalties	4.53	3.80	4.79	5.36	4.19
Transportation and blending	2.32	2.40	2.39	2.45	2.03
Operating	13.22	11.57	12.53	13.95	14.94
Production and mineral taxes	0.44	0.36	0.48	0.65	0.28
Netback	37.78	28.01	41.66	43.30	38.24

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

Impact of Long-term Incentive Costs (Recovery) on Total Operating Costs – 2014	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.16	(0.09)	0.08	0.36	0.29

Impact of Realized Gain (Loss) on Risk Management – 2014	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	0.50	7.06	(0.45)	(2.94)	(2.00)
Natural Gas ($/Mcf)	0.04	0.05	0.11	(0.02)	-
Total ($/BOE)	0.42	5.17	(0.13)	(2.09)	(1.42)

Per-Unit Results – 2013

(excluding impact of Realized Gain (Loss) on Risk Management)	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl) (1) (2)					
Price	66.30	59.39	87.49	68.17	52.60
Royalties	3.73	3.56	6.31	3.87	1.47
Transportation and blending	2.36	3.21	4.37	0.04	1.89
Operating	15.77	15.90	17.12	16.19	14.03
Netback	44.44	36.72	59.69	48.07	35.21
Heavy Oil – Christina Lake ($/bbl) (1) (2)					
Price	51.26	44.36	74.98	52.61	33.41
Royalties	3.25	3.22	5.06	2.71	1.69
Transportation and blending	3.55	3.29	3.16	4.45	3.67
Operating	12.47	10.57	11.46	16.83	12.93
Netback	31.99	27.28	55.30	28.62	15.12
Total Heavy Oil – Oil Sands ($/bbl) (2)					
Price	59.10	51.34	81.16	61.88	44.01
Royalties	3.50	3.37	5.68	3.40	1.57
Transportation and blending	2.93	3.25	3.76	1.82	2.69
Operating	14.19	13.04	14.26	16.45	13.53
Netback	38.48	31.68	57.46	40.21	26.22
Heavy Oil – Pelican Lake ($/bbl) (2)					
Price	70.09	64.52	88.08	72.32	54.30
Royalties	4.00	1.97	6.64	4.08	3.22
Transportation and blending	2.41	2.79	2.18	2.58	2.07
Operating	20.65	21.22	19.90	22.21	19.23
Netback	43.03	38.54	59.36	43.45	29.78
Heavy Oil – Other Conventional ($/bbl) (2)					
Price	70.65	64.58	86.58	70.81	61.62
Royalties	9.18	10.40	12.27	7.67	6.57
Transportation and blending	2.90	2.54	3.04	2.59	3.39
Operating	17.34	17.54	16.32	17.38	18.04
Production and mineral taxes	0.31	0.12	0.55	0.30	0.30
Netback	40.92	33.98	54.40	42.87	33.32
Total Heavy Oil – Conventional ($/bbl) (2)					
Price	70.31	64.55	87.50	71.73	57.42
Royalties	6.08	5.31	8.83	5.50	4.65
Transportation and blending	2.60	2.69	2.51	2.58	2.63
Operating	19.32	19.76	18.51	20.30	18.72
Production and mineral taxes	0.13	0.05	0.21	0.12	0.13
Netback	42.18	36.74	57.44	43.23	31.29
Total Heavy Oil ($/bbl) (2)					
Price	62.23	54.61	82.97	64.91	47.82
Royalties	4.22	3.85	6.58	4.05	2.45
Transportation and blending	2.84	3.11	3.40	2.06	2.67
Operating	15.62	14.70	15.47	17.63	15.01
Production and mineral taxes	0.04	0.01	0.06	0.04	0.04
Netback	39.51	32.94	57.46	41.13	27.65

(1) Foster Creek and Christina Lake are bitumen properties.

(2) Cost of condensate per barrel of unblended crude oil ($/bbl).

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

Foster Creek	*42.41*	*41.85*	*38.85*	*42.60*	*46.00*
Christina Lake	*45.25*	*44.16*	*39.86*	*47.13*	*51.46*
Heavy Oil – Oil Sands	*43.77*	*43.09*	*39.39*	*44.43*	*48.44*
Pelican Lake	*15.59*	*13.58*	*12.09*	*16.74*	*20.31*
Other Conventional Heavy Oil	*13.12*	*10.05*	*10.96*	*16.68*	*14.73*
Heavy Oil – Conventional	*14.60*	*12.18*	*11.65*	*16.72*	*17.93*
Total Heavy Oil	*35.63*	*35.44*	*31.46*	*35.91*	*39.78*

Per-Unit Results – 2013 (excluding impact of Realized Gain (Loss) on Risk Management)	Year	Q4	Q3	Q2	Q1
Light and Medium Oil ($/bbl)					
Price	86.30	82.12	100.64	86.84	76.77
Royalties	8.28	6.58	11.01	8.61	7.05
Transportation and blending	4.35	5.15	4.58	4.37	3.39
Operating	16.23	17.26	15.06	16.32	16.26
Production and mineral taxes	2.30	1.26	2.80	2.64	2.46
Netback	55.14	51.87	67.19	54.90	47.61
Total Crude Oil ($/bbl)					
Price	67.05	59.41	86.41	69.75	54.02
Royalties	5.03	4.33	7.44	5.05	3.43
Transportation and blending	3.14	3.47	3.63	2.57	2.82
Operating	15.74	15.15	15.39	17.34	15.27
Production and mineral taxes	0.49	0.23	0.59	0.61	0.56
Netback	42.65	36.23	59.36	44.18	31.94
Natural Gas Liquids ($/bbl)					
Price	60.34	59.39	65.71	46.44	68.88
Royalties	1.13	1.14	1.92	1.17	0.12
Netback	59.21	58.25	63.79	45.27	68.76
Total Liquids ($/bbl)					
Price	67.01	59.41	86.28	69.61	54.10
Royalties	5.01	4.31	7.40	5.03	3.42
Transportation and blending	3.12	3.45	3.61	2.55	2.81
Operating	15.65	15.06	15.29	17.24	15.19
Production and mineral taxes	0.48	0.23	0.59	0.61	0.55
Netback	42.75	36.36	59.39	44.18	32.13
Total Natural Gas ($/Mcf)					
Price	3.20	3.21	2.83	3.50	3.25
Royalties	0.04	0.04	0.05	0.04	0.05
Transportation and blending	0.11	0.11	0.10	0.08	0.15
Operating	1.16	1.23	1.13	1.16	1.14
Production and mineral taxes	0.02	0.02	0.03	(0.01)	0.03
Netback	1.87	1.81	1.52	2.23	1.88
Total ($/BOE)					
Price	51.23	47.23	63.12	52.55	42.52
Royalties	3.44	3.07	5.02	3.35	2.38
Transportation and blending	2.31	2.60	2.60	1.82	2.17
Operating	12.79	12.73	12.44	13.64	12.39
Production and mineral taxes	0.36	0.19	0.45	0.38	0.42
Netback	32.33	28.64	42.61	33.36	25.16

Impact of Long-term Incentive Costs (Recovery) on Total Operating Costs – 2013	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.12	0.06	0.23	0.07	0.10

Impact of Realized Gain (Loss) on Risk Management – 2013	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	1.09	2.77	(2.02)	0.72	2.62
Natural Gas ($/Mcf)	0.32	0.36	0.38	0.18	0.39
Total ($/BOE)	1.37	2.58	(0.58)	0.84	2.52

Per-Unit Results – 2012
(excluding impact of Realized Gain (Loss) on Risk Management)

	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl) (1) (2)					
Price	64.55	59.93	63.95	63.83	70.71
Royalties	7.36	4.55	11.79	2.85	9.54
Transportation and blending	2.41	2.91	2.38	1.91	2.38
Operating	11.99	11.26	11.50	12.49	12.85
Netback	42.79	41.21	38.28	46.58	45.94
Heavy Oil – Christina Lake ($/bbl) (1) (2)					
Price	47.73	43.37	52.91	44.57	52.58
Royalties	2.72	2.32	2.61	2.90	3.37
Transportation and blending	3.79	3.00	4.00	4.12	4.51
Operating	12.95	11.42	13.59	12.52	15.33
Netback	28.27	26.63	32.71	25.03	29.37
Total Heavy Oil – Oil Sands ($/bbl) (2)					
Price	58.61	53.02	60.35	57.02	65.23
Royalties	5.72	3.62	8.80	2.87	7.68
Transportation and blending	2.90	2.95	2.91	2.69	3.02
Operating	12.33	11.33	12.17	12.52	13.60
Netback	37.66	35.12	36.47	38.94	40.93
Heavy Oil – Pelican Lake ($/bbl) (2)					
Price	69.23	64.37	66.75	66.42	78.50
Royalties	3.34	2.82	4.34	2.68	3.37
Transportation and blending	2.15	1.23	1.09	3.54	2.88
Operating	17.08	17.20	17.47	17.71	16.05
Netback	46.66	43.12	43.85	42.49	56.20
Heavy Oil – Other Conventional ($/bbl) (2)					
Price	70.53	64.73	68.04	67.70	80.64
Royalties	10.06	8.68	8.81	9.36	13.06
Transportation and blending	2.17	2.34	2.31	2.26	1.81
Operating	15.21	11.68	16.48	15.07	17.57
Production and mineral taxes	0.24	0.31	0.27	0.25	0.14
Netback	42.85	41.72	40.17	40.76	48.06
Total Heavy Oil – Conventional ($/bbl) (2)					
Price	69.76	64.52	67.25	66.95	79.37
Royalties	6.06	5.26	6.05	5.46	7.33
Transportation and blending	2.16	1.69	1.55	3.01	2.44
Operating	16.32	14.91	17.09	16.61	16.67
Production and mineral taxes	0.10	0.13	0.10	0.10	0.06
Netback	45.12	42.53	42.46	41.77	52.87
Total Heavy Oil ($/bbl) (2)					
Price	62.05	56.22	62.45	60.13	70.08
Royalties	5.83	4.07	7.96	3.68	7.56
Transportation and blending	2.67	2.60	2.50	2.79	2.82
Operating	13.56	12.33	13.66	13.80	14.65
Production and mineral taxes	0.03	0.04	0.03	0.03	0.02
Netback	39.96	37.18	38.30	39.83	45.03

(1) Foster Creek and Christina Lake are bitumen properties.
(2) Cost of condensate per barrel of unblended crude oil ($/bbl).

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

Foster Creek	*41.85*	*38.31*	*36.33*	*45.06*	*48.70*
Christina Lake	*45.83*	*43.39*	*39.88*	*48.80*	*53.90*
Heavy Oil – Oil Sands	*43.26*	*40.43*	*37.49*	*46.38*	*50.27*
Pelican Lake	*15.55*	*14.28*	*11.34*	*17.32*	*19.39*
Other Conventional Heavy Oil	*13.35*	*12.36*	*11.49*	*13.48*	*15.82*
Heavy Oil – Conventional	*14.66*	*13.48*	*11.40*	*15.72*	*17.93*
Total Heavy Oil	*34.44*	*32.92*	*29.56*	*36.78*	*39.19*

Per-Unit Results – 2012 (excluding impact of Realized Gain (Loss) on Risk Management)	Year	Q4	Q3	Q2	Q1
Light and Medium Oil ($/bbl)					
Price	78.99	75.27	76.06	76.16	88.45
Royalties	8.09	6.92	7.53	7.98	9.94
Transportation and blending	2.65	2.39	2.36	3.02	2.83
Operating	15.51	15.63	16.27	14.76	15.36
Production and mineral taxes	2.44	2.51	2.35	2.34	2.57
Netback	50.30	47.82	47.55	48.06	57.75
Total Crude Oil ($/bbl)					
Price	65.76	60.10	65.37	63.91	74.22
Royalties	6.32	4.65	7.87	4.69	8.10
Transportation and blending	2.66	2.55	2.47	2.84	2.83
Operating	13.99	13.00	14.22	14.03	14.81
Production and mineral taxes	0.56	0.54	0.53	0.58	0.59
Netback	42.23	39.36	40.28	41.77	47.89
Natural Gas Liquids ($/bbl)					
Price	69.54	65.89	61.53	65.52	83.36
Royalties	1.42	1.52	1.55	1.13	1.45
Netback	68.12	64.37	59.98	64.39	81.91
Total Liquids ($/bbl)					
Price	65.79	60.13	65.35	63.92	74.28
Royalties	6.29	4.64	7.83	4.67	8.05
Transportation and blending	2.65	2.54	2.45	2.82	2.81
Operating	13.90	12.93	14.14	13.93	14.71
Production and mineral taxes	0.56	0.54	0.53	0.57	0.59
Netback	42.39	39.48	40.40	41.93	48.12
Total Natural Gas ($/Mcf)					
Price	2.42	2.97	2.30	1.92	2.50
Royalties	0.03	0.02	0.02	0.01	0.06
Transportation and blending	0.10	0.10	0.08	0.08	0.13
Operating	1.10	1.29	1.08	0.98	1.08
Production and mineral taxes	0.01	(0.01)	0.02	0.02	0.02
Netback	1.18	1.57	1.10	0.83	1.21
Total ($/BOE)					
Price	46.60	45.50	46.61	43.25	50.84
Royalties	4.00	3.08	5.02	2.84	5.00
Transportation and blending	1.88	1.86	1.74	1.90	2.00
Operating	11.18	11.12	11.35	10.75	11.46
Production and mineral taxes	0.38	0.33	0.38	0.40	0.40
Netback	29.16	29.11	28.12	27.36	31.98

Impact of Long-term Incentive Costs (Recovery) on Total Operating Costs – 2012	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.16	0.05	0.32	(0.17)	0.42

Impact of Realized Gain (Loss) on Risk Management – 2012	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	1.39	3.35	2.02	1.64	(1.67)
Natural Gas ($/Mcf)	1.14	0.89	1.24	1.39	1.03
Total ($/BOE)	3.42	4.05	3.98	4.27	1.44

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.

Cenovus also 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. 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 2014 and 2013:

Net Capital Investment

($ millions)	2014	2013
Capital Investment		
Oil Sands		
Foster Creek	796	797
Christina Lake	794	688
Total	1,590	1,485
Other Oil Sands	396	400
	1,986	1,885
Conventional		
Pelican Lake	246	463
Other Conventional	594	726
	840	1,189
Refining and Marketing	163	107
Corporate	62	81
Capital Investment	3,051	3,262
Acquisitions (1)	18	32
Divestitures	(277)	(283)
Net Acquisition and Divestiture Activity	(259)	(251)
Net Capital Investment (2)	2,792	3,011

(1) The 2014 acquisition capital includes the assumption of a decommissioning liability of $10 million.
(2) 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 Company 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 Company'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 Company's future planning, Management and the Board review the impact of a variety of carbon constrained scenarios on Cenovus's strategy, with a current price range from $15 to $65 per tonne of emissions applied across a range of regulatory policy options. A major benefit of applying a range of carbon prices at the strategic level is that it can provide direct guidance to the capital allocation process. Although uncertainty remains regarding potential future emissions regulation, the Company 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 Regulations".

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 developments both in Canada and the U.S.

Cenovus expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2014, 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 2015. Refer to "Risk Factors – Environment & Regulatory Risks – Environmental Regulations" for further information on environmental protection matters affecting Cenovus.

CORPORATE RESPONSIBILITY PRACTICE

Cenovus's operations are guided by a Corporate Responsibility ("CR") Policy that clearly outlines accountabilities for all staff, including its leadership and the vendors and suppliers who work with Cenovus. Cenovus's CR Policy was developed through an externally recognized process focused on engagement with employees, external stakeholders and industry experts. The CR Policy commits the Company to conduct its business in a responsible, transparent and respectful way while complying with all relevant and applicable laws, regulations and industry standards. Cenovus's CR Policy is available on the Company's website at cenovus.com.

Cenovus's CR Policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. Cenovus will continue to externally report on its performance in these areas through its annual CR report. Cenovus's annual CR report involves a limited assurance engagement with an independent auditor on a select number of quantitative indicators. This report is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program. The CR Policy emphasizes Cenovus's commitment to protect the health and safety of all individuals affected by its activities, including its workforce and the communities where it operates. Cenovus will strive to never compromise the health and safety of any individual in the conduct of its activities. Cenovus will strive to provide a safe and healthy work environment and the Company expects its workers to comply with the health and safety practices established for their protection. Additionally, the CR Policy includes reference to emergency response management, investment in efficiency projects, new technologies and research, and support of the principles of the Universal Declaration of Human Rights.

The CR Policy was introduced in tandem with the Cenovus Operating Management System in 2011. The Cenovus Operating Management System is closely aligned with the CR Policy. Current steps that the Company has in place to ensure the successful integration of the CR Policy include: (i) a security program to regularly assess security threats to business operations and to manage the associated risks; (ii) CR performance metrics to track Cenovus's progress; (iii) an energy efficiency program that focuses on reducing energy use at the Company's operations, supports initiatives at the community level and provides incentives for employees to reduce energy use in their homes; (iv) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Cenovus's policies or practices or other regulations; (v) an Integrity Helpline that provides an additional avenue for the Company's stakeholders to raise their concerns; (vi) the CR website which allows people to write to Cenovus about non-financial issues of concern; (vii) related policies and practices such as an Alcohol and Drug Policy, a Code of Business Conduct & Ethics, an Aboriginal Business Engagement Framework, and an Expect Respect program concerning local community relations; (viii) a formal planning process to align environmental actions with environment and business priorities so that the Company's programs and efforts are focused on the most important areas; and (ix) a requirement for acknowledgement and sign-off on key policies and practices by the Company's Board and employees. Cenovus's Board approved the CR Policy on recommendation of the Safety, Environment and Responsibility Committee. The Board is also advised of significant policy contraventions and receives updates on trends, issues or events which could impact Cenovus.

In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based international investment specialist in sustainability investing that publishes the Dow Jones Sustainability Index (see below). Corporate Knights magazine also named Cenovus to their 2014 Global 100 clean capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland. In February 2014, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the second year in a row.

In June 2014, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the third year in a row and for the fourth consecutive year by Corporate Knights magazine as one of the 2014 Best 50 Corporate Citizens in Canada. Cenovus was also included in the Euronext Vigeo World 120 Index. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development. In September 2014, the Company's leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the third consecutive year and to the Dow Jones Sustainability North America Index for the fifth consecutive year. The Dow Jones Sustainability Indices track the financial performance of the leading companies worldwide regarding CR performance. In December 2014, Cenovus was named to the Canada 200 Climate Disclosure Leadership Index for the fifth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions.

These external recognitions of the Company's commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

EMPLOYEES

The following table summarizes Cenovus's full-time equivalent ("FTE") employees as at December 31, 2014:

	FTE Employees
Oil Sands	1,315
Conventional	640
Refining and Marketing	86
Cenovus-wide	1,504
Total	3,545

Cenovus also engages a number of contractors and service providers. Refer to "Risk Factors – Operational Risks – Personnel" 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 Company'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 or More
Ralph S. Cunningham [2,4,5,7] Houston, Texas, United States	2009 Independent	Mr. Cunningham is Chairman of TETRA Technologies, Inc., a publicly traded energy services and chemicals company. Mr. Cunningham 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; as a director and President & Chief Executive Officer of EPE Holdings, LLC, the sole general partner of Enterprise GP Holdings L.P., a publicly traded midstream energy holding company from August 2007 to November 2010; as a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, L.P. from December 2005 to May 2010; as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., a publicly traded midstream energy limited partnership from December 2009 to November 2010; as a director of DEP Holdings, LLC, the sole general partner of Duncan Energy Partners L.P., a publicly traded midstream energy company from August 2007 to May 2010; and as a director of Agrium Inc., a publicly traded agricultural chemicals company from December 1996 to April 2013. He is also a member of the Auburn University Chemical Engineering Advisory Council and the Auburn University Engineering Advisory Council.
Patrick D. Daniel [2,3,4,5] Calgary, Alberta, Canada	2009 Independent	Mr. Daniel is a director of Canadian Imperial Bank of Commerce; 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 also a member of the Association of Professional Engineers and Geoscientists of Alberta and chairs a campaign for the Alberta Cancer Foundation to build a new cancer hospital in Calgary.

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years or More
Ian W. Delaney [2,4,5,7] Toronto, Ontario, Canada	2009 Independent	Mr. Delaney is Chairman of The Westaim Corporation, a publicly traded investment company. Mr. Delaney served as a director of Sherritt International Corporation, a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity from October 1995 to May 2013. During his tenure with Sherritt, he also served as Chairman from November 1995 to May 2004, Executive Chairman from May 2004 to December 2008, Chairman and Chief Executive Officer from January 2009 to December 2011 and Chairman from January 2012 to May 2013. Mr. Delaney also served as Chairman of UrtheCast Corp. (formerly Longford Energy Inc.), a publicly traded video technology development company, from August 2012 to October 2013 and as a director of Dacha Strategic Metals Inc., a publicly traded investment company focused on the acquisition, storage and trading of strategic metals from November 2012 to September 2014.
Brian C. Ferguson [8] Calgary, Alberta, Canada	2009	Mr. Ferguson became President & Chief Executive Officer when Cenovus was formed on November 30, 2009. Mr. Ferguson is responsible for the overall leadership of Cenovus's strategic and operational performance. Prior to leading Cenovus, Mr. Ferguson was Executive Vice-President & Chief Financial Officer of Encana. His business experience includes a variety of areas in finance, business development, reserves, strategic planning, evaluations and communications. Mr. Ferguson is a Fellow of the Institute of Chartered Accountants of Alberta, a member of the Canadian Association of Petroleum Producers (CAPP) and participates on several CAPP committees, including the Oil Sands CEO Council, a member of the Canadian Institute of Chartered Accountants (CICA), a director and a member of the Canadian Council of Chief Executives and Chair of the Calgary Police Foundation. He previously served as Chairman of CICA's Risk Oversight and Governance Board and on the board of CAPP, and is a former member of the Global Commerce Strategy Advisory Panel.
Michael A. Grandin [2,5,9] 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. He was Chairman and Chief Executive Officer of Fording Canadian Coal Trust, a publicly traded mining trust, from February 2003 to October 2008 when it was acquired by Teck Cominco Limited. He was President of PanCanadian Energy Corporation from October 2001 to April 2002 when it merged with Alberta Energy Company Ltd. to form Encana. Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006.
Valerie A.A. Nielsen [2,3,5,6] 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. She was also a member and past chair of an advisory group on the General Agreement on Tariffs and Trade (GATT) and the North America Free Trade Agreement (NAFTA) regarding international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. She is also a past director of the Bank of Canada and of the Canada Olympic Committee. Ms. Nielsen is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Exploration Geophysicists, and has been awarded the designation of Fellow of Geoscientists Canada (FGC).

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years or More
Charles M. Rampacek [5,6,7] 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. He serves on the Engineering Advisory Council for the University of Texas and the College of Engineering Leadership Board for the University of Alabama.
Colin Taylor [3,4,5] Toronto, Ontario, Canada	2009 Independent	Mr. Taylor served two consecutive four-year terms as Chief Executive & Managing Partner of Deloitte & Touche LLP and then acted as Senior Counsel until his retirement in May 2008. Mr. Taylor is also a member of the Canadian Institute of Chartered Accountants and Fellow of the Institute of Chartered Accountants of Ontario.
Wayne G. Thomson [2,5,6,7] 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; 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. 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) Former director of Encana.
(3) Member of the Audit Committee.
(4) Member of the Human Resources and Compensation Committee.
(5) Member of the Nominating and Corporate Governance Committee.
(6) Member of the Reserves Committee.
(7) Member of the Safety, Environment and Responsibility Committee.
(8) As an officer and a non-independent director, Mr. Ferguson is not a member of any of the committees of Cenovus's Board.
(9) 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, 2014.

Name and Residence	Office Held and Principal Occupation During the Past Five Years or More
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 became Executive Vice-President & Chief Financial Officer on November 30, 2009. In 2009, Mr. Ruste held the following positions with Encana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer; and Executive Vice-President & Chief Risk Officer.
John K. Brannan Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer Mr. Brannan became Executive Vice-President & Chief Operating Officer on December 1, 2010. From November 2009 to November 2010, Mr. Brannan was Cenovus's Executive Vice-President (President, Integrated Oil Division). In 2009, Mr. Brannan held the following position with Encana: Executive Vice-President (President, Integrated Oil Division).

Name and Residence	Office Held and Principal Occupation During the Past Five Years or More
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President, Oil Sands Mr. Chhina became Executive Vice-President, Oil Sands on December 1, 2010. From November 2009 to November 2010, Mr. Chhina was Cenovus's Executive Vice-President, Enhanced Oil Development & New Resource Plays. In 2009, Mr. Chhina held the following position with Encana: Vice-President, Upstream Operations, Integrated Oil Sands Division.
Kerry D. Dyte Calgary, Alberta, Canada	Executive Vice-President, General Counsel & Corporate Secretary Mr. Dyte became Executive Vice-President, General Counsel & Corporate Secretary on November 30, 2009. In 2009, Mr. Dyte held the following position with Encana: Vice-President, General Counsel & Corporate Secretary.
Sheila M. McIntosh Calgary, Alberta, Canada	Executive Vice-President, Environment & Corporate Affairs Ms. McIntosh became Executive Vice-President, Environment & Corporate Affairs on February 1, 2013. From November 2009 to January 2013, Ms. McIntosh was Cenovus's Executive Vice-President, Communications & Stakeholder Relations. In 2009, Ms. McIntosh held the following position with Encana: Executive Vice-President, Corporate Communications.
Robert W. Pease Calgary, Alberta, Canada	Executive Vice-President, Markets, Products & Transportation Mr. Pease became Executive Vice-President, Markets, Products & Transportation on June 2, 2014. 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 single 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 leading refiner, distributer and marketer of fuels in the eastern and Gulf Coast regions of the U.S.
Hayward J. Walls Calgary, Alberta, Canada	Executive Vice-President, Strategy & Organization Development Mr. Walls became Executive Vice-President, Strategy & Organization Development on February 12, 2014. From November 2009 to February 2014, Mr. Walls was Cenovus's Executive Vice-President, Organization & Workplace Development. In 2009, Mr. Walls held the following position with Encana: Executive Vice-President, Corporate Services.

As of December 31, 2014, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,146,716 common shares of Cenovus ("Common Shares") or approximately 0.15 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 Company'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 company 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 Company'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 Company'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.

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 three 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.

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 accountant, a member and Fellow of the Institute of Chartered Accountants of Ontario and a member of the Canadian Institute of Chartered Accountants. 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 & Touche 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 & Touche 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, 2014 and 2013:

($ thousands)	**2014**	2013
Audit Fees (1)	**2,597**	2,460
Audit-Related Fees (2)	**202**	342
Tax Fees (3)	**110**	374
All Other Fees (4)	**6**	3
Total	**2,915**	3,179

(1) Audit Fees consist of the aggregate fees billed for the audit of the Company'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 Company'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 tax compliance, tax advice and tax planning. The services provided in this category primarily included support of scientific research and experimental development claims for Cenovus and FCCL.

(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 an unlimited number of First Preferred Shares and Second Preferred Shares. As at December 31, 2014, there were approximately 757.1 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 Company'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 Company 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 Company's Board is restricted from issuing First Preferred Shares or Second Preferred Shares if by doing so the aggregate amount payable to holders of such class, as a return of capital in the event of liquidation, dissolution or winding up or any other distribution of assets among shareholders for the purpose of winding up, would exceed $500 million.

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 Company'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 amended and reconfirmed at the 2012 annual meeting of shareholders and must be reconfirmed by the Company's shareholders at every third annual shareholder meeting.

DIVIDEND REINVESTMENT PLAN

Cenovus has a dividend reinvestment plan, which permits holders of Common Shares to automatically reinvest all or any portion of the cash dividends paid on their Common Shares in additional Common Shares. At the discretion of the Company, the additional Common Shares may be issued from treasury at the average market price or purchased on the market.

On February 12, 2015, the Company announced that the additional Common Shares issued to participants under Cenovus's dividend reinvestment plan will be issued from treasury of the Company at a three percent discount to the average market price (as defined in the dividend reinvestment plan).

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 expire 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 Company'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 Company'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	A (Low)
Commercial Paper Short-Term Rating	A-1 (Low)	P-2	R-1 (Low)
Outlook/Trend	Negative	Stable	Stable

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

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB+ by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories. S&P's Canadian commercial paper ratings scale ranges from A-1(High) to D, which represents the range from highest to lowest quality. A rating of A-1(Low) is the third highest of eight categories and indicates that the obligor is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher categories but has satisfactory capacity to meet its financial commitments. A S&P rating outlook assesses the potential direction of a credit rating over the intermediate term. In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. A "Negative" outlook indicates that a rating may be lowered.

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 (i.e., they are subject to moderate credit risk). Such debt securities 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.

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 A(low) by DBRS is within the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for payment of financial obligations is substantial, but of lesser credit quality than that of higher rated securities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. 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-1(low) is the third highest of 10 categories and indicates that the short-term debt is of good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial but overall strength is not as favourable as higher rating categories. Cenovus may be vulnerable to future events but qualifying negative factors are considered manageable.

Throughout the last two years, Cenovus has made payments to S&P, Moody's, and DBRS related to the rating of the Company'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. The Board has approved a first quarter dividend of $0.2662 per share payable on March 31, 2015 to holders of Common Shares of record as of March 16, 2015. 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
2014	1.0648	0.2662	0.2662	0.2662	0.2662
2013	0.968	0.242	0.242	0.242	0.242
2012	0.880	0.220	0.220	0.220	0.220

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 2014:

	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	30.33	28.64	29.14	29,048	28.58	25.74	26.15	27,126
February	29.70	28.25	29.31	40,457	27.01	25.52	26.51	25,695
March	32.02	28.85	31.97	29,916	28.96	25.90	28.96	18,037
April	33.11	31.28	32.65	29,709	30.21	28.51	29.77	22,339
May	32.66	30.80	32.27	30,225	29.88	28.35	29.79	17,140
June	34.70	31.93	34.59	32,047	32.44	29.31	32.37	21,229
July	34.79	32.61	33.49	25,914	32.64	30.18	30.70	19,192
August	34.68	32.59	34.68	22,364	31.89	29.81	31.89	18,265
September	34.70	29.77	30.13	38,787	31.80	26.57	26.88	23,205
October	30.13	25.79	27.89	69,010	26.89	22.75	24.76	50,631
November	29.11	25.10	25.67	37,865	25.74	22.01	22.10	31,424
December	26.61	18.72	23.97	71,704	23.42	16.11	20.62	72,417

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 Company's operations. Cenovus has identified risks in four main categories: financial, operational, environment & regulatory, and reputation. The impact of any risk or a combination of risks in these four categories may adversely affect the Company'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 Company'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 Company'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 financial and credit markets; development and operating costs; availability of credit and access to sufficient liquidity; fluctuations in foreign exchange and interest rates; risks related to Cenovus's hedging activities; and risks related to the Company's ability to pay a dividend to shareholders. Changes in global economic conditions could impact a number of factors including, but not limited to, pace of Cenovus's growth, financial strength of the Company's counterparties, access to capital and cost of borrowing.

Commodity Price Volatility

The Company'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; global 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 Company'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 Company'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 Company's business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact the value of Cenovus's assets, the Company'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 Company'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 Company'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 hedge the price risk of the Company's crude oil and natural gas production, as well as refining margins. Cenovus also uses derivative instruments in various operational markets to optimize its supply cost or sales. The Company may also utilize derivative instruments when considered appropriate, to help mitigate the potential impact of changes in interest rates and foreign exchange rates.

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

Additionally, 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 Company 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 Company 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 Company'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 Company'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, 2014, Cenovus had US$4.75 billion in debt outstanding with no principal payments due until October 2019 (US$1.3 billion). The Company has a $3.0 billion committed credit facility, with a maturity of November 30, 2018, of which the entire amount was available at December 31, 2014, to meet operating and capital requirements. Going forward, an inability to access the credit 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 could negatively impact the Company'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 Company 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 Company's ability to make capital investments, continue its business plan, meet all of its financial obligations as they come due and maintain existing properties may be impaired.

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 set in U.S. dollars, while many of the Company's operating and capital costs as well as its Consolidated Financial Statements are denominated in Canadian dollars. Cenovus also holds substantial amounts of U.S. dollar 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 Company'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. The fluctuations in exchange rates could have a material adverse effect on the Company's business, financial condition and cash flow.

Interest Rates

The Company 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 Company 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 Company'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 Company'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 Company's operational risks include, but are not limited to: operational and safety considerations; transportation constraints and interruptions; phased growth execution; uncertainty of reserves and resources estimates; reservoir performance and technical challenges; partner risks; competition; technology; third-party claims; land claims; key personnel; and information systems.

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; gaseous leaks; migration of harmful substances; oil spills; corrosion; and acts of vandalism and terrorism. Any of these hazards can interrupt operations, impact the Company'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.

Transportation Capacity and Pipeline 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, could adversely affect the Company'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 can 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 pipelines which would result in extra long-term take-away 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 also no certainty that crude-by-rail transportation and other alternative types of transportation for the Company's production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, Cenovus's crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact its crude oil sales volumes or the price received for its product. The Company's product or railcars may be involved in a derailment or incident that results in legal liability or reputational harm. In addition, if new regulation is introduced, including but not limited to the potential amendment of the safety standards for tank cars used to transport crude oil or if the liability regime is adjusted, it could adversely affect Cenovus's ability to ship crude oil by rail or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of the Company's refinery customers may limit Cenovus's ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

The Company'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 Company'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 Company 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 Company's control. In general, estimates of economically recoverable 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 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 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, 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 Company 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.

Uncertainty of Contingent and Prospective Resource Estimates

The contingent resources and prospective resources results included in this AIF are estimates only. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent and prospective resources. In addition, there are contingencies that prevent resources from being classified as reserves. There is no certainty 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. For additional information on resources and their associated contingencies, see "Contingent and Prospective Resources" in this AIF.

Project Execution

There are certain risks associated with the execution of both the Company's upstream and refining 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 Company's existing asset base could cause delays in achieving targets and objectives.

Partner Risks

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

Interests in certain of the Company's upstream assets are held in a partnership with ConocoPhillips, an unrelated U.S. public company, and are operated by Cenovus. The Company'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 Company 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 Company'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 Company'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 Company 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.

Several companies have announced 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 Company'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 Company 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 Company 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. Certain aboriginal groups have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including certain lands in Christina Lake. Such claims, if successful, could have an adverse effect on operations in the 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.

Personnel

Cenovus's success is dependent upon its Management, its leadership capabilities and the quality of its personnel. Failure to retain current personnel or to attract and retain new personnel with the necessary leadership traits, skills and competencies could have a material adverse effect on the Company's growth and profitability.

Information Systems

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

ENVIRONMENTAL & REGULATORY RISKS

Cenovus's industry is generally 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 GHG and other emissions; the export of crude oil, natural gas and other products; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development and abandonment of fields (including restrictions on production); and possibly expropriation or cancellation of contract rights.

Regulatory Approvals

All of the Company's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and refineries and the operation and abandonment of fields. Contract rights can be cancelled or expropriated in certain circumstances. Changes to government regulation could impact Cenovus's existing and planned projects.

Cenovus's operations require the Company 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 Company'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 Company'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. An increase in the royalty or mineral tax rates applicable in one or both provinces would reduce the Company's earnings and could make, in the respective province, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of Cenovus's associated assets.

Tax Laws

Income tax laws, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects Cenovus and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which the Company 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 Company'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 require that wells, facility sites, refineries and other properties associated with the Company's operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. 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. Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties and failure to comply with environmental regulations may result in the imposition of fines and penalties and the imposition of environmental protection orders. Although it is not expected that the costs of complying with environmental regulation will have a material adverse effect on Cenovus's financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. 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.

Climate Change Regulations

The Canadian federal government, various provincial governments and U.S. federal and state governments have announced intentions to regulate GHG emissions and other air pollutants (collectively, "regulations"). 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 Company's suppliers and service providers.

Adverse impacts to Cenovus's business if comprehensive GHG legislation or regulation is enacted and applies to the Company's business in any jurisdiction in which it operates or conducts business, 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 Company'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 of these additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Low Carbon Fuel Standards

Existing and proposed environmental legislation 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 Company 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 will be required to comply with the legislation. A number of studies produced on the subject, including one that was conducted by an organization that advised on the legislation, suggest a wide range of carbon intensity values for oil sands crudes. This could make it challenging for refiners to distinguish between crude oils and may negatively impact the Company's ability to market and sell its crude in this market.

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 Company'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 Company'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 its Lower Athabasca Regional Plan ("LARP"), which was issued under the ALSA. The LARP identifies 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 Company'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 its 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 its North Saskatchewan Regional Plan ("NSRP"). This plan will apply to Cenovus's operations in central Alberta. The first phase of public consultation for the NSRP is complete. No assurance can be given that the NSRP won't materially impact operations or future operations in this region.

Species at Risk Act

The 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 Company'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 Company's non-utility boilers, heaters and reciprocating engines will be regulated in accordance with specified performance standards. Regulations are expected to come into force on June 1, 2015. Cenovus does not anticipate a material impact to existing or future operations.

Water Licenses

Cenovus currently utilizes fresh water in certain operations, which is obtained under licenses issued pursuant to the *Water Act* to provide, for example, domestic and utility water at the Company's SAGD facilities and for its bitumen delineation programs. 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 Company'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. This new policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, where the Company's ten year wetlands mitigation and monitoring plans were recently approved under the 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 classification system and compensation requirements are still to be determined within the policy. While Cenovus does not anticipate a material impact, 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 Company 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. The increasing use of social media has especially heightened the need for reputational risk management.

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 Company'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 Company 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 Company's most recent Management's Discussion and Analysis, available at www.sedar.com, www.sec.gov and cenovus.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2014, 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, 2014, 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 Company 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 Company'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 Company 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, 2014, 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 Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 11, 2015 in respect of Cenovus's Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2014, December 31, 2013 and January 1, 2013 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2014, 2013, and 2012 and Cenovus's internal control over financial reporting as at December 31, 2014. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Information relating to reserves and resources 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 Company'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 www.sedar.com, and EDGAR at www.sec.gov. Additional financial information is contained in the Company's audited Consolidated Financial Statements and MD&A for the year ended December 31, 2014. 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 Company's management proxy circular for its most recent annual meeting of shareholders.

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, 2014, 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 Company 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, 2014 unless otherwise indicated. Numbers presented are rounded to the nearest whole number and tables may not add due to rounding.

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

ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

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

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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. 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 by us for the year ended December 31, 2014.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	Cenovus Energy Inc. Evaluation of a Portion of the Canadian Oil & Gas Reserves January 12, 2015	Canada	29,473
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation January 9, 2015	Canada	2,050
			31,523

5. 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. 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:

(signed) *"P.A. Welch"*

McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) *"Keith Braaten"*

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 10, 2015

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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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 has approved:

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

(signed)

Brian C. Ferguson
President & Chief Executive Officer

(signed)

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

(signed)

Michael A. Grandin
Director and Chair of the Board

(signed)

Wayne G. Thomson
Director and Chair of the Reserves Committee

February 11, 2015

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.

500 Centre Street SE
PO Box 766
Calgary, AB T2P 0M5

Our Annual Report is available on our website at cenovus.com

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2014

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 11, 2015, should be read in conjunction with our December 31, 2014 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 11, 2015, 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 11, 2015. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.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, 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 trading on the Toronto and New York stock exchanges. On December 31, 2014, we had a market capitalization of approximately $18 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in 2014 was approximately 203,500 barrels per day and our average natural gas production was 488 MMcf per day. Our refineries processed an average of 423,000 gross barrels per day of crude oil feedstock into an average of 445,000 gross barrels per day of refined products.

Our Key Message for 2014

Up until the fourth quarter, 2014 could be described as a period of relative financial stability. Commodity prices were relatively strong and were expected to remain so, and our financial results for the first nine months reflected this. At the onset of the fourth quarter, there was a substantial decline in the commodity price environment, which significantly impacted our fourth quarter financial results. Between September 30, 2014 and December 31, 2014, crude oil and refined product benchmark prices fell between 40 and 55 percent and the forward prices for 2015 show little sign of near-term improvement. Although declining commodity prices negatively impacted our 2014 results, we continued to make operational progress as shown by our growing crude oil production.

2015 will be a challenging time for our industry. However, Cenovus remains well positioned to manage through these volatile times. We have significantly reduced our 2015 capital budget to exercise further capital restraint in this low crude oil price environment. For more information we direct our readers to review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

Our Strategy

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a sustainable dividend. Inherent to our strategy is a focus on protecting our financial resilience by evaluating on a regular basis our capital investment plans, dividend plans and other relevant factors.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- 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; and
- Refining to help reduce the impact of commodity price fluctuations.

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. Our normal development planning is to evaluate these resources through stratigraphic test well drilling programs.

We anticipate increasing our annual net crude oil production, including our conventional crude oil operations, to more than 500,000 barrels per day by fully developing our producing projects and those that currently have regulatory approval.

Execution Excellence

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, allowing 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

We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. This is a significant reduction from 2014 levels in response to the current low crude oil price environment. A portion of our capital investment is expected to be internally funded through cash flow generated from our crude oil, natural gas and refining operations. The remainder is expected to be funded by prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

Dividend

The declaration of dividends is at the sole discretion of our Board and is considered each quarter. We paid dividends of $1.0648 per share in 2014 (2013 – $0.968 per share; 2012 – $0.88 per share).

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment continue to play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, potentially reducing costs and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches. 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:

	2014 Ownership Interest (percent)	2014 Net Production Volumes (bbls/d)	2014 Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	59,172	118,344
Christina Lake	50	69,023	138,046
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. Narrows Lake is under 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, respectively.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable 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.

	2014	
($ millions)	Crude Oil [1]	Natural Gas
Operating Cash Flow	1,360	508
Capital Investment	812	28
Operating Cash Flow Net of Related Capital Investment	548	480

(1) *Includes NGLs.*

We have established crude oil and natural gas producing assets, including a carbon dioxide enhanced oil recovery project in Weyburn Saskatchewan, as well as heavy oil assets at Pelican Lake and developing tight oil assets, located in Alberta.

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. About 50 percent of our total conventional production comes from our fee lands. We do not pay third-party royalties where we have working interest production from fee lands. Rather, we pay mineral tax to the government that is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties which may give rise to royalty income. This leased land resulted in Operating Cash Flow of approximately $150 million in 2014.

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.

	Ownership Interest (percent)	2014 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 differential fluctuations. This segment also includes our 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)	2014
Operating Cash Flow	**211**
Capital Investment	**163**
Operating Cash Flow Net of Related Capital Investment	**48**

2014 OPERATING AND FINANCIAL HIGHLIGHTS

In general, integration of our business provides some protection from commodity price fluctuations. In a period when crude oil price differentials widen and Operating Cash Flow from our upstream operations decreases, our refining operations benefit from lower heavy crude oil feedstock costs. In 2014, we experienced strong commodity prices for the first nine months which very quickly changed as crude oil and refined product benchmark prices fell between 40 and 55 percent from September 30, 2014 to December 31, 2014. The significant decline in prices had a significant negative impact on our fourth quarter financial results, including the valuation of our crude oil and refined product inventories and negatively impacted our full year financial results.

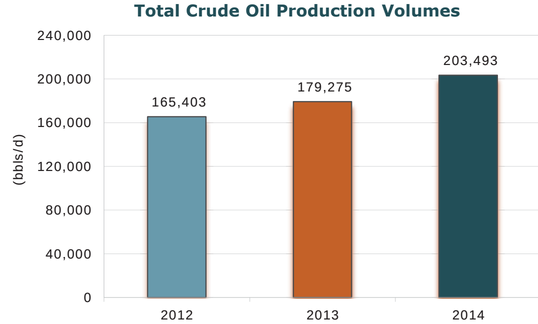
In 2014, other significant developments include increasing our crude oil production by 14 percent, growing our reserves, receiving regulatory approval for Grand Rapids and Telephone Lake, completing our planned capital program and increasing our market access capability through rail and pipeline commitments.

Operational Results

Total crude oil production averaged 203,493 barrels per day, up 14 percent from 2013.

Crude oil production from our Oil Sands segment averaged 128,195 barrels per day, an increase of 25 percent, primarily driven by a 40 percent increase in production at Christina Lake. Average production at Christina Lake increased to 69,023 barrels per day due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower steam to oil ratio ("SOR"). Phase E increased nameplate production capacity to 138,000 gross barrels per day.

Total Crude Oil Production Volumes



Foster Creek production averaged 59,172 barrels per day, up 11 percent due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. We also achieved first production from phase F in September, with ramp up expected to take approximately eighteen months. Phase F is our eleventh oil sands expansion phase.

Our Conventional crude oil production averaged 75,298 barrels per day, a slight decrease from 2013. An increase in production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was offset by expected natural declines and the impact of divestitures of non-core assets, including the sale of our Lower Shaunavon asset in the second half of 2013 and certain of our Bakken and Wainwright assets in 2014. The annual average crude oil production from these non-core assets was 2,173 barrels per day in 2014 (2013 – 5,223 barrels per day).

Our proved bitumen reserves increased seven percent to approximately 2.0 billion barrels and our proved plus probable bitumen reserves rose 30 percent to 3.3 billion barrels. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

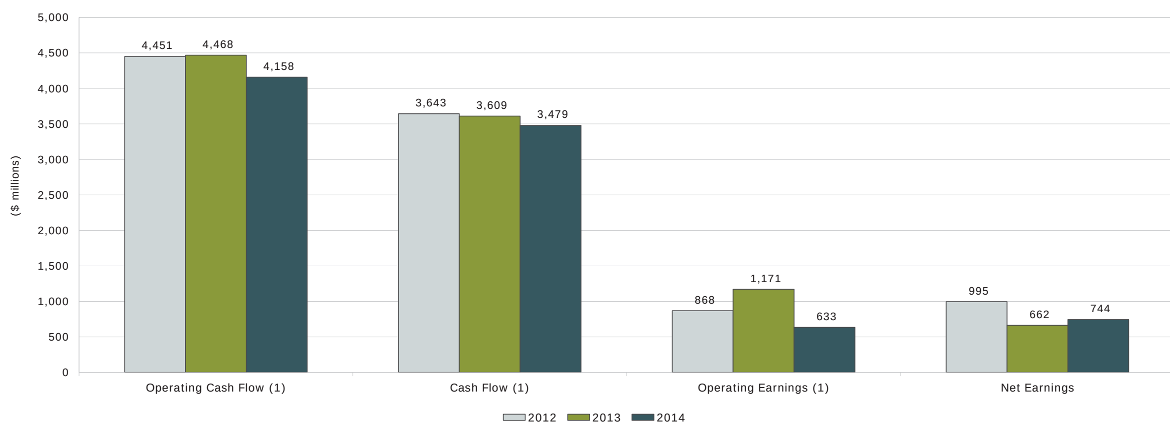
Crude oil processed and refined product output declined compared with 2013 primarily due to an unplanned coker outage at our Borger refinery and a planned turnaround at Wood River. We processed an average of 423,000 gross barrels per day (2013 – 442,000 gross barrels per day) of crude oil, of which 199,000 gross barrels per day (2013 – 222,000 gross barrels per day) was heavy crude oil. We produced 445,000 gross barrels per day of refined products, a decrease of 18,000 gross barrels per day, or four percent.

Other significant operational results in 2014 compared with 2013 include:

- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake. These approvals bring our expected production capacity on our producing properties and on projects with regulatory approval to over 500,000 net barrels per day;
- Receiving regulatory approval for expansion of the Foster Creek development area;
- The disposition of certain Bakken and Wainwright assets for net proceeds of approximately $269 million;
- Increasing rail takeaway capacity for crude oil to approximately 30,000 barrels per day at year end. In 2014, we transported an average of 10,000 barrels per day of crude oil by rail, including 47 unit train shipments; and
- Committing to additional pipeline transportation agreements to ensure adequate shipping capacity for our growing production.

Financial Results

Operating Cash Flow, Cash Flow, Operating Earnings and Net Earnings



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

Financial highlights for 2014 compared with 2013 include:

Revenues

Revenues of $19,642 million, an increase of $985 million or five percent, as a result of:

- Our average crude oil and natural gas sales prices (excluding financial hedging) rising six percent to $71.35 per barrel and 37 percent to $4.37 per Mcf, respectively;
- Crude oil sales volumes increasing 12 percent; and
- A rise in condensate volumes used in blending, consistent with the increase in production.

These increases to revenues were partially offset by:

- A decrease in revenues from our refining operations primarily due to lower refined product prices and declines in refined product output, partially offset by the weakening of the Canadian dollar;
- Higher royalties primarily due to an increase in crude oil sales prices and volumes; and
- Expected declines in natural gas production volumes.

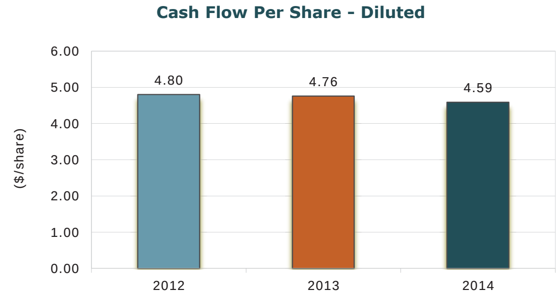
Operating Cash Flow

Operating Cash Flow of $4,158 million declined seven percent from 2013 primarily due to an 82 percent decrease in Operating Cash Flow from our Refining and Marketing segment. The decrease was due to lower average market crack spreads, higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price, higher operating expenses and a decrease in refined product output related to the planned and unplanned outages, and an inventory write-down of $113 million. Generally, when crude oil price differentials are widening, our refining Operating Cash Flow increases. However, with the sharp decline in prices during the fourth quarter, the cost of heavy crude oil feedstock processed was higher than the refined product pricing we realized.

The decrease in Operating Cash Flow from our Refining and Marketing segment was partially offset by a 19 percent increase in upstream Operating Cash Flow to $3,947 million. The increase was primarily due to higher average crude oil and natural gas sales prices and a rise in crude oil sales volumes, partially offset by higher royalties, an increase in operating expenses and an inventory write-down of $18 million.

Cash Flow

Cash Flow decreased four percent to $3,479 million. Cash Flow was lower primarily due to a decline in Operating Cash Flow as discussed above and a decrease in interest income, partially offset by a decline in finance costs, lower current income tax and the absence of a pre-exploration expense in 2014 compared with 2013.



Operating Earnings

Operating Earnings decreased $538 million, or 46 percent, primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million due to declines in crude oil prices and a slowing down of the Pelican Lake development plan;
- Inventory write-downs of $131 million discussed above in Operating Cash Flow due to a decline in prices;
- Exploration expense of $86 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible; and
- Property, plant and equipment ("PP&E") impairment of $65 million primarily related to impaired equipment.

Other significant non-cash items impacting Operating Earnings include higher depreciation, depletion and amortization ("DD&A") and lower deferred income taxes.

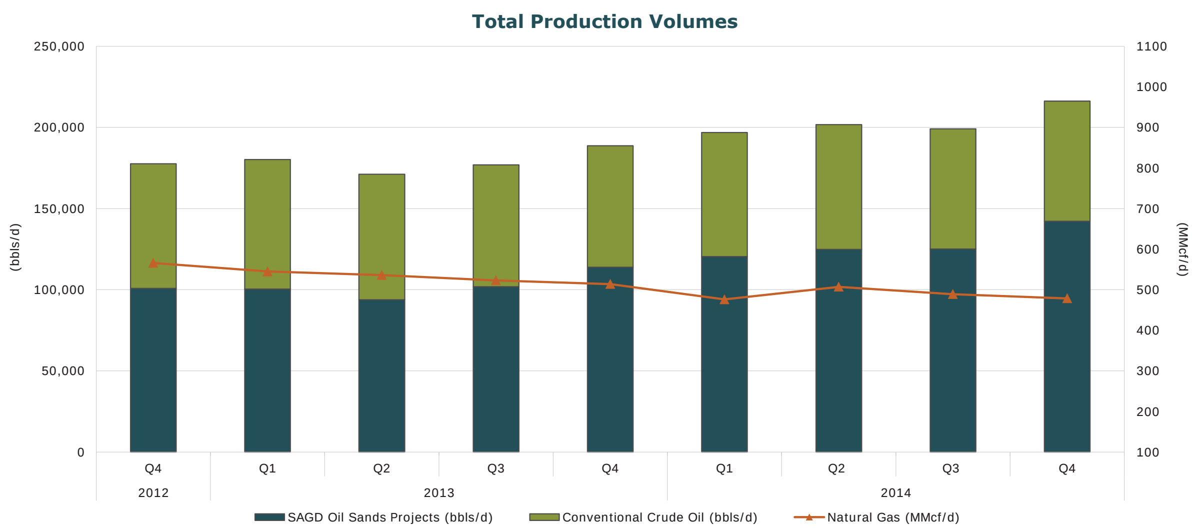
Net Earnings

Net Earnings increased $82 million, or 12 percent, to $744 million. The lower Operating Earnings discussed above was more than offset by unrealized risk management gains compared with losses in 2013, gains on the sale of non-core assets and a foreign exchange loss realized in 2013 related to the Partnership Contribution Receivable. The increase to Net Earnings was partially offset by higher non-operating unrealized foreign exchange losses.

Capital Investment

Capital investment was $3,051 million, a decrease of six percent. Capital investment in our Conventional segment declined primarily at Pelican Lake reflecting our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program, partially offset by the increase in capital investment at Christina Lake.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	2014	Percent Change	2013	Percent Change	2012
Oil Sands					
Foster Creek	**59,172**	**11%**	53,190	(8)%	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736
Conventional					
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9)%**	15,991	- %	16,015
Total Heavy Oil	**39,546**	**(2)%**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3)%**	35,467	(2)%	36,071
NGLs (1)	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2)%**	76,775	1%	75,667
Total Crude Oil Production	**203,493**	**14%**	179,275	8%	165,403

(1) NGLs include condensate volumes.

Production from Christina Lake increased significantly in 2014 due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower SOR. Our 2014 planned turnaround at phases A and B was successfully completed in the second quarter with minimal impact to production as volumes during that time were processed through the phase C, D and E plant.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. In September, we achieved first production from phase F, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

In total, our Conventional crude oil production decreased slightly in 2014. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Pelican Lake production was higher due to an increased response from the polymer flood program and additional infill wells coming on stream, partially offset by a planned turnaround.

Natural Gas Production Volumes

(MMcf per day)	2014	2013	2012
Conventional	**466**	508	564
Oil Sands	**22**	21	30
	488	529	594

In 2014, our natural gas production declined as expected. We continued to focus natural gas capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Operating Netbacks

	Crude Oil (1) ($/bbl)			Natural Gas ($/Mcf)		
	2014	2013	2012	**2014**	2013	2012
Price (2)	**71.35**	67.01	65.79	**4.37**	3.20	2.42
Royalties	**6.18**	5.01	6.29	**0.08**	0.04	0.03
Transportation and Blending (2) (3)	**2.98**	3.12	2.65	**0.12**	0.11	0.10
Operating Expenses	**15.59**	15.65	13.90	**1.23**	1.16	1.10
Production and Mineral Taxes	**0.50**	0.48	0.56	**0.05**	0.02	0.01
Netback Excluding Realized Risk Management	**46.10**	42.75	42.39	**2.89**	1.87	1.18
Realized Risk Management Gain (Loss)	**0.50**	1.09	1.39	**0.04**	0.32	1.14
Netback Including Realized Risk Management	**46.60**	43.84	43.78	**2.93**	2.19	2.32

(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 $30.49 per barrel (2013 – $28.33 per barrel; 2012 – $26.72 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 or 2012. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.

In 2014, our average crude oil netback, excluding realized risk management gains and losses, increased $3.35 per barrel primarily due to higher sales prices, consistent with the rise in the Western Canadian Select ("WCS") and Christina Dilbit Blend ("CDB") benchmark prices and the weakening of the Canadian dollar. The weakening of the

Canadian dollar in 2014 had a positive impact on our crude oil price of approximately $5 per barrel using the foreign exchange rate at December 31, 2014. Our average natural gas netback, excluding realized risk management gains and losses, increased $1.02 per Mcf primarily due to higher sales prices consistent with the rise in the AECO benchmark price.

Refining [1]

	2014	Percent Change	2013	Percent Change	2012
Crude Oil Runs (Mbbls/d)	**423**	**(4)%**	442	7%	412
Heavy Crude Oil	**199**	**(10)%**	222	12%	198
Refined Product (Mbbls/d)	**445**	**(4)%**	463	7%	433
Crude Utilization (percent)	**92**	**(5)%**	97	6%	91

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

In 2014, crude oil runs and refined product output declined as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however, to a lesser extent.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics 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 2014	Q4 2013	2014	2013	2012
Crude Oil Prices (US$/bbl)					
Brent					
Average	**76.98**	109.35	**99.51**	108.76	111.70
End of Period	**57.33**	110.80	**57.33**	110.80	111.11
WTI					
Average	**73.15**	97.46	**93.00**	97.97	94.20
End of Period	**53.27**	98.42	**53.27**	98.42	91.82
Average Differential Brent-WTI	**3.83**	11.89	**6.51**	10.79	17.50
WCS [2]					
Average	**58.91**	65.26	**73.60**	72.77	73.17
End of Period	**37.59**	74.80	**37.59**	74.80	59.16
Average Differential WTI-WCS	**14.24**	32.20	**19.40**	25.20	21.03
Condensate (C5 @ Edmonton)					
Average	**70.57**	94.22	**92.95**	101.69	100.93
Average Differential WTI-Condensate (Premium)/Discount	**2.58**	3.24	**0.05**	(3.72)	(6.73)
Average Differential WCS-Condensate (Premium)/Discount	**(11.66)**	(28.96)	**(19.35)**	(28.92)	(27.76)
Average Refined Product Prices (US$/bbl)					
Chicago Regular Unleaded Gasoline (“RUL”)	**81.26**	103.52	**107.40**	116.35	119.58
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**101.48**	121.98	**117.55**	126.31	126.58
Refining Margin 3-2-1 Average Crack Spreads (US$/bbl)					
Chicago	**14.60**	12.29	**17.61**	21.77	27.76
Group 3	**13.28**	10.66	**16.27**	20.80	28.56
Natural Gas Average Prices					
AECO (C$/Mcf)	**4.01**	3.15	**4.42**	3.17	2.41
NYMEX (US$/Mcf)	**4.00**	3.60	**4.42**	3.65	2.79
Basis Differential NYMEX-AECO (US$/Mcf)	**0.44**	0.59	**0.40**	0.58	0.38
Foreign Exchange Rates (US$ per C$1)					
Average	**0.881**	0.953	**0.905**	0.971	1.001

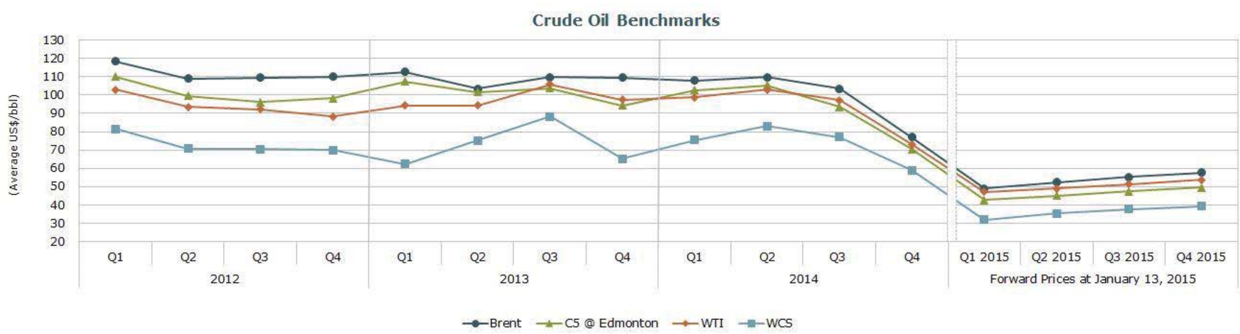
(1) *These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.*

(2) *The Canadian dollar average WCS benchmark price for 2014 was $81.33 per barrel (2013 – $74.94 per barrel; 2012 – $73.10 per barrel), fourth quarter average WCS benchmark price was $66.87 per barrel (Q4 2013 – $68.48 per barrel).*

Crude Oil Benchmarks

In the fourth quarter of 2014, there was a significant decrease in crude oil and refining benchmark prices. The end of period Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. In addition, average end of period refined product prices and 3-2-1 market crack spreads declined 47 percent and 87 percent at December 31, 2014 compared with September 30, 2014.

In the fourth quarter of 2014, the declines were primarily due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply and the unexpected return of Libyan crude oil supply. In addition, the Organization of Petroleum Exporting Countries ("OPEC") decided to maintain its level of crude oil output. The OPEC decision signals a desire to protect market share as opposed to maintaining price stability. We anticipate continued volatility in crude oil prices and expect prices to remain relatively low in 2015 as shown below. Refer to the Outlook section of this MD&A for our outlook on commodity prices over the next twelve months.



The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In 2014, the average price of Brent crude oil decreased by US$9.25 per barrel (nine percent). In the third quarter of 2014, Brent crude oil prices started to decline due to slowing global economic conditions outside of the U.S. slowing crude oil demand and strong growth in North American crude oil supply creating a global imbalance of supply and demand. In the fourth quarter of 2014, the imbalance was furthered with the decision made by OPEC to maintain their level of crude oil output resulting in the continued decline of Brent crude oil prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The WTI-Brent average differential narrowed in 2014 by US$4.28 per barrel (40 percent) as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved severe congestion that developed in the first half of 2013.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential narrowed by US$5.80 per barrel (23 percent) primarily due to capacity additions on existing pipelines as well as improved performance across the pipeline network used to export crude oil to U.S. refineries. Growing rail capacity helped to relieve congestion by providing access to existing and new U.S. heavy oil refining markets. In addition, heavy oil demand increased as new coker capacity in the Chicago area came online earlier this year and continues to ramp up.

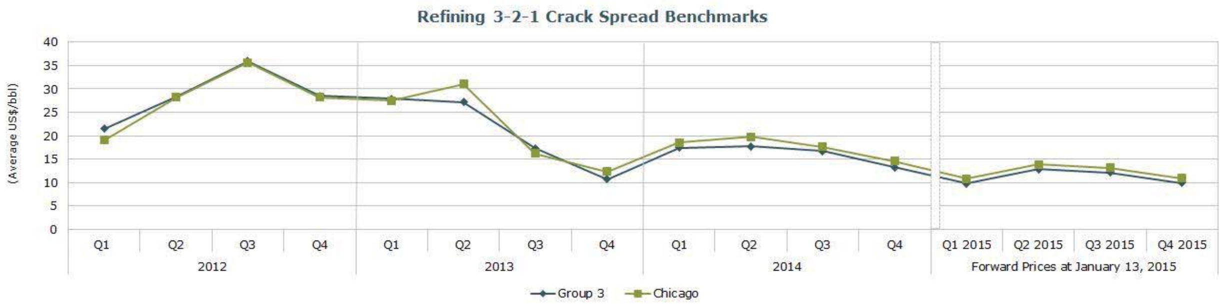
Blending condensate with bitumen and heavy oil enables our production to be transported though pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Compared with 2013, the WTI-Condensate average differential narrowed by US$3.77 per barrel as new pipeline capacity from the U.S. Gulf Coast to western Canada decreased the cost of importing condensate. The WCS-Condensate average differential narrowed by US$9.57 per barrel primarily due to improved transportation infrastructure for both condensate imports into Alberta and heavy crude oil exports to market.

Refining Benchmarks

The Chicago RUL and Chicago 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 inland refined product prices decreased in 2014 due to weaker global crude oil pricing. Average inland market crack spreads fell compared with 2013 due to the narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, 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.



Other Benchmarks

Average natural gas prices increased in 2014 due to an abnormally cold winter leading to large draws of natural gas from storage and the subsequent need for larger than normal injections of natural gas to refill storage.

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars, and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. In 2014, the Canadian dollar weakened by $0.07 relative to the U.S. dollar due to weaker commodity prices and interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved. The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $1.5 billion on our revenues using the foreign exchange rate at December 31, 2014.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance measures are discussed in more detail within this section.

($ millions, except per share amounts)	**2014**	**Percent Change**	2013	Percent Change	2012
Revenues	**19,642**	**5%**	18,657	11%	16,842
Operating Cash Flow (1)	**4,158**	**(7)%**	4,468	- %	4,451
Cash Flow (1)	**3,479**	**(4)%**	3,609	(1)%	3,643
Per Share – Diluted	**4.59**	**(4)%**	4.76	(1)%	4.80
Operating Earnings (1)	**633**	**(46)%**	1,171	35%	868
Per Share – Diluted	**0.84**	**(46)%**	1.55	36%	1.14
Net Earnings	**744**	**12%**	662	(33)%	995
Per Share – Basic	**0.98**	**11%**	0.88	(33)%	1.32
Per Share – Diluted	**0.98**	**13%**	0.87	(34)%	1.31
Total Assets	**24,695**	**(2)%**	25,224	4%	24,216
Total Long-Term Financial Liabilities (2)	**5,484**	**(10)%**	6,113	- %	6,128
Capital Investment (3)	**3,051**	**(6)%**	3,262	(3)%	3,368
Cash Dividends	**805**	**10%**	732	10%	665
Per Share	**1.0648**	**10%**	0.968	10%	0.88

(1) Non-GAAP measure defined in this MD&A.
(2) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(3) Includes expenditures on PP&E and Exploration and Evaluation ("E&E") assets.

Revenues

During 2014, revenues increased $985 million or five percent compared with 2013 primarily related to an increase in upstream revenues, which include the Oil Sands and Conventional segments.

($ millions)	**2014 vs. 2013**	2013 vs. 2012
Revenues, Comparative Year	**18,657**	16,842
Increase (Decrease) due to:		
Oil Sands	**1,020**	610
Conventional	**220**	177
Refining and Marketing	**(48)**	1,350
Corporate and Eliminations	**(207)**	(322)
Revenues, End of Year	**19,642**	18,657

Upstream revenues rose in 2014 by 19 percent primarily due to higher blended crude oil sales volumes and rising sales prices for blended crude oil and natural gas, partially offset by an increase in royalties.

Revenues generated by our Refining and Marketing segment decreased slightly as a 19 percent increase in revenues from our marketing operations was offset by a five percent decline from our refining operations. Revenues from third-party sales undertaken by the marketing group increased primarily due to higher purchased crude oil and natural gas volumes and an increase in natural gas sales prices. Refining revenues decreased due to a decline in refined product pricing consistent with lower Chicago RUL and Chicago ULSD benchmark prices and lower refined product output, partially offset by the weakening of the Canadian dollar.

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

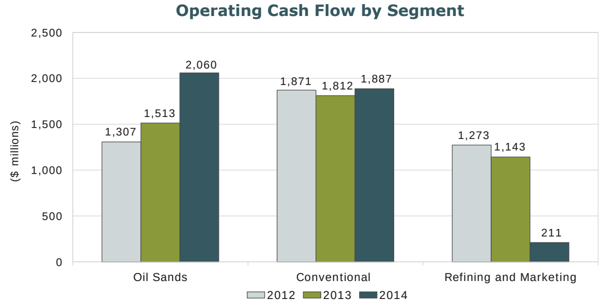
Revenues increased in 2013 compared with 2012 primarily in our refining operations. The increases were due to higher refined product output and a weakening of the Canadian dollar. In our upstream operations, revenues increased due to higher blended crude oil sales volumes and an increase in sales prices for natural gas and blended crude oil.

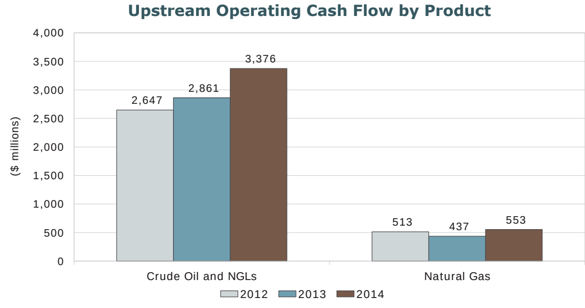
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Cash Flow

Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. 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)	**2014**	2013	2012
Revenues	**20,454**	19,262	17,125
(Add) Deduct:			
Purchased Product	**11,767**	11,004	9,506
Transportation and Blending	**2,477**	2,074	1,798
Operating Expenses	**2,072**	1,803	1,669
Production and Mineral Taxes	**46**	35	37
Realized (Gain) Loss on Risk Management Activities	**(66)**	(122)	(336)
Operating Cash Flow	**4,158**	4,468	4,451





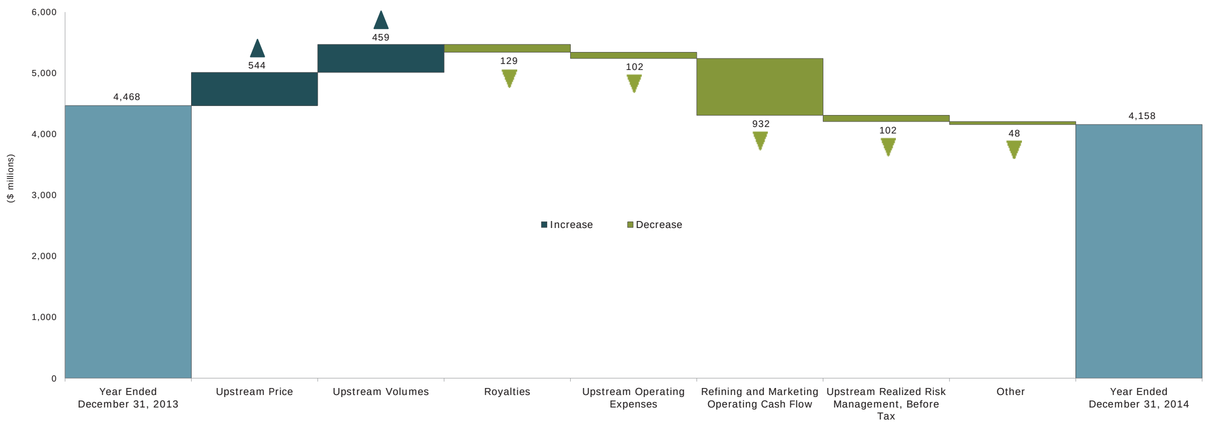
Total Operating Cash Flow in 2014 was $4,158 million, a decline of seven percent from 2013. As highlighted in the graph below, our Operating Cash Flow decreased $310 million compared with 2013 primarily due to:

- A decline in Operating Cash Flow from Refining and Marketing as a result of a decrease in average market crack spreads, higher heavy crude oil feedstock costs relative to WTI, increased operating expenses, an inventory write-down and lower refined product output. Refining and Marketing Operating Cash Flow was also impacted by the steep decline in prices in the fourth quarter due to a time lag between the purchase of crude oil feedstock at low prices and the processing through our refineries, and our valuation of feedstock costs on a FIFO accounting basis;
- Higher royalties due to an increase in crude oil sales prices and volumes;
- An increase in crude oil operating expenses, partially due to higher crude oil production. On a per barrel basis, crude oil operating expenses decreased by $0.06 to $15.59 per barrel; and
- Realized risk management gains before tax, excluding Refining and Marketing, of $39 million compared with gains of $141 million in 2013.

The decreases were partially offset by:

- A six percent increase in our average crude oil sales price to $71.35 per barrel and a 37 percent increase in our average natural gas sales price to $4.37 per Mcf; and
- A 12 percent increase in our crude oil sales volumes.

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)	**2014**	2013	2012
Cash From Operating Activities	**3,526**	3,539	3,420
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(135)**	(120)	(113)
Net Change in Non-Cash Working Capital	**182**	50	(110)
Cash Flow	**3,479**	3,609	3,643

In 2014, Cash Flow decreased $130 million primarily due to:

- Lower Operating Cash Flow, as discussed above; and
- A decrease in interest income as a result of receiving the remaining principal and interest due under the Partnership Contribution Receivable in December 2013.

Declines in Cash Flow were partially offset by:

- Lower finance costs as a result of the prepayment of the Partnership Contribution Payable in the first quarter of 2014 and a premium paid on the early redemption of senior unsecured notes in the third quarter of 2013;
- A decrease in current income tax, primarily due to a favourable adjustment related to prior years and a decrease in U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income; and
- A pre-exploration expense of $64 million recorded in 2013.

Operating Earnings

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as Earnings Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below, less income taxes on Operating Earnings before tax.

In December 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable. This resulted in the crystallization of realized foreign exchange losses from a stronger Canadian dollar as compared with the date when the note was originally issued. This realized foreign exchange loss has been excluded from the calculation of Operating Earnings as it is not reflective of our ongoing operations.

($ millions)	**2014**	2013	2012
Earnings, Before Income Tax	**1,195**	1,094	1,778
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (1)	**(596)**	415	(57)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**458**	52	(84)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable	**-**	146	-
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Operating Earnings, Before Income Tax	**901**	1,708	1,637
Income Tax Expense	**268**	537	769
Operating Earnings	**633**	1,171	868

(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 the Partnership Contribution Receivable and foreign exchange (gains) losses on settlement of intercompany transactions.

In 2014, Operating Earnings decreased $538 million primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million associated with our Pelican Lake property included in the Northern Alberta cash-generating unit ("CGU");
- An increase in DD&A primarily related to higher DD&A rates at our oil sands properties, an increase in sales volumes and a PP&E impairment of $65 million; and
- An increase in exploration expense primarily related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

These decreases were partially offset by lower deferred income tax primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014. The goodwill impairment charge is non-deductible for tax purposes.

Net Earnings

($ millions)	**2014 vs. 2013**	2013 vs. 2012
Net Earnings, Comparative Year	**662**	995
Increase (Decrease) due to:		
Operating Cash Flow (1)	**(310)**	17
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**1,011**	(472)
Unrealized Foreign Exchange Gain (Loss)	**(371)**	(110)
Gain (Loss) on Divestiture of Assets	**157**	(1)
Expenses (2)	**196**	(217)
Depreciation, Depletion and Amortization	**(113)**	(248)
Goodwill Impairment	**(497)**	393
Exploration Expense	**28**	(46)
Income Tax Expense	**(19)**	351
Net Earnings, End of Year	**744**	662

(1) Non-GAAP measure defined in this MD&A.
(2) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations operating expenses.

Net Earnings increased 12 percent in 2014 primarily due to:

- Unrealized risk management gains before tax of $596 million (2013 – unrealized losses before tax of $415 million);
- A gain of $156 million on the sale of non-core assets; and
- The absence of a realized foreign exchange loss in 2014 related to the Partnership Contribution Receivable. In 2013, a realized foreign exchange loss of $146 million was recorded related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above.

The increases in Net Earnings were partially offset by:

- A decline in Operating Earnings of $538 million as discussed above; and
- Non-operating unrealized foreign exchange losses of $458 million (2013 – loss of $52 million).

Net Earnings decreased $333 million in 2013 compared with 2012 primarily due to unrealized risk management losses compared with gains in 2012 and an increase in DD&A, partially offset by the absence of a goodwill impairment in 2013 compared with a goodwill impairment of $393 million recorded in 2012 in our Conventional segment.

Net Capital Investment

($ millions)	**2014**	2013	2012
Oil Sands	**1,986**	1,885	1,697
Conventional	**840**	1,189	1,362
Refining and Marketing	**163**	107	118
Corporate and Eliminations	**62**	81	191
Capital Investment	**3,051**	3,262	3,368
Acquisitions	**18**	32	114
Divestitures	**(277)**	(283)	(76)
Net Capital Investment (1)	**2,792**	3,011	3,406

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

Oil Sands capital investment in 2014 focused primarily on the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 320 gross stratigraphic test wells.

In 2014, Conventional capital investment focused primarily on tight oil development, facilities work and the addition of infill drilling pads at Pelican Lake. Spending on natural gas activities continues to be strategically focused on a small number of high return opportunities.

Our capital investment in the Refining and Marketing segment focused on capital maintenance, projects improving refinery reliability and safety, and refinery optimization projects.

Capital also includes spending on technology development, which plays an integral role in our business. Having a strategy focused on innovation and technology development is vital to our ability to minimize our environmental footprint and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to potentially reduce costs, enhance the recovery techniques we use to access crude oil and natural gas and improve our refining processes. In 2014, our capital investment included $101 million on technology development activities.

Capital investment in our Corporate and Eliminations segment includes spending on corporate assets, such as computer equipment, leasehold improvements and office furniture.

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

Acquisitions and Divestitures

As part of our business plan, we look for opportunities to manage our portfolio in areas where we may apply our core competencies in crude oil development.

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. In 2013, divestitures primarily included the sale of our Lower Shaunavon asset for net proceeds of $241 million.

In 2014 and 2013, we had no material acquisitions.

Capital Investment Decisions

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

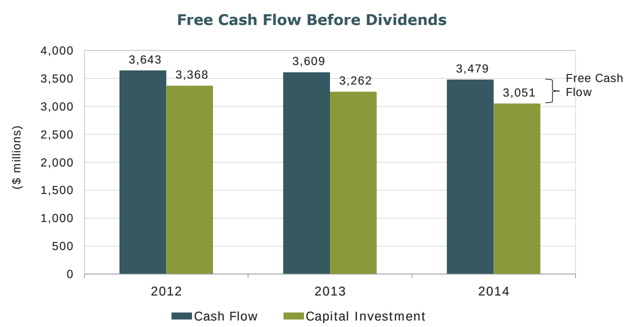
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital, which is the capital spending for projects beyond our committed capital projects.

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow. We anticipate maintaining investment grade credit ratings. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio.

Cash flow from our crude oil, natural gas and refining operations is expected to fund a portion of our cash requirements, with any remainder funded through prudent use of our balance sheet capacity and management of our asset portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

($ millions)	**2014**	2013	2012
Cash Flow (1)	**3,479**	3,609	3,643
Capital Investment (Committed and Growth)	**3,051**	3,262	3,368
Free Cash Flow (2)	**428**	347	275
Dividends Paid	**805**	732	665
	(377)	(385)	(390)

(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.



In January 2015, we revised our 2015 capital budget in order to preserve cash and maintain the strength of our balance sheet in the current low crude oil price environment. We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. Refer to the Reportable Segments section of this MD&A for more details and the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

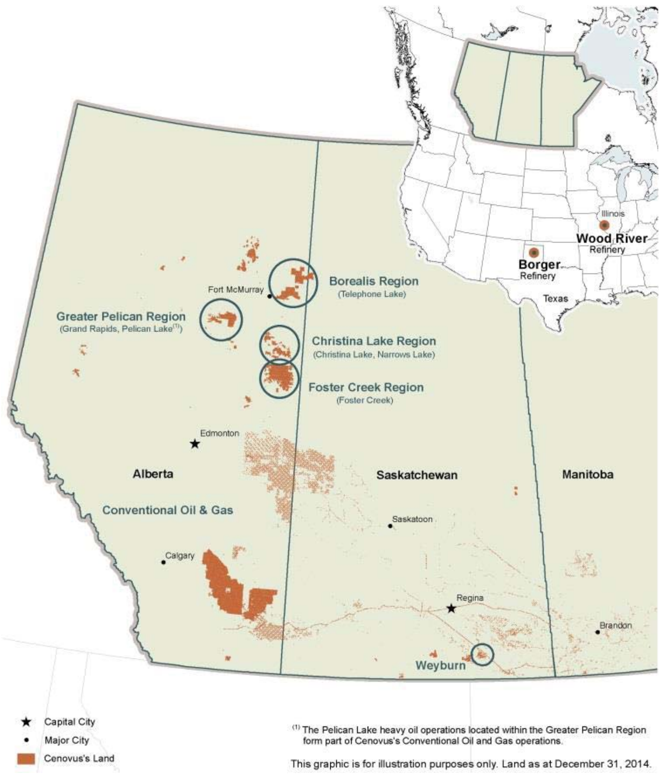
REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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. This segment also includes 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. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.



(1) The Pelican Lake heavy oil operations located within the Greater Pelican Region form part of Cenovus's Conventional Oil and Gas operations.

This graphic is for illustration purposes only. Land as at December 31, 2014.

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)	2014	2013	2012
Oil Sands	**4,800**	3,780	3,170
Conventional	**2,996**	2,776	2,599
Refining and Marketing	**12,658**	12,706	11,356
Corporate and Eliminations	**(812)**	(605)	(283)
	19,642	18,657	16,842

OIL SANDS

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

Significant developments that impacted our Oil Sands segment in 2014 compared with 2013 include:

- Christina Lake production increasing 40 percent, to an average of 69,023 barrels per day, with phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facility and better reservoir performance with strong base well performance and a lower SOR;
- Commencing first production at Foster Creek phase F in the third quarter of 2014. Production ramp up is expected to take approximately eighteen months;
- Foster Creek production averaging 59,172 barrels per day primarily due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology;

- Completing a planned turnaround at Christina Lake phases A and B and Foster Creek, with minimal impact to production. Christina Lake production volumes were processed through the phase C, D and E plant and the Foster Lake planned turnaround was smaller in scale as compared to the major planned turnaround in 2013;
- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake; and
- Receiving regulatory approval for expansion of the Foster Creek development area.

Oil Sands – Crude Oil

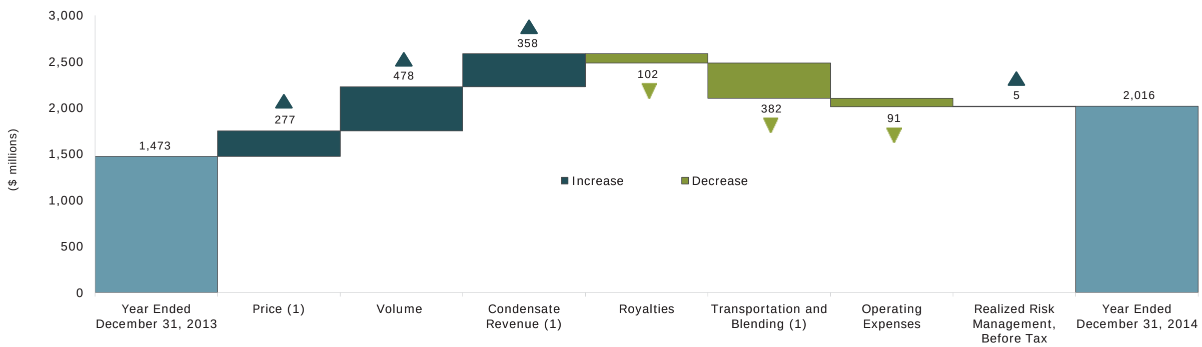
Financial and Per-unit Results

($ millions, unless otherwise noted [1])	2014	2014 $ per-unit	2013	2013 $ per-unit	2012	2012 $ per-unit
Gross Sales	**4,963**	109	3,850	103	3,307	102
Less: Royalties	**233**	5	131	4	186	6
Revenues	**4,730**	104	3,719	99	3,121	96
Expenses						
Transportation and Blending	**2,130**	47	1,748	47	1,499	46
Operating	**622**	14	531	14	401	12
(Gain) Loss on Risk Management	**(38)**	(1)	(33)	(1)	(46)	(1)
Operating Cash Flow	**2,016**	44	1,473	39	1,267	39
Capital Investment	**1,980**		1,880		1,689	
Operating Cash Flow Net of Related Capital Investment	**36**		(407)		(422)	

(1) *Per-unit amounts are calculated on an unblended crude oil basis.*

Capital investment in excess of Operating Cash Flow in 2013 and 2012 was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Operating Cash Flow Variance



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

Revenues

Pricing

In 2014, our average oil sands crude oil sales price was $65.18 per barrel (excluding financial hedging), a 10 percent increase from 2013. This is consistent with the increase in the WCS and CDB benchmark prices and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 38 percent, to a discount of US$3.94 per barrel (2013 – a discount of US$6.33 per barrel), primarily due to greater access to refineries that can process heavier crude oil from improved pipeline access to the U.S. Gulf Coast and increased rail takeaway capacity. In 2014, 59,266 barrels per day of Christina Lake production was sold as CDB (2013 – 42,664 barrels per day), 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)	2014	Percent Change	2013	Percent Change	2012
Foster Creek	**59,172**	**11%**	53,190	(8)%	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736

Christina Lake production increased significantly as a result of phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities, and better reservoir performance with strong base well performance and a lower SOR. We completed a planned partial turnaround in the second quarter of 2014 that had a minimal impact on production as volumes were processed through the phase C, D and E plant. In 2013, a planned full turnaround was performed that reduced production by approximately 1,900 barrels per day.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. We also achieved first production from phase F in September 2014, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it through pipelines to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered in 2014 increased compared with 2013.

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)	**2014**	2013	2012
Foster Creek	**8.8**	5.8	11.8
Christina Lake	**7.5**	6.8	6.2

Royalties increased $102 million in 2014, primarily related to the royalty calculation at Foster Creek based on net profits that resulted in an effective royalty rate of 8.8 percent in 2014 compared with a calculation using gross revenues in 2013 (effective royalty rate – 5.8 percent), an increase in sales volumes and higher realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $382 million or 22 percent. Blending costs rose primarily due to an increase in condensate volumes, consistent with the rise in production. In 2014, we recorded a $6 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices. Transportation charges increased $18 million due to a rise in production and higher volumes transported by rail, partially offset by lower sales into the U.S. market which attract higher tariffs.

Operating

Primary drivers of our operating expenses in 2014 were fuel, workforce and workover activities. While total operating expenses increased $91 million, on a per-unit basis, costs decreased to $13.66 per barrel primarily as a result of the increase in production.

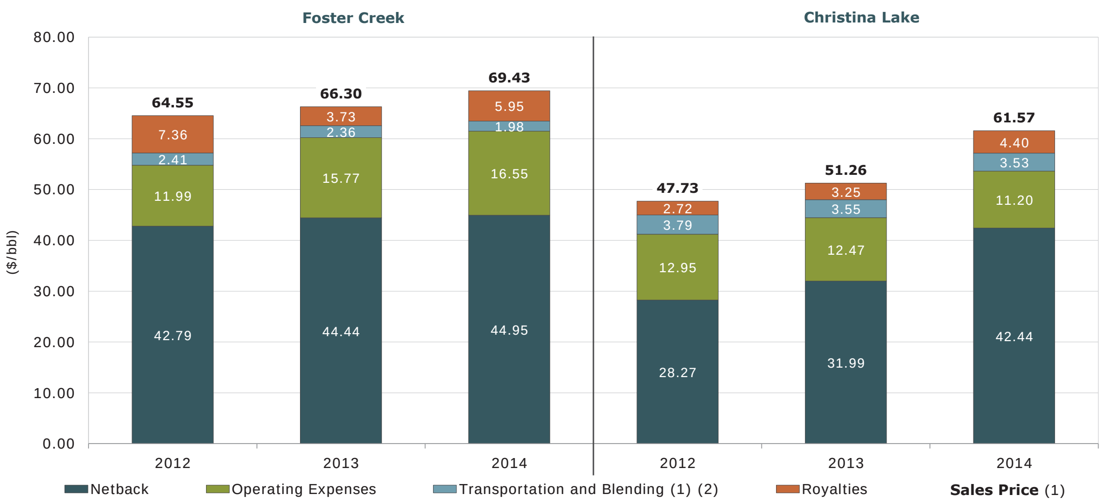
Per-unit Operating Expenses

($/bbl)	2014	Percent Change	2013	Percent Change	2012
Foster Creek					
Fuel	**4.46**	**55%**	2.88	42%	2.03
Non-fuel	**12.09**	**(6)%**	12.89	29%	9.96
Total	**16.55**	**5%**	15.77	32%	11.99
Christina Lake					
Fuel	**3.65**	**20%**	3.03	25%	2.42
Non-fuel	**7.55**	**(20)%**	9.44	(10)%	10.53
Total	**11.20**	**(10)%**	12.47	(4)%	12.95
Total	**13.66**	**(4)%**	14.19	15%	12.33

At Foster Creek, fuel costs continue to have a significant impact on our per-unit operating expenses, increasing $1.58 per barrel. The increase is due to higher natural gas prices and an increase in consumption resulting from a higher SOR. The increase in the SOR was due to the ramp up of Foster Creek phase F. Non-fuel operating expenses declined $0.80 per barrel, primarily due to a rise in production as a result of improved performance at our facilities.

At Christina Lake, fuel costs increased by $0.62 per barrel due to a rise in natural gas prices, partially offset by a decrease in fuel consumption on a per barrel basis. Non-fuel operating expenses decreased $1.89 per barrel, primarily due to an increase in production and a decline in fluid, waste handling and trucking costs as a result of work done to optimize chemicals used. Declines were partially offset by an increase in workover activities related to well servicing.

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 2014 was $42.01 per barrel (2013 – $42.41 per barrel; 2012 – $41.85 per barrel) for Foster Creek; and $45.45 per barrel (2013 – $45.25 per barrel; 2012 – $45.83 per barrel) for Christina Lake.

(2) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities resulted in realized gains of $38 million (2013 – realized gains of $33 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operations in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2014, net of internal usage, was 22 MMcf per day (2013 – 21 MMcf per day). Operating Cash Flow was $45 million in 2014 (2013 – $22 million), primarily due to higher natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	2014	2013	2012
Foster Creek	**796**	797	735
Christina Lake	**794**	688	593
	1,590	1,485	1,328
Narrows Lake	**175**	152	44
Telephone Lake	**112**	93	138
Grand Rapids	**63**	39	65
Other (1)	**46**	116	122
Capital Investment (2)	**1,986**	1,885	1,697

(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 2014 focused on expansion phases F, G and H, offsite facility work related to phases G and H, drilling of sustaining wells including the use of our Wedge Well™ technology, and operational improvement projects. Costs related to the expansion of phases F, G and H increased more than expected as a result of changes to the phases that we believe will result in better long-term plant reliability and production efficiency. These include improvements to the plant safety systems, completion designs and the incorporation of recent regulatory changes. Capital investment remained relatively consistent year over year due to higher spending on offsite facilities, drilling and completions on well pairs and wells using our Wedge Well™ technology, offset by a decrease in spending on plant facilities and operational improvement projects.

In 2014, Christina Lake capital investment focused on expansion phases F and G, phase E well pad and facility construction, and sustaining well programs including the use of our Wedge Well™ technology. Capital investment increased due to sustaining well programs including our Wedge Well™ technology, and phases F and G plant engineering, procurement and construction, partially offset by reduced spending on phase E plant construction.

Capital investment at Narrows Lake increased as spending continued on phase A engineering, procurement and plant construction. Spending on phase A plant construction started in the third quarter of 2013.

Emerging Projects

In 2014, Telephone Lake capital investment was primarily focused on preliminary engineering work on the central processing facility, costs related to the dewatering pilot project and the drilling of stratigraphic test wells. Capital spending increased as a result of our ability to have a summer stratigraphic well program due to our SkyStrat™ drilling rig, which focused on acreage acquired in 2014 adjacent to the central processing facility site.

Capital investment at Grand Rapids in 2014 was primarily focused on costs related to the pilot project and the drilling of stratigraphic test wells. Capital investment increased due to the dismantling and removal of the Joslyn facility which we plan to install at Grand Rapids, partially offset by a decline in costs related to our 2014 winter program.

Drilling Activity

	Gross Stratigraphic Test Wells (1)			Gross Production Wells (2) (3)		
	2014	2013	2012	**2014**	2013	2012
Foster Creek	**165**	112	141	**63**	56	28
Christina Lake	**57**	74	98	**67**	35	32
	222	186	239	**130**	91	60
Narrows Lake	**22**	26	42	**-**	-	-
Telephone Lake	**45**	28	29	**-**	-	-
Grand Rapids	**10**	3	62	**-**	-	1
Other	**21**	96	96	**-**	-	-
	320	339	468	**130**	91	61

(1) 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 2014, we drilled 14 wells (2013 – 24 wells; 2012 – 15 wells).
(2) SAGD well pairs are counted as a single producing well.
(3) Includes wells drilled using our Wedge Well™ technology.
(4) In addition to the drilling activity above, we drilled three gross service wells in 2014 (2013 – 27 gross service wells; 2012 – 34 gross service wells).

Stratigraphic test wells were drilled at Foster Creek, Christina Lake and Narrows Lake to help identify well pad locations for the expansion phases under construction, add contingent resources and increase well density per section for future expansion phases. Other stratigraphic test wells were drilled to continue gathering data on the quality of our projects and to support regulatory applications for project approval.

Future Capital Investment

As a result of the current low crude oil price environment, we have decided to slow capital activities in 2015 in order to preserve cash and maintain the strength of our balance sheet. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. In addition, we expect to see reductions in demand for labour, service and materials which should create potential opportunities for us to drive improvements in our cost structure. Our capital budget has a degree of flexibility and as such we will continue to assess spending plans on a regular basis and make adjustments, if required.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 is forecast to be between $550 million and $600 million and we plan to focus on our existing operations as well as expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day. First production from phase G is anticipated in the first half of 2016. Spending related to phase H, with an initial design capacity of 30,000 barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrel per day phase.

Christina Lake is producing from phases A through E. Capital investment in 2015 is forecast to be between $650 million and $700 million and we plan to focus on activities necessary for our existing operations, expansion phase F and the phase C, D and E optimization program. Expansion work on phase F, including cogeneration, is expected to continue as planned. We expect to add production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The phase C, D and E optimization program is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015. Spending related to phase G, with an initial design capacity of 50,000 gross barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. We submitted a joint application and environmental impact assessment to regulators in March 2013 for the phase H expansion, a 50,000 gross barrel per day phase, for which we expect to receive regulatory approval in the first half of 2015.

Capital investment at Narrows Lake is forecast to be between $30 million and $40 million in 2015. In 2015, we plan to focus our capital investment on detailed engineering and procurement. We have suspended new construction spending on phase A until crude oil prices recover. In 2012, we received regulatory approval for Narrows Lake phases A, B and C, for 130,000 gross barrels per day, and partner approval for phase A, a 45,000 gross barrel per day phase.

Emerging Projects

Two of our emerging projects are Telephone Lake and Grand Rapids. Capital investment for our new resource plays is forecast to be between $90 million and $100 million in 2015 and we plan to focus on continuing the pilot project at Grand Rapids and the dismantling, removal and reconstruction of the Joslyn facility as well as front-end engineering at Telephone Lake. At Grand Rapids, we are planning on drilling a third pilot well pair in the first quarter of 2015 and plan to continue operating the SAGD pilot project to gather additional information on the reservoir.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total 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 total proved reserves.

In 2014, Oil Sands DD&A increased $179 million. The increases were due to higher DD&A rates for both of our properties from additional expenditures and a rise in future development costs associated with total proved reserves, and an increase in sales volumes.

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, the heavy oil assets at Pelican Lake and developing tight oil assets in Alberta. Pelican Lake produces conventional heavy oil using polymer flood technology. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

We own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Production from fee lands comprises approximately 50 percent of our total conventional production. Fee lands where we have maintained working interest production are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In 2014, we had approximately 7,600 barrels of oil equivalent per day of royalty interest production from fee lands which resulted in Operating Cash Flow of approximately $150 million.

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. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment.

Significant developments that impacted our Conventional segment in 2014 compared with 2013 include:

- Crude oil production averaging 75,298 barrels per day, decreasing two percent. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake, was more than offset by expected natural declines and the sale of non-core assets;
- Generating Operating Cash Flow net of capital investment of $1,047 million, an increase of 68 percent; and
- Recording goodwill impairment of $497 million primarily due to declines in crude oil prices and a slowing down of the Pelican Lake development plan, a PP&E impairment of $65 million related to assets for which we do not believe the carrying value can be recovered, and an exploration expense of $82 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

In September 2014, we completed the sale of certain of our Wainwright assets in Alberta for net proceeds of $234 million. A gain on disposition of $137 million was recorded on the sale. Prior to the sale, crude oil production from these assets was 2,775 barrels per day for the first three quarters in 2014 (year ended December 31, 2013 – 2,566 barrels per day).

In April 2014, we sold certain of our Bakken assets in southeastern Saskatchewan for net proceeds of $35 million. A gain on disposition of $16 million was recorded on the sale. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (year ended December 31, 2013 – 562 barrels per day).

In both the Wainwright and Bakken asset dispositions, we retained ownership of mineral interests in the applicable fee lands and receive a royalty on current and future production.

In July 2013, we sold our Lower Shaunavon asset for net proceeds of $241 million. Production averaged 4,236 barrels per day in the first half of 2013.

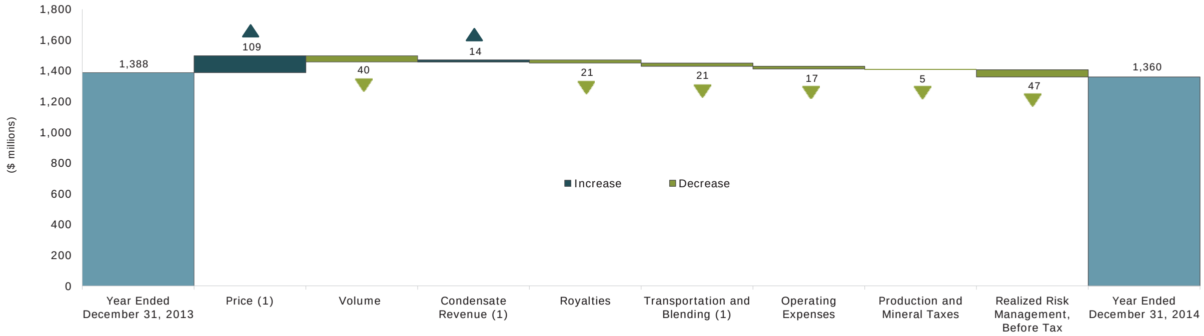
Conventional – Crude Oil

Financial and Per-unit Results

	2014		2013		2012	
($ millions, unless otherwise noted [1])		$ per-unit		$ per-unit		$ per-unit
Gross Sales	**2,456**	90	2,373	85	2,289	82
Less: Royalties	**217**	8	196	7	195	7
Revenues	**2,239**	82	2,177	78	2,094	75
Expenses						
Transportation and Blending	**326**	12	305	11	278	10
Operating	**512**	19	495	18	441	16
Production and Mineral Taxes	**37**	1	32	1	34	1
(Gain) Loss on Risk Management	**4**	-	(43)	(2)	(39)	(1)
Operating Cash Flow	**1,360**	50	1,388	50	1,380	49
Capital Investment	**812**		1,167		1,319	
Operating Cash Flow Net of Related Capital Investment	**548**		221		61	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

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 increased five percent to $81.62 per barrel (excluding financial hedging), consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

(barrels per day)	**2014**	**Percent Change**	2013	Percent Change	2012
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9)%**	15,991	-%	16,015
Total Heavy Oil	**39,546**	**(2)%**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3)%**	35,467	(2)%	36,071
NGLs	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2)%**	76,775	1%	75,667

Increased production from successful horizontal well performance in southern Alberta and a slight increase in production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Higher production at Pelican Lake, related to an increased response from the polymer flood program and additional infill wells coming on stream was partially offset by a planned turnaround.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered increased.

Royalties

Royalties increased $21 million primarily due to higher realized sales prices, partially offset by a decline in sales volumes. In 2014, the effective crude oil royalty rate for our Conventional properties was 10.1 percent (2013 – 9.5 percent).

Approximately 50 percent of our production is not subject to royalties, rather is subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In 2014, production and mineral taxes increased, consistent with the rise in crude oil prices for the full year.

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); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. In 2014 and 2013, the Pelican Lake royalty calculation was based on gross revenues.

Expenses

Transportation and Blending

Transportation and blending costs increased $21 million. Blending costs rose primarily due to an increase in condensate volumes and higher condensate prices. In 2014, we recorded a $12 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices as at year end. Transportation charges were $5 million lower due to a decrease in volumes moved by rail and a decline in sales volumes.

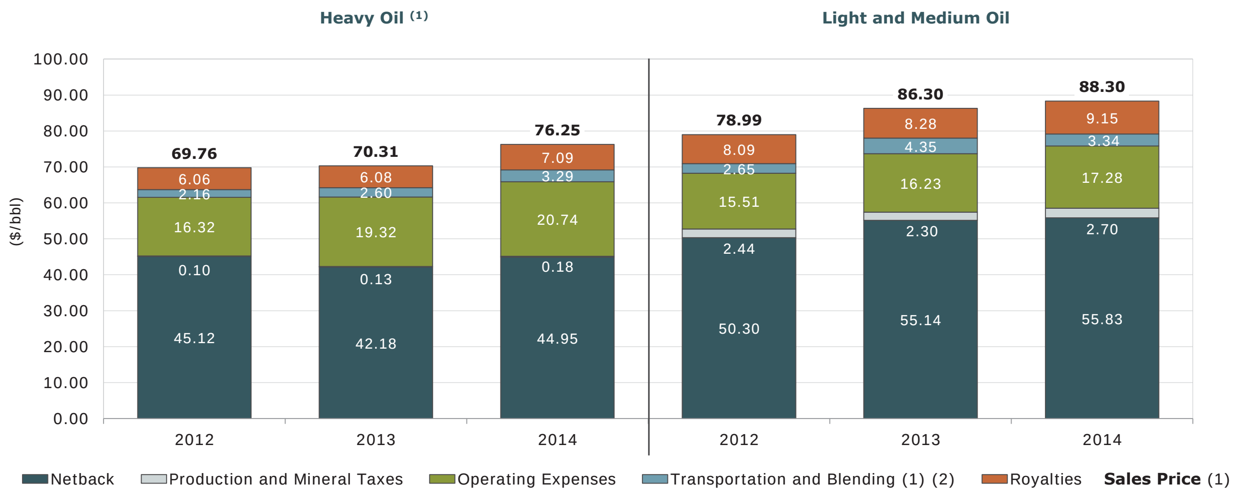
Operating

Primary drivers of our operating expenses in 2014 were workover activities, workforce costs, repairs and maintenance, electricity, and chemical consumption. Operating expenses rose $17 million to $18.81 per barrel.

Operating expenses increased $1.20 per barrel, primarily due to:
- Higher chemical costs associated with a rise in the price of polymer and an increase in polymer consumption. Operating expenses include polymer as it is consumed when it is injected into the reservoir as part of the waterflood process; and
- A rise in fluid, waste handling and trucking costs associated with wells drilled in 2014.

Increased crude oil operating expenses were partially offset by declines related to the sale of non-core assets, in addition to lower electricity costs as a result of a decline in electricity prices.

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 $15.71 per barrel (2013 – $14.60 per barrel; 2012 – $14.66 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. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities in 2014 resulted in realized losses of $4 million (2013 – realized gains of $43 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	2014	2013	2012
Gross Sales	**744**	594	498
Less: Royalties	**12**	8	6
Revenues	**732**	586	492
Expenses			
Transportation and Blending	**20**	20	19
Operating	**200**	209	217
Production and Mineral Taxes	**9**	3	3
(Gain) Loss on Risk Management	**(5)**	(61)	(229)
Operating Cash Flow	**508**	415	482
Capital Investment	**28**	22	43
Operating Cash Flow Net of Related Capital Investment	**480**	393	439

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

Revenues

Pricing

Our average natural gas sales price increased $1.17 per Mcf to $4.37 per Mcf, consistent with the rise in the AECO benchmark price.

Production

Production decreased eight percent to 466 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased slightly as higher prices more than offset the impact of production declines. The average royalty rate in 2014 was 1.6 percent (2013 – 1.4 percent). Most of our natural gas production is located on fee lands where we hold mineral rights, which results in mineral tax being recorded within production and mineral taxes. In 2014, production and mineral taxes increased, consistent with the rise in natural gas prices, partially offset by the decline in volume.

Expenses

Transportation

Transportation costs remained consistent as a result of lower production volumes, partially offset by higher pipeline rates.

Operating

In 2014, our operating expenses were primarily composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses decreased $9 million primarily due to natural production declines and decreases in electricity costs, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $5 million (2013 – realized gains of $61 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment [(1)]

($ millions)	2014	2013	2012
Pelican Lake	246	463	514
Other Heavy Oil	92	135	126
Light and Medium Oil	474	569	679
Natural Gas	28	22	43
	840	1,189	1,362

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

Capital investment in 2014 was primarily composed of spending on tight oil development and facilities work. At Pelican Lake, capital investment focused on infill drilling, maintenance capital and facility upgrades associated with the expansion of the polymer flood. Spending on natural gas activities continues to be managed in response to the natural gas price environment and to focus on well recompletions. The decline in capital investment at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	2014	2013	2012
Crude Oil	126	212	352
Recompletions	803	751	977
Gross Stratigraphic Test Wells	30	54	19
Other [(1)]	40	77	115

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

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are primarily related to lower-risk Alberta coal bed methane development.

Future Capital Investment

In 2015, crude oil capital investment is forecast to be between $200 million and $215 million with spending mainly focused on maintenance capital and spending for our CO_2 facility at Weyburn. As a result of the current low crude oil price environment, our 2015 capital spending reflects the suspension of the majority of our 2015 drilling program in southern Alberta and Saskatchewan.

DD&A, Goodwill Impairment and Exploration Expense

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total 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 total proved reserves.

Conventional DD&A decreased $88 million in 2014. The decrease was primarily due to a decline in sales volumes and lower DD&A rates from a decrease in expenditures and the non-core asset sales.

In the fourth quarter of 2014, an impairment loss of $52 million was recorded related to the carrying amount of purchased equipment that will now not be used in its intended location, and we do not believe the carrying value can be recovered through a sale. In the second quarter of 2014, we recorded an impairment loss related to a minor natural gas property that was shut-in and abandonment commenced. 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 included in our Northern Alberta CGU. The impairment was primarily due to a decline in crude oil prices and a slowing down of the Pelican Lake development plan. There was no goodwill impairment in 2013.

Exploration Expense

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been established are capitalized as E&E assets. If a field, area or project is determined not to be technically feasible and commercially viable or we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In 2014, $82 million (2013 – $50 million) of previously capitalized E&E costs, related to certain conventional tight oil exploration assets, were deemed not to be commercially viable and technically feasible and were recorded as exploration expense.

As part of our business plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. In 2013, as a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded. There was no pre-exploration expense recorded in 2014.

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 allows 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. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $60 million on our refining gross margin.

Significant developments that impacted our Refining and Marketing segment in 2014 compared with 2013 include:

- Crude oil runs and refined product output decreasing four percent as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery;
- Operating Cash Flow declining 82 percent to $211 million primarily due to lower average market crack spreads, an increase in heavy crude oil feedstock costs, higher operating expenses, an inventory write-down of $113 million primarily related to the significant decline in refined product prices, and a decrease in refined product output; and
- In the fourth quarter of 2014, the rapidly declining commodity price environment resulted in the cost of feedstock processed being higher than the refined product pricing we realized in December.

Refinery Operations [1]

	2014	2013	2012
Crude Oil Capacity [2] (Mbbls/d)	**460**	457	452
Crude Oil Runs (Mbbls/d)	**423**	442	412
Heavy Crude Oil	**199**	222	198
Light/Medium	**224**	220	214
Refined Products (Mbbls/d)	**445**	463	433
Gasoline	**231**	232	216
Distillate	**137**	144	138
Other	**77**	87	79
Crude Utilization (percent)	**92**	97	91

(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 in 2013, increased effective January 1, 2014.

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 continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In 2014, an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery reduced crude oil runs, refined product output and crude utilization when compared with 2013. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however to a lesser extent.

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 amount of heavy crude oil processed in 2014 decreased primarily as a result of processing higher volumes of medium crude oil due to more favourable economics.

Financial Results

($ millions)	2014	2013	2012
Revenues	**12,658**	12,706	11,356
Purchased Product	**11,767**	11,004	9,506
Gross Margin	**891**	1,702	1,850
Expenses			
Operating	**707**	540	581
(Gain) Loss on Risk Management	**(27)**	19	(4)
Operating Cash Flow	**211**	1,143	1,273
Capital Investment	**163**	107	118
Operating Cash Flow Net of Related Capital Investment	**48**	1,036	1,155

Gross Margin

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

In the fourth quarter of 2014, we experienced a rapidly declining commodity price environment. This resulted in the cost of feedstock processed being significantly higher than the refined product pricing we realized in December due to the time lag discussed above and the valuation of our feedstock costs on a FIFO accounting basis.

In 2014, the decrease in gross margin was primarily due to:

- Lower average market crack spreads which decreased by approximately 20 percent, consistent with the narrowing of the Brent-WTI differential;
- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential;
- An inventory write-down of $113 million primarily related to our refined product and feedstock inventory, consistent with the decline in benchmark prices; and
- A decline in refined product output by four percent as discussed above.

Our refineries do not blend renewable fuels into the motor fuel products we produce, so consequently we are obligated to purchase Renewable Identification Numbers ("RINs"). In 2014, the cost of our RINs was $123 million (2013 – $153 million). These decreases are consistent with the decline in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in 2014 were maintenance, labour, utilities and supplies. Operating expenses increased 31 percent primarily due to higher planned turnaround and maintenance activities, an increase in utility costs resulting from a rise in natural gas costs and a weaker Canadian dollar.

Refining and Marketing – Capital Investment

($ millions)	**2014**	2013	2012
Wood River Refinery	**101**	64	54
Borger Refinery	**61**	42	64
Marketing	**1**	1	-
	163	107	118

Capital expenditures in 2014 focused on capital maintenance and refinery reliability and safety projects. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We are currently awaiting permit approval, which is anticipated in the first half of 2015, and planned start-up is anticipated in 2016.

In 2015, we expect to invest between $240 million and $260 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased $18 million 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. In 2014, our risk management activities resulted in $596 million of unrealized gains, before tax (2013 – $415 million of unrealized losses, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	**2014**	2013	2012
General and Administrative	**358**	349	350
Finance Costs	**445**	529	455
Interest Income	**(33)**	(96)	(109)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)
Research Costs	**15**	24	15
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)
	1,036	1,017	686

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2014 were workforce, office rent and information technology costs. General and administrative expenses increased $9 million primarily due to higher staffing 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 decreased $84 million in 2014. The decrease was primarily due to lower interest incurred on the Partnership Contribution Payable as we exercised our right to prepay in the first quarter of 2014, and the recording of a US$32 million premium on the early redemption of senior unsecured notes in the third quarter of 2013, partially offset by higher unwinding of the discount on decommissioning liabilities and a weakening of the Canadian dollar.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable was 5.0 percent (2013 – 5.2 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In December 2013, the balance of the Partnership Contribution Receivable was received therefore no related interest income was earned in 2014.

Foreign Exchange

($ millions)	2014	2013	2012
Unrealized Foreign Exchange (Gain) Loss	411	40	(70)
Realized Foreign Exchange (Gain) Loss	-	168	50
	411	208	(20)

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at December 31, 2014. In addition, unrealized foreign exchange losses were lower in 2013 as a result of the reversal of previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

In December 2013, we received the remaining principal of the Partnership Contribution Receivable resulting in the recognition of a realized foreign exchange loss of $146 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 2014 was $83 million (2013 – $79 million).

(Gain) Loss on Divestiture of Assets

Divestitures in 2014 primarily included the sale of non-core assets for net proceeds of $269 million resulting in a gain of $153 million.

Income Tax Expense

($ millions)	2014	2013	2012
Current Tax			
Canada	94	143	188
U.S.	(2)	45	121
Total Current Tax	92	188	309
Deferred Tax	359	244	474
	451	432	783

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

($ millions, except percent amounts)	2014	2013	2012
Earnings Before Income Tax	1,195	1,094	1,778
Canadian Statutory Rate	25.2%	25.2%	25.2%
Expected Income Tax	301	276	448
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	(43)	87	119
Non-deductible Stock-based Compensation	13	10	10
Foreign Exchange Gain (Loss), not Included in Net Earnings	(13)	19	14
Non-taxable Capital (Gains) Losses	124	31	(7)
Derecognition (Recognition) of Capital Losses	(9)	15	(22)
Adjustments Arising From Prior Year Tax Filings	(16)	(13)	33
Withholding Tax on Foreign Dividends	-	-	68
Goodwill Impairment	125	-	99
Other	(31)	7	21
Total Tax	451	432	783
Effective Tax Rate	37.7%	39.5%	44.0%

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 taxes is adequate. There are usually a number of tax matters under review 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.

The 2014 provision for income tax includes the effect of a favourable adjustment to current tax related to prior years, which was mostly offset by increased deferred tax and therefore had a minimal impact on total income tax.

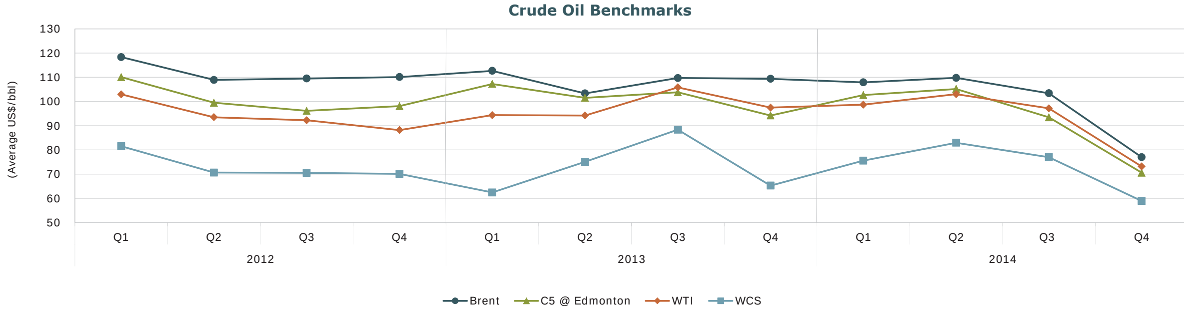
Current income tax decreased $96 million primarily due to the favourable adjustment related to prior years and lower U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income. Deferred income tax increased $115 million due to an unrealized risk management gain compared with a loss in the prior year, an increase in Canadian timing differences arising from increased Oil Sands income and the effect of the favourable adjustment to current tax related to prior years, partially offset by a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. 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.

The decrease in our effective tax rate when compared with 2013 is primarily due to a decrease in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, partially offset by the non-deductible charge for a goodwill impairment and non-deductible foreign exchange losses. In 2014, the U.S. statutory rate was 38.1 percent (2013 – 38.5 percent).

QUARTERLY RESULTS

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014 with declining crude oil and refining benchmark prices impacting on our fourth quarter financial results. The Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. The average WTI and WCS benchmark prices declined US$24.31 per barrel and US$6.35 per barrel in the fourth quarter of 2014 compared with 2013. Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.



($ millions, except per share amounts or where otherwise indicated)	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Production Volumes									
Crude Oil (bbls/d)	216,177	199,089	201,688	196,854	188,743	176,938	171,127	180,225	177,646
Natural Gas (MMcf/d)	479	489	507	476	514	523	536	545	566
Refinery Operations									
Crude Oil Runs (Mbbls/d)	420	407	466	400	447	464	439	416	311
Refined Products (Mbbls/d)	442	429	489	420	469	487	457	439	330
Revenues	4,238	4,970	5,422	5,012	4,747	5,075	4,516	4,319	3,724
Operating Cash Flow (1)	539	1,154	1,296	1,169	976	1,153	1,125	1,214	966
Cash Flow (1)	401	985	1,189	904	835	932	871	971	697
Per Share – Diluted	0.53	1.30	1.57	1.19	1.10	1.23	1.15	1.28	0.92
Operating Earnings (Loss) (1)	(590)	372	473	378	212	313	255	391	(188)
Per Share – Diluted	(0.78)	0.49	0.62	0.50	0.28	0.41	0.34	0.52	(0.25)
Net Earnings (Loss)	(472)	354	615	247	(58)	370	179	171	(117)
Per Share – Basic	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)
Per Share – Diluted	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)
Capital Investment (2)	786	750	686	829	898	743	706	915	978
Cash Dividends	201	201	201	202	183	182	183	184	167
Per Share	0.2662	0.2662	0.2662	0.2662	0.242	0.242	0.242	0.242	0.22

(1) Non-GAAP measure defined in this MD&A.
(2) Includes expenditures on PP&E and E&E assets.

Fourth Quarter 2014 Results as Compared with the Fourth Quarter 2013

Production Volumes

Total crude oil production rose 15 percent primarily due to higher production at Foster Creek and Christina Lake. Foster Creek production averaged 68,377 barrels per day, an increase of 30 percent, due to improved performance, optimization efforts, increased production from wells using our Wedge Well™ technology, and first production from phase F in September 2014. Christina Lake production averaged 73,836 barrels per day, an increase of 20 percent, due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities and better reservoir performance.

Natural gas production in the fourth quarter of 2014 decreased seven percent as expected. We continued to focus natural gas capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Refinery Operations

Crude oil runs and refined product output decreased as a result of a planned turnaround at our Wood River refinery.

Revenue

Revenues decreased $509 million or 11 percent primarily due to:

- A decline in Refining and Marketing revenues of $450 million largely due a decrease in refined product prices consistent with a 19 percent decline in average refined product benchmark prices, and lower refined product output; and
- Our average crude oil sales price (excluding financial hedging) decreasing seven percent to $55.02 per barrel.

The decreases to revenues were partially offset by:

- Crude oil sales volume increasing four percent;
- An increase in condensate volumes, consistent with higher production; and
- A rise in natural gas sales prices (excluding financial hedging) of 21 percent to $3.89 per Mcf.

Operating Cash Flow

Operating Cash Flow decreased $437 million, or 45 percent. Upstream Operating Cash Flow increased four percent due to realized risk management gains of $133 million (2013 – realized risk management gains of $67 million), higher crude oil sales volumes and a decline in crude oil operating expenses of $22 million or $1.81 per barrel, partially offset by lower crude oil sales prices.

Refining and Marketing Operating Cash Flow declined significantly from $151 million in 2013 to a loss of $322 million in 2014. The decrease was due to higher heavy crude oil feedstock costs relative to WTI, lower refined product output, an inventory write-down and an increase in operating expenses, partially offset by higher average market crack spreads. In the fourth quarter, due to the rapid decline in crude oil and refining benchmark prices, our costs of feedstock processed, determined on a FIFO basis, was higher than the refined product price that we realized. This is due to the time lag between when we purchase crude oil feedstock and when it is processed through our refineries, which is approximately one to two months.

Cash Flow

Cash Flow decreased $434 million or 52 percent in the fourth quarter of 2014 primarily due to the decline in Operating Cash Flow discussed above and lower interest income, partially offset by lower finance costs and a current income tax recovery related to a decrease in U.S. Operating Cash Flow compared to an expense in 2013.

Operating Earnings (Loss)

Operating Earnings decreased $802 million in the fourth quarter of 2014 compared with the same period in 2013. The decline was due to a goodwill impairment, lower Cash Flow as discussed above, an increase in exploration expense and higher DD&A, partially offset by a deferred income tax recovery in 2014 compared to an expense in the prior year. The deferred income tax recovery was primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

Net Earnings (Loss)

In the fourth quarter of 2014, our net loss was $472 million, compared with a net loss of $58 million in the same period last year. Our net loss increased $414 million primarily due to a decrease in Operating Earnings as discussed above and non-operating foreign exchange losses compared with gains in 2013, partially offset by unrealized risk management gains of $416 million compared with losses of $219 million in the fourth quarter of 2013.

Capital Investment

Capital investment in the fourth quarter of 2014 was $786 million, a decrease of $112 million from the same period in 2013 primarily due to declines in spending in our Conventional segment mostly related to a decrease at Pelican Lake. The decline in spending at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program. The fourth quarter capital investment was focused on the development of our expansion phases, drilling of sustaining wells and operational improvement projects at Foster Creek and Christina Lake.

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. Our AIF for the year ended December 31, 2014, contains additional information with respect to the evaluation and reporting of our reserves and resources in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Developments in 2014 compared with 2013 include:

- Proved bitumen reserves increasing seven percent and proved plus probable bitumen reserves rising 30 percent due to:
  - Christina Lake proved reserves increasing 44 million barrels due to improved reservoir performance and proved plus probable reserves rising 446 million barrels due to area expansion and improved reservoir performance; and
  - Foster Creek proved reserves increasing 77 million barrels and proved plus probable reserves rising 273 million barrels as a result of receiving regulatory approval for expansion of the development area.
- Both heavy oil proved reserves and proved plus probable heavy oil reserves declining 13 percent. The decrease was due to the deferral of drilling at Pelican Lake and the sale of certain of our Wainwright assets, partially offset by the Elk Point development in the Wainwright area.
- Light and medium crude oil and NGLs proved reserves increasing four percent and proved plus probable reserves rising one percent as a result of the expansion of the CO_2 flood area at Weyburn.
- Natural gas proved reserves declining eight percent and proved plus probable reserves decreasing nine percent as additions and improved performance were more than offset by reductions due to production.
- Bitumen best estimate economic contingent resources decreasing 0.5 billion barrels or five percent and bitumen best estimate prospective resources staying consistent at 7.5 billion barrels. Factors impacting the results include:
  - Converting 0.8 billion barrels of contingent resources to proved and probable reserves at Christina Lake and Foster Creek; and
  - Conversion of prospective resources to contingent resources through stratigraphic drilling being offset by increases to mapped reservoir volumes at Grand Rapids.

The reserves and resources data that follows is presented as at December 31, 2014 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2015 forecast prices and costs. Comparative information as at December 31, 2013 uses McDaniel's January 1, 2014 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

Reserves

As at December 31,	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
(before royalties)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Proved	**1,970**	1,846	**156**	179	**120**	115	**796**	865
Probable	**1,330**	683	**123**	140	**46**	50	**260**	300
Proved plus Probable	**3,300**	2,529	**279**	319	**166**	165	**1,056**	1,165

Reconciliation of Proved Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2013	1,846	179	115	865
Extensions and Improved Recovery	108	14	17	23
Discoveries	-	-	-	-
Technical Revisions	63	(13)	1	98
Economic Factors	-	-	-	(12)
Acquisitions	-	-	-	2
Dispositions	-	(10)	(1)	(5)
Production [(1)]	(47)	(14)	(12)	(175)
December 31, 2014	1,970	156	120	796
Year Over Year Change	124	(23)	5	(69)
	7%	(13)%	4%	(8)%

(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, 2013	683	140	50	300
Extensions and Improved Recovery	648	7	-	13
Discoveries	-	-	-	-
Technical Revisions	(1)	(21)	(3)	(47)
Economic Factors	-	-	-	(5)
Acquisitions	-	-	-	-
Dispositions	-	(3)	(1)	(1)
Production	-	-	-	-
December 31, 2014	1,330	123	46	260
Year Over Year Change	647	(17)	(4)	(40)
	95%	(12)%	(8)%	(13)%

Economic Contingent Resources and Prospective Resources

As at December 31, (billions of barrels, before royalties)	Bitumen 2014	Bitumen 2013
Economic Contingent Resources [(1)]		
Best Estimate	9.3	9.8
Prospective Resources [(1)(2)]		
Best Estimate	7.5	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 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.

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 and related disclosure is contained in our AIF for the year ended December 31, 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2014	2013	2012
Net Cash From (Used In)			
Operating Activities	**3,526**	3,539	3,420
Investing Activities	**(4,350)**	(1,519)	(3,336)
Net Cash Provided (Used) Before Financing Activities	**(824)**	2,020	84
Financing Activities	**(797)**	(726)	592
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**52**	(2)	(11)
Increase (Decrease) in Cash and Cash Equivalents	**(1,569)**	1,292	665
Cash and Cash Equivalents	**883**	2,452	1,160

Operating Activities

Cash from operating activities was $13 million lower in 2014 mainly due to lower Cash Flow as discussed in the Financial Results section of this MD&A and the change in non-cash working capital. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $772 million at December 31, 2014 compared with $1,957 million at December 31, 2013. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In 2014, cash used in investing activities was $4,350 million, a $2,831 million increase from 2013, primarily due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014 using the funds received from the Partnership Contribution Receivable in December 2013.

Financing Activities

In 2014, we paid a dividend of $1.0648 per share (2013 – $0.968 per share). Total dividend payments in 2014 were $805 million (2013 – $732 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities increased $71 million primarily due to an increase in dividends paid.

Our long-term debt at December 31, 2014 was $5,458 million (December 31, 2013 – $4,997) 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 $461 million increase in long-term debt is due to foreign exchange.

As at December 31, 2014, 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 over the next decade. 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 as at December 31, 2014:

($ millions)	Amount	Term
Cash and Cash Equivalents	**883**	**Not applicable**
Committed Credit Facility	**3,000**	**November 2018**
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

We have a $3.0 billion committed credit facility. As of December 31, 2014, no amounts were drawn on our committed credit facility.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2014, there was no commercial paper outstanding.

U.S. Base Shelf Prospectus

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. As at December 31, 2014, no notes were issued under this U.S. base shelf prospectus.

Canadian Base Shelf Prospectus

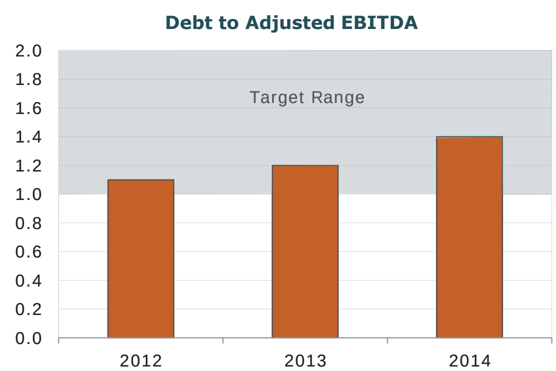
On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other 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, 2014, no notes were issued under this Canadian base shelf prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. 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 12 month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at December 31,	**2014**	2013	2012
Debt to Capitalization	**35%**	33%	32%
Debt to Adjusted EBITDA (times)	**1.4x**	1.2x	1.1x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At December 31, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the middle of our target ranges. The increase in our financial metrics at December 31, 2014 compared to the prior year resulted from higher debt balances as at December 31, 2014, due to changes in foreign exchange consistent with the weakening of the Canadian dollar, and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow from our Refining and Marketing segment. The weakening of the Canadian dollar has a positive impact on our Operating Cash Flow as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.



Debt to Capitalization is calculated as follows:

As at December 31,	**2014**	2013	2012
Debt	**5,458**	4,997	4,679
Shareholders' Equity	**10,186**	9,946	9,782
Capitalization	**15,644**	14,943	14,461
Debt to Capitalization	**35%**	33%	32%

The following is a reconciliation of Adjusted EBITDA and the calculation of Debt to Adjusted EBITDA:

As at December 31,	2014	2013	2012
Debt	**5,458**	4,997	4,679
Net Earnings	**744**	662	995
Add (Deduct):			
Finance Costs	**445**	529	455
Interest Income	**(33)**	(96)	(109)
Income Tax Expense	**451**	432	783
DD&A	**1,946**	1,833	1,585
Goodwill Impairment	**497**	-	393
E&E Impairment	**86**	50	68
Unrealized (Gain) Loss on Risk Management	**(596)**	415	(57)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)
(Gain) Loss on Divestiture of Assets	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)
Adjusted EBITDA	**3,791**	4,036	4,088
Debt to Adjusted EBITDA	**1.4x**	1.2x	1.1x

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

Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares and, subject to certain conditions, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2014, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus. In addition to its Stock Option Plan, Cenovus has a performance share unit ("PSU") plan and two deferred share unit plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to Note 27 of the Consolidated Financial Statements for more details.

As at December 31, 2014	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**757,103**	**N/A**
Stock Options	**44,411**	**17,301**
Other Stock-Based Compensation Plans	**8,396**	**1,297**

Contractual Obligations and Commitments

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)	2015	2016	2017	2018	2019	Thereafter	Total
Operating							
Pipeline Transportation (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
Other Long-term Commitments	58	24	21	15	13	116	247
Interest on Long-term Debt	293	293	293	293	293	3,720	5,185
Decommissioning Liabilities	38	32	39	65	80	8,079	8,333
Total Operating	1,136	1,115	1,117	1,358	2,136	38,343	45,205
Investing							
Capital Commitments	90	55	11	2	-	46	204
Total Investing	90	55	11	2	-	46	204
Financing							
Long-term Debt (principal only)	-	-	-	-	1,508	4,002	5,510
Total Financing	-	-	-	-	1,508	4,002	5,510
Total Payments (2)	1,226	1,170	1,128	1,360	3,644	42,391	50,919
Fixed Price Product Sales	54	55	3	-	-	-	112

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

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

In 2014, commitments for various firm pipeline transportation agreements increased $7 billion due primarily to increased costs and tolls on existing commitments, resulting in total transportation commitments of $28 billion. These agreements, most of which are subject to regulatory approval, are for terms of up to 20 years, subsequent to the date of commencement, and will help align our future transportation requirements with our anticipated production growth. We also entered into rail related commitments that increased our rail takeaway capacity to approximately 30,000 barrels per day at the end of 2014.

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. This includes continued support for proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our oil by offering a wider range of products, including existing diluted bitumen ("dilbit") blends, under blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

As at December 31, 2014, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 30 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 23 Bcf of natural gas, at a weighted average price of $4.76 per Mcf.

In the normal course of business, we also lease office space for personnel 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, 2014 or 2013, 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. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk to our risk appetite that is determined by Management and confirmed by the Board.

Risk Governance

Through our Enterprise Risk Management ("ERM") program, we have established a systematic process for identifying, measuring, prioritizing and managing risk across Cenovus.

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 their *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 the 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 exposures to the right decision makers.

Risk Management Roles and Responsibilities

The roles and responsibilities of the various participants of our ERM Program are:

The Board:
- Oversees the implementation of the ERM program by Management and provides oversight for risk management activities; and
- The Audit Committee of the Board reviews our Risk Management Framework and related processes on an annual basis to ensure processes remain current and relevant.

Senior Management:
- Confirms our corporate risk appetite with the Board. The executive team is interviewed annually and collaborative workshops are held with Senior Vice-Presidents and Vice-Presidents to support the development of the Annual Risk Report.

The Financial & Enterprise Risk Team reports to the Executive Vice-President & Chief Financial Officer and is responsible for managing our ERM program and the related risk reporting.

Principal and Strategic Risks

Cenovus's operations, financial condition, and in some cases our reputation, may be impacted by principal and strategic risks. Cenovus defines principal risks as those risks that when measured in terms of likelihood and impact, may adversely affect the achievement of our strategic or major business objectives. Strategic risk is the risk of loss from ineffective business strategies, the absence of integrated business strategies, the inability to implement those strategies, and the inability to adapt the strategies to changes in the external business, political or regulatory environment.

Principal and strategic risks are categorized into:
- Financial risks, which includes commodity price risk and liquidity risk;
- Operational risks such as risks related to health and safety, transportation restrictions, project execution, reserves replacement and the environment; and
- Regulatory risks from the regulatory approval process and changes to or introduction of environmental regulations.

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2014.

The following explains how material principal and strategic risks impact our business:

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 in commodity prices, interest rates and foreign exchange rates. These contracts may prevent Cenovus from fully realizing the benefit of price or rate increases or decreases above or below those established by these contracts. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit risk is managed through our credit policy which is approved by the Audit Committee of the Board.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, 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.

Changes in commodity prices will affect the revenues generated by the sale of our crude oil and natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. 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.

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014, and since December, crude oil prices have continued to weaken. We are anticipating prices may remain relatively low in 2015. This decline in crude oil prices has resulted 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, the carrying value of our assets may be subject to further impairments, future capital spending could be reduced causing projects to be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations. As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to make improvements in our cost structure.

We manage our commodity price exposure through a combination of activities including business integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our capital planning process is flexible, and spending can be reduced in response to declining commodity prices and other economic factors.

We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts. These transactions protect a portion of the budgeted cash flow and ensure funds are available for capital projects. These activities are reviewed and approved by the Market Risk Management Committee which is composed of the President & Chief Executive Officer, Executive Vice-President & Chief Financial Officer and Executive Vice-President, Markets, Products and Transportation. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits.

In 2014, we partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps and costless collars;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Location or quality differentials for crude oil with fixed price differential swaps and futures; and
- Electricity consumption costs through a derivative power contract.

For further 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. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(37)**	**(536)**	**(573)**	(71)	343	272
Natural Gas	**(7)**	**(55)**	**(62)**	(63)	69	6
Refining	**(26)**	**(11)**	**(37)**	18	-	18
Power	**4**	**6**	**10**	(6)	3	(3)
(Gain) Loss on Risk Management	**(66)**	**(596)**	**(662)**	(122)	415	293
Income Tax Expense (Recovery)	**20**	**152**	**172**	29	(105)	(76)
(Gain) Loss on Risk Management, After Tax	**(46)**	**(444)**	**(490)**	(93)	310	217

In 2014, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized gains on our crude oil and natural gas financial instruments as a result of changes in forward prices for transactions executed during the year, partially offset by the narrowing of forward light/heavy crude oil differentials.

Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We entered into Brent crude oil and AECO natural gas hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2015 production as well as Brent crude oil costless collars to reduce commodity price risk and retain some limited potential upside price exposure. In 2015, we have financially hedged 15 percent of our expected crude oil production on an annualized basis and 34 percent of our expected natural gas production.

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 impacting earnings before income tax on open risk management positions as at December 31, 2014 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	5	(5)
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)

Liquidity Risk

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. In declining economic times, such as the low crude oil price environment we are currently operating in, or due to unforeseen events, our liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows 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 cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2014, we had cash and cash equivalents of $883 million. No amounts were drawn on our $3.0 billion committed credit facility and no commercial paper was outstanding. 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.

We believe that our current liquidity position is sufficient to protect us in the near-term from liquidity risks related to the effects of lower crude oil prices or from unforeseen economic events that could create further volatility in cash flow.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that could impact the achievement of our objectives.

Health and Safety Risk

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or loss of life. The inability to operate safely has the potential to have a material adverse impact on Cenovus's reputation, financial condition, results of operations and cash flow.

We are committed to safety in our operations. We take an active role with our refining partner in ensuring safety is the first priority. Our safety policies and standards comply with government regulations and industry standards. To partially mitigate safety risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System to identify, assess and mitigate safety, operational and environmental risk across our operations. Cenovus endeavours to engage contractors who share the same commitment to safety. We use a third-party online safety prequalification system as well as safety performance data to assist in selecting our contractors. Prevention of occupational diseases and illnesses is also an integral part of our health and safety focus. We take a risk-based approach to systematically identify, evaluate and manage health hazards of all workers at our sites.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies for approval by our Board and oversees compliance with government laws and regulations.

Transportation Restrictions

Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades and in extreme situations, production curtailment. While this risk may impact our natural gas production, it has the greatest potential to impact our crude oil production, which could negatively affect our financial condition, results of operations and cash flows.

To help mitigate these risks, we employ a diversified sales strategy which includes utilizing multiple transportation options, including pipeline, railcar, marine and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options. We may further commit to new and expanding transportation infrastructure to access additional markets or invest in technology that improves the efficiency and cost effectiveness of transportation alternatives.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Trans Mountain Pipeline Expansion project and the Energy East Pipeline project, if approved, are expected to benefit heavy oil producers by improving access to refineries with capacity to process heavy crude oil as well as creating an option to ship crude oil offshore. The Keystone XL project is expected to connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Trans Mountain Pipeline Expansion and Northern Gateway Pipeline projects are expected to connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia. The Energy East Pipeline project is expected to carry crude oil from Alberta and Saskatchewan to refineries and marine terminals in eastern Canada. Other industry options are being developed and we are actively participating in those developments.

Capital Project Execution and Operating Risk

There are risks associated with the execution and operations of our upstream and refining projects. Over the long term, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations, availability of skilled labour, key components or other scarce resources and general economic conditions, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency and control our costs. In January 2015, we revised our 2015 capital budget in response to the current low crude oil price environment. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at Cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures. We apply a manufacturing-like approach to our phased oil sands development projects to help manage project quality, scheduling and control costs, including utilizing a templated phase design, in-house project management, construction management and commissioning/start-up teams, and Cenovus's own modular yard for fabrication of pipe rack and equipment modules.

As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to drive improvements in our cost structure.

Operational risks 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. Our operational risks include, but are not limited to health and safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, reservoir performance and technical challenges, phased execution of oil sands projects and partner risks. In addition to leveraging Cenovus's Operations Management System, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

Reserves Replacement Risk

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.

To mitigate the risk associated with replacing reserves we evaluate projects on a fully risked basis, including geological risk and engineering risk, and consider information provided by our stratigraphic well program. In addition, our asset teams undertake a project look-back process, whereby each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results and are incorporated into the current year's plan.

To date, our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our long-range business plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2014.

Personnel

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 personnel or are unsuccessful in attracting and retaining new personnel, 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. Management is investing time and resources in technical and leadership development, defining business processes, standards and metrics, and supporting effective management of change. These are key elements of our Cenovus Operations Management System.

Environmental Risk

Developing and operating our projects is subject to hazards of recovering, transporting and processing hydrocarbons which can cause damage to the environment. We take our responsibility for the environment very seriously. To manage these risks, we strive to use, recycle and dispose of water safely, manage air emissions, limit our physical footprint and minimize our impact on habitat, including wildlife. Working with our stakeholders, we identify the unique needs of the different areas where we operate. Employees, contractors and third-party service providers have the necessary skills and appropriate training needed to comply with regulations and be responsible environmental stewards. Our environmental impact is measured using the Cenovus Operations Management System to monitor, manage and accurately report our activities.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, and oversees compliance with 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 incident and remediation/reclamation programs are utilized to restore the environment.

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 impose a cost of compliance, adversely impacting our financial condition, results of operations and cash flows.

Environmental Regulation Risk

The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. However, we expect that the cost of meeting new environmental and climate change regulations will not be so high as to cause a material disadvantage to our competitive position. Non-compliance with environmental regulations could also have an adverse impact on Cenovus's reputation.

Further discussion on specific areas that currently have, and are reasonably likely to have, an impact on Cenovus's operations is below.

Species at Risk Act

The 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 our 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.

Water Licenses

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements 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. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

Greenhouse Gases & Air Pollutants

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. A number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in Canada and the U.S.

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, 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 any 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.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2014 Canada 200 Climate Disclosure Leadership Index. We incorporate the potential costs of carbon, ranging from $15-$65 per tonne of CO_2, into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that may impose costly requirements. In 2007, 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 petroleum products they must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase RINs. In the future, the existing regulations could change the volume of renewable fuels required to be blended with refined products. This could create volatility in the price for RINs or an insufficient number of RINs being available to meet the requirements. Our financial condition, results of operations and cash flow could be materially adversely impacted.

Land Use, Habitat and Biodiversity

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 to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), issued under the ALSA. The LARP identifies 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. In 2013, we received financial compensation from the Government of Alberta related to some of our non-core oil sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on our business plan, our current operations at Foster Creek and Christina Lake or on any of our filed applications. 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.

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

The Government of Alberta has also commenced development of its North Saskatchewan Regional Plan ("NSRP"). This plan will apply to Cenovus's operations in central Alberta. The first phase of public consultation for the NSRP is complete. No assurance can be given that the NSRP won't materially impact operations or future operations in this region.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those 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 our 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 economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Our upstream and refining assets are grouped into 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 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 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. Estimates reflect market and regulatory conditions at December 31, 2014, which could differ significantly throughout the year or future period. 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

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For our upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating expenses. Recoverable amounts for Cenovus's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating expenses, transportation capacity and supply and demand conditions. 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.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

As at December 31, 2014, 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, 2014 by IQREs.

Crude Oil and Natural Gas Prices

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

	2015	2016	2017	2018	2019	Average Annual % Change to 2025
WTI (US$/barrel)	65.00	75.00	80.00	84.90	89.30	2.5%
WCS ($/barrel)	57.60	69.90	74.70	79.50	83.70	2.5%
AECO ($/Mcf)	3.50	4.00	4.25	4.50	4.70	4.1%

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. Changes in economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, 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 and as a result 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

We adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, we adopted, as required, amendments to International Accounting Standard 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. The adoption of IAS 32 did not impact the Consolidated Financial Statements.

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, 2015 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2014. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

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.

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption 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, 2014. 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, 2014.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2014. There have been no changes to ICFR during the year ended December 31, 2014 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.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, our CR approach and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We strive to never compromise the health or safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the CR policy includes reference to emergency response management, investment in efficiency projects, new technologies and research and support of the principles of the Universal Declaration of Human Rights.

We continue to review our CR reporting process, performance indicators and controls to ensure they align with our stakeholder expectations, our operations and our strategy. The CR report is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

We published our 2013 CR report in July 2014, which highlighted our investments in innovation and research, local and Aboriginal spending in our operating areas, advancements made in minimizing our environmental impacts, long-term agreements signed with Aboriginal communities, and our involvement with and investments in charities and non-profit organizations. Our CR policy and CR report are available on our website at cenovus.com.

In December 2014, we were named to the Canada 200 Climate Disclosure Leadership Index for the fifth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions.

In September 2014, our CR practices were recognized internationally with the inclusion of Cenovus in the Dow Jones Sustainability World Index for the third consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fifth consecutive year. The Dow Jones Sustainability Indices track the financial performance of the leading companies worldwide regarding CR performance.

In June 2014, we were named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the third year in a row and for the fourth consecutive year by Corporate Knights magazine as one of the 2014 Best 50 Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development.

In February 2014, we were named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the second year in a row. In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based international investment specialist in sustainability investing that publishes the Dow Jones Sustainability Index. Corporate Knights magazine also named Cenovus to their 2014 Global 100 Clean Capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland in January 2014.

These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

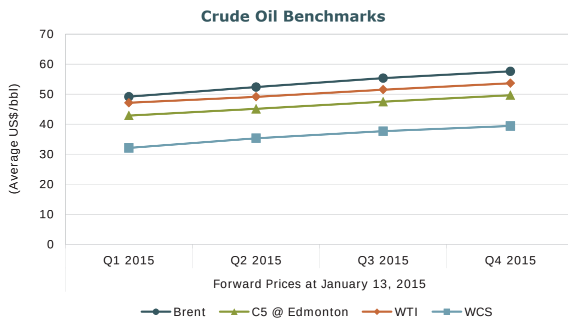
We expect 2015 to be a challenging time for our industry. Since December 2014, crude oil prices have continued to weaken and we anticipate prices may remain relatively low throughout 2015. Cenovus remains well positioned. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges in 2015. We continue to pursue our long-term strategy, though at a pace we believe is more in line with the current crude oil pricing environment. We have revised our 2015 budget, reducing our capital spending in order to preserve cash and maintain the strength of our balance sheet. For more information we direct our readers to review our news release dated January 28, 2015, which makes reference to our revised 2015 budget and our news release dated December 11, 2014, which includes our previously disclosed net asset value target. The news releases are available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

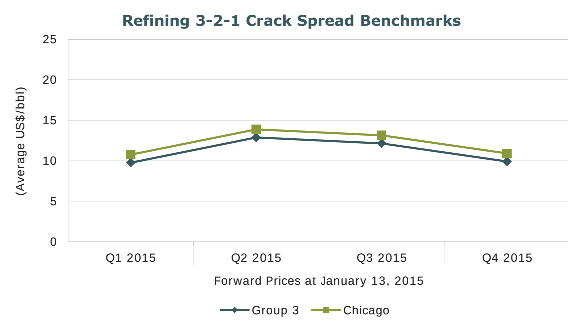
The following outlook commentary is focused on the next twelve months.

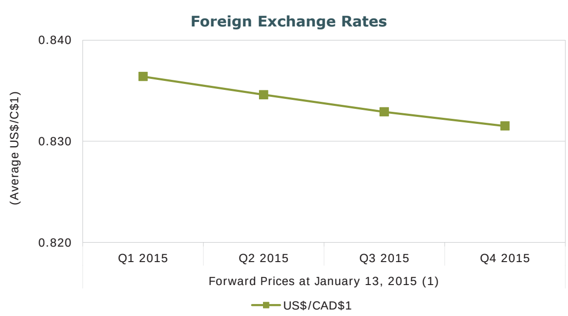
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the non-OPEC supply response to the current price environment and the pace of growth of the global economy. Overall, we expect Brent crude oil prices to decline as we enter the seasonally weak demand period in the spring which could result in shut-in of the least economic production as measured by variable costs. A reduction in global supply growth, combined with annual increases in demand growth and seasonal impacts in the last half of the year will help slightly improve prices for the remainder of the year as reflected in the forward curve. Most North American producers have announced significant reductions in capital spending which should slow supply growth in the coming quarters. However, we anticipate that potential supply reductions from global non-tight oil producers will not be as significant due to more stable production profiles and historically longer lead-times to bring on projects. The current low crude oil price environment also serves to help boost global economic momentum which, with the exception of the U.S., has been faced with mounting deflationary concerns and transitioning emerging markets. By mid-year, OPEC may reduce production and provide some support to prices if they see that action has been taken by the market which will enable OPEC to sustain market share. Longer term, low crude oil prices should push producers to reduce costs and improve efficiencies thereby resulting in sustained lower crude oil prices as compared to recent years. However, if OPEC continues to abandon its historic swing supplier role, price volatility will be significantly greater than historic norms;
- Overall, we expect the Brent-WTI differential to remain consistent with levels experienced at the end of 2014. A decline in crude oil supply growth, as discussed above, would decrease the impact that North American crude oil congestion could have on the differential; and
- The WTI-WCS differential will continue to be set by the marginal transportation cost to the U.S. Gulf Coast. With increased rail infrastructure planned over the coming year, along with incremental pipeline capacity, we expect higher levels of spare takeaway capacity from Alberta. Despite some volatility in the differential due to uncertainty around the timing of new infrastructure, we expect a narrower differential as compared to levels experienced at the end of 2014.







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

We expect average market crack spreads to remain relatively steady compared to the end of 2014 until an increase in seasonal demand in the U.S. results in an improvement in refined product prices.

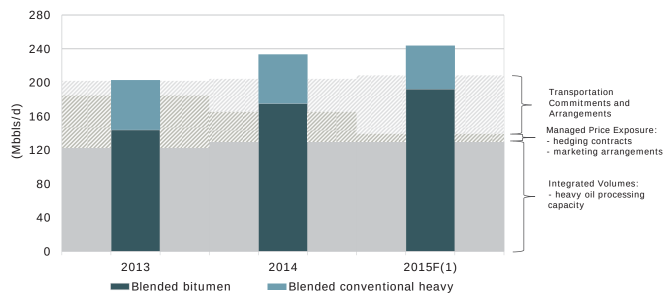
Natural gas prices are expected to decline throughout 2015 as compared to prices at the end of 2014. The inventory of drilled but uncompleted wells should keep supply growth strong even with a decline in industry activity.

The average foreign exchange forward price over the next four quarters is US$0.834/C$1. The recent Bank of Canada rate cut has acted to further depress the Canadian dollar against its U.S. counterpart. U.S. economic momentum and timing of key interest rate decisions, both in Canada and the U.S., will largely dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak over the next twelve months as compared to prices at the end of 2014, which would 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 prices, we mitigate our exposure to light/heavy price differentials through the following:

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

Protection Against Canadian Congestion



(1) Expected gross production capacity.

Key Priorities for 2015

Maintain Financial Resilience

We have strong producing assets, an integrated portfolio and a solid balance sheet which have positioned us well to face the challenges in 2015. Our capital planning process is flexible and spending can be reduced in response to commodity prices and other economic factors, so we can maintain our financial strength and resiliency, advance our strategy and not compromise our future plans. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2015.

Attack Cost Structures

We continue to challenge cost structures across the organization to maintain our track record of cost efficiency. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure and maximize the strengths of our business model. We have identified opportunities to achieve between $400 million and $500 million in anticipated annual operating and capital cost reductions in the years ahead.

As a result of the slowdown across the energy sector, we expect to see reductions in demand for labour, service and materials. This should create opportunities for us to make improvements in our cost structure.

Enable Market Access

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. This includes continued support for proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our 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.

During 2014, we entered into approximately $7 billion of new pipeline commitments (most of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth. In addition, we increased our rail takeaway capacity for crude oil to approximately 30,000 barrels per day.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

ADVISORY

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”, “plan”, “forecast” or “F”, “future”, “target”, “project”, “capacity”, “could”, “should”, “focus”, “goal”, “outlook”, “potential”, “may”, “strategy” or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future value or net asset value, projections for 2015 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 future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, dividend plans and strategy, including with respect to the dividend reinvestment plan, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact, future credit ratings 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 disclosed 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 from operations 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.

2015 guidance is based on an average diluted number of shares outstanding of approximately 760 million. It assumes: Brent US$53.50/bbl, WTI of US$50.50/bbl; Western Canadian Select of US$36.25/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.70/GJ; Chicago 3-2-1 crack spread of US$11.75/bbl; and an exchange rate of $0.83 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and 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; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; 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 heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; 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 our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient crude-by-rail or other alternate transportation; 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 year ended December 31, 2014, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Oil and Gas Information

The estimates of reserves, bitumen contingent resources and prospective resources estimates were prepared effective December 31, 2014 by our IQREs in accordance with 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*.

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 2014 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.

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, 2014, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

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

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
		GJ	Gigajoule

BOE	barrel of oil equivalent
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.

Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2014

(Canadian Dollars)

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 three 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, 2014. 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, 2014.

PricewaterhouseCoopers LLP, an independent firm of Chartered 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, 2014, as stated in their Auditor's Report dated February 11, 2015. PricewaterhouseCoopers LLP has provided such opinions.

(signed)

Brian C. Ferguson
President &
Chief Executive Officer
Cenovus Energy Inc.

(signed)

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

February 11, 2015

Independent Auditor's Report

To the Shareholders of Cenovus Energy Inc.

We have completed an integrated audit of Cenovus Energy Inc.'s 2014, 2013 and 2012 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits, are presented below.

Report on the Consolidated Financial Statements

We have audited the accompanying Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2014 and December 31, 2013 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the Consolidated Financial Statements.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of Cenovus Energy Inc. as at December 31, 2014 and December 31, 2013 and its financial performance and cash flows for each of the three years ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on Internal Control over Financial Reporting

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Management's Responsibility for Internal Control over Financial Reporting

Management is responsible 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.

Auditor's Responsibility

Our responsibility is to express an opinion on Cenovus Energy Inc.'s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Cenovus Energy Inc.'s internal control over financial reporting.

Definition of Internal Control over Financial Reporting

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.

Inherent Limitations

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.

Opinion

In our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014 based on criteria established in Internal Control – Integrated Framework (2013), issued by COSO.

(signed)

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada

February 11, 2015

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

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

	Notes	2014	2013	2012
Revenues	1			
Gross Sales		**20,107**	18,993	17,229
Less: Royalties		**465**	336	387
		19,642	18,657	16,842
Expenses	1			
Purchased Product		**10,955**	10,399	9,223
Transportation and Blending		**2,477**	2,074	1,798
Operating		**2,066**	1,798	1,667
Production and Mineral Taxes		**46**	35	37
(Gain) Loss on Risk Management	31	**(662)**	293	(393)
Depreciation, Depletion and Amortization	15,16	**1,946**	1,833	1,585
Goodwill Impairment	18	**497**	-	393
Exploration Expense	14	**86**	114	68
General and Administrative		**358**	349	350
Finance Costs	6	**445**	529	455
Interest Income	7	**(33)**	(96)	(109)
Foreign Exchange (Gain) Loss, Net	8	**411**	208	(20)
Research Costs		**15**	24	15
(Gain) Loss on Divestiture of Assets	16	**(156)**	1	-
Other (Income) Loss, Net		**(4)**	2	(5)
Earnings Before Income Tax		**1,195**	1,094	1,778
Income Tax Expense	9	**451**	432	783
Net Earnings		**744**	662	995
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		**(18)**	14	(4)
Items That May be Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		**-**	10	-
Foreign Currency Translation Adjustment		**215**	117	(24)
Total Other Comprehensive Income (Loss), Net of Tax		**197**	141	(28)
Comprehensive Income		**941**	803	967
Net Earnings Per Common Share	10			
Basic		**$0.98**	$0.88	$1.32
Diluted		**$0.98**	$0.87	$1.31

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	2014	2013
Assets			
Current Assets			
Cash and Cash Equivalents	11	**883**	2,452
Accounts Receivable and Accrued Revenues	12	**1,582**	1,874
Income Tax Receivable		**28**	15
Inventories	13	**1,224**	1,259
Risk Management	31	**478**	10
Current Assets		**4,195**	5,610
Exploration and Evaluation Assets	1,14	**1,625**	1,473
Property, Plant and Equipment, Net	1,15	**18,563**	17,334
Other Assets	17	**70**	68
Goodwill	1,18	**242**	739
Total Assets		**24,695**	25,224
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	19	**2,588**	2,937
Income Tax Payable		**357**	268
Current Portion of Partnership Contribution Payable	20	**-**	438
Risk Management	31	**12**	136
Current Liabilities		**2,957**	3,779
Long-Term Debt	21	**5,458**	4,997
Partnership Contribution Payable	20	**-**	1,087
Risk Management	31	**4**	3
Decommissioning Liabilities	22	**2,616**	2,370
Other Liabilities	23	**172**	180
Deferred Income Taxes	9	**3,302**	2,862
Total Liabilities		**14,509**	15,278
Shareholders' Equity		**10,186**	9,946
Total Liabilities and Shareholders' Equity		**24,695**	25,224
Commitments and Contingencies	34		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

(signed)

Michael A. Grandin
Director
Cenovus Energy Inc.

(signed)

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, 2011	3,780	4,107	1,400	97	9,384
Net Earnings	-	-	995	-	995
Other Comprehensive Income (Loss)	-	-	-	(28)	(28)
Total Comprehensive Income (Loss)	-	-	995	(28)	967
Common Shares Issued Under Stock Option Plans	49	-	-	-	49
Stock-Based Compensation Expense	-	47	-	-	47
Dividends on Common Shares	-	-	(665)	-	(665)
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**

(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	2014	2013	2012
Operating Activities				
Net Earnings		**744**	662	995
Depreciation, Depletion and Amortization	15	**1,946**	1,833	1,585
Goodwill Impairment	18	**497**	-	393
Exploration Expense	14	**86**	50	68
Deferred Income Taxes	9	**359**	244	474
Unrealized (Gain) Loss on Risk Management	31	**(596)**	415	(57)
Unrealized Foreign Exchange (Gain) Loss	8	**411**	40	(70)
(Gain) Loss on Divestiture of Assets	16	**(156)**	1	-
Unwinding of Discount on Decommissioning Liabilities	6,22	**120**	97	86
Other		**68**	267	169
		3,479	3,609	3,643
Net Change in Other Assets and Liabilities		**(135)**	(120)	(113)
Net Change in Non-Cash Working Capital		**182**	50	(110)
Cash From Operating Activities		**3,526**	3,539	3,420
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	14	**(279)**	(331)	(654)
Capital Expenditures – Property, Plant and Equipment	15	**(2,779)**	(2,938)	(2,795)
Proceeds From Divestiture of Assets	16	**276**	258	76
Net Change in Investments and Other	20	**(1,583)**	1,486	(13)
Net Change in Non-Cash Working Capital		**15**	6	50
Cash (Used in) Investing Activities		**(4,350)**	(1,519)	(3,336)
Net Cash Provided (Used) Before Financing Activities		**(824)**	2,020	84
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**(18)**	(8)	3
Issuance of U.S. Unsecured Notes	21	**-**	814	1,219
Repayment of U.S. Unsecured Notes	21	**-**	(825)	-
Proceeds on Issuance of Common Shares		**28**	28	37
Dividends Paid on Common Shares	10	**(805)**	(732)	(665)
Other		**(2)**	(3)	(2)
Cash From (Used in) Financing Activities		**(797)**	(726)	592
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**52**	(2)	(11)
Increase (Decrease) in Cash and Cash Equivalents		**(1,569)**	1,292	665
Cash and Cash Equivalents, Beginning of Year		**2,452**	1,160	495
Cash and Cash Equivalents, End of Year		**883**	2,452	1,160
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 the development, production and marketing of crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S.").

Cenovus is incorporated under the *Canada Business Corporations Act* and its shares are publicly traded 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 Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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. This segment also includes 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. 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.

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

For the years ended December 31,	Oil Sands 2014	Oil Sands 2013	Oil Sands 2012	Conventional 2014	Conventional 2013	Conventional 2012	Refining and Marketing 2014	Refining and Marketing 2013	Refining and Marketing 2012
Revenues									
Gross Sales	**5,036**	3,912	3,356	**3,225**	2,980	2,800	**12,658**	12,706	11,356
Less: Royalties	**236**	132	186	**229**	204	201	**-**	-	-
	4,800	3,780	3,170	**2,996**	2,776	2,599	**12,658**	12,706	11,356
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**11,767**	11,004	9,506
Transportation and Blending	**2,131**	1,749	1,501	**346**	325	297	**-**	-	-
Operating	**647**	555	426	**718**	708	662	**707**	540	581
Production and Mineral Taxes	**-**	-	-	**46**	35	37	**-**	-	-
(Gain) Loss on Risk Management	**(38)**	(37)	(64)	**(1)**	(104)	(268)	**(27)**	19	(4)
Operating Cash Flow	**2,060**	1,513	1,307	**1,887**	1,812	1,871	**211**	1,143	1,273
Depreciation, Depletion and Amortization	**625**	446	339	**1,082**	1,170	1,048	**156**	138	146
Goodwill Impairment	**-**	-	-	**497**	-	393	**-**	-	-
Exploration Expense	**4**	-	-	**82**	114	68	**-**	-	-
Segment Income	**1,431**	1,067	968	**226**	528	362	**55**	1,005	1,127

For the years ended December 31,	Corporate and Eliminations 2014	Corporate and Eliminations 2013	Corporate and Eliminations 2012	Consolidated 2014	Consolidated 2013	Consolidated 2012
Revenues						
Gross Sales	**(812)**	(605)	(283)	**20,107**	18,993	17,229
Less: Royalties	**-**	-	-	**465**	336	387
	(812)	(605)	(283)	**19,642**	18,657	16,842
Expenses						
Purchased Product	**(812)**	(605)	(283)	**10,955**	10,399	9,223
Transportation and Blending	**-**	-	-	**2,477**	2,074	1,798
Operating	**(6)**	(5)	(2)	**2,066**	1,798	1,667
Production and Mineral Taxes	**-**	-	-	**46**	35	37
(Gain) Loss on Risk Management	**(596)**	415	(57)	**(662)**	293	(393)
	602	(410)	59	**4,760**	4,058	4,510
Depreciation, Depletion and Amortization	**83**	79	52	**1,946**	1,833	1,585
Goodwill Impairment	**-**	-	-	**497**	-	393
Exploration Expense	**-**	-	-	**86**	114	68
Segment Income (Loss)	**519**	(489)	7	**2,231**	2,111	2,464
General and Administrative	**358**	349	350	**358**	349	350
Finance Costs	**445**	529	455	**445**	529	455
Interest Income	**(33)**	(96)	(109)	**(33)**	(96)	(109)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)	**411**	208	(20)
Research Costs	**15**	24	15	**15**	24	15
(Gain) Loss on Divestiture of Assets	**(156)**	1	-	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)	**(4)**	2	(5)
	1,036	1,017	686	**1,036**	1,017	686
Earnings Before Income Tax				**1,195**	1,094	1,778
Income Tax Expense				**451**	432	783
Net Earnings				**744**	662	995

B) Financial Results by Upstream Product

Crude Oil [1]

For the years ended December 31,	Oil Sands 2014	Oil Sands 2013	Oil Sands 2012	Conventional 2014	Conventional 2013	Conventional 2012	Total 2014	Total 2013	Total 2012
Revenues									
Gross Sales	**4,963**	3,850	3,307	**2,456**	2,373	2,289	**7,419**	6,223	5,596
Less: Royalties	**233**	131	186	**217**	196	195	**450**	327	381
	4,730	3,719	3,121	**2,239**	2,177	2,094	**6,969**	5,896	5,215
Expenses									
Transportation and Blending	**2,130**	1,748	1,499	**326**	305	278	**2,456**	2,053	1,777
Operating	**622**	531	401	**512**	495	441	**1,134**	1,026	842
Production and Mineral Taxes	**-**	-	-	**37**	32	34	**37**	32	34
(Gain) Loss on Risk Management	**(38)**	(33)	(46)	**4**	(43)	(39)	**(34)**	(76)	(85)
Operating Cash Flow	**2,016**	1,473	1,267	**1,360**	1,388	1,380	**3,376**	2,861	2,647

(1) *Includes NGLs.*

Natural Gas

For the years ended December 31,	Oil Sands 2014	Oil Sands 2013	Oil Sands 2012	Conventional 2014	Conventional 2013	Conventional 2012	Total 2014	Total 2013	Total 2012
Revenues									
Gross Sales	**67**	38	38	**744**	594	498	**811**	632	536
Less: Royalties	**3**	1	-	**12**	8	6	**15**	9	6
	64	37	38	**732**	586	492	**796**	623	530
Expenses									
Transportation and Blending	**1**	1	2	**20**	20	19	**21**	21	21
Operating	**18**	18	23	**200**	209	217	**218**	227	240
Production and Mineral Taxes	**-**	-	-	**9**	3	3	**9**	3	3
(Gain) Loss on Risk Management	**-**	(4)	(18)	**(5)**	(61)	(229)	**(5)**	(65)	(247)
Operating Cash Flow	**45**	22	31	**508**	415	482	**553**	437	513

Other

For the years ended December 31,	Oil Sands 2014	Oil Sands 2013	Oil Sands 2012	Conventional 2014	Conventional 2013	Conventional 2012	Total 2014	Total 2013	Total 2012
Revenues									
Gross Sales	**6**	24	11	**25**	13	13	**31**	37	24
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
	6	24	11	**25**	13	13	**31**	37	24
Expenses									
Transportation and Blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**7**	6	2	**6**	4	4	**13**	10	6
Production and Mineral Taxes	**-**	-	-	**-**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**(1)**	18	9	**19**	9	9	**18**	27	18

Total Upstream

For the years ended December 31,	Oil Sands 2014	Oil Sands 2013	Oil Sands 2012	Conventional 2014	Conventional 2013	Conventional 2012	Total 2014	Total 2013	Total 2012
Revenues									
Gross Sales	**5,036**	3,912	3,356	**3,225**	2,980	2,800	**8,261**	6,892	6,156
Less: Royalties	**236**	132	186	**229**	204	201	**465**	336	387
	4,800	3,780	3,170	**2,996**	2,776	2,599	**7,796**	6,556	5,769
Expenses									
Transportation and Blending	**2,131**	1,749	1,501	**346**	325	297	**2,477**	2,074	1,798
Operating	**647**	555	426	**718**	708	662	**1,365**	1,263	1,088
Production and Mineral Taxes	**-**	-	-	**46**	35	37	**46**	35	37
(Gain) Loss on Risk Management	**(38)**	(37)	(64)	**(1)**	(104)	(268)	**(39)**	(141)	(332)
Operating Cash Flow	**2,060**	1,513	1,307	**1,887**	1,812	1,871	**3,947**	3,325	3,178

C) Geographic Information

	Canada			United States			Consolidated		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**10,604**	8,943	8,069	**9,503**	10,050	9,160	**20,107**	18,993	17,229
Less: Royalties	**465**	336	387	**-**	-	-	**465**	336	387
	10,139	8,607	7,682	**9,503**	10,050	9,160	**19,642**	18,657	16,842
Expenses									
Purchased Product	**2,310**	2,022	1,884	**8,645**	8,377	7,339	**10,955**	10,399	9,223
Transportation and Blending	**2,477**	2,074	1,798	**-**	-	-	**2,477**	2,074	1,798
Operating	**1,387**	1,276	1,108	**679**	522	559	**2,066**	1,798	1,667
Production and Mineral Taxes	**46**	35	37	**-**	-	-	**46**	35	37
(Gain) Loss on Risk Management	**(625)**	275	(385)	**(37)**	18	(8)	**(662)**	293	(393)
	4,544	2,925	3,240	**216**	1,133	1,270	**4,760**	4,058	4,510
Depreciation, Depletion and Amortization	**1,790**	1,695	1,439	**156**	138	146	**1,946**	1,833	1,585
Goodwill Impairment	**497**	-	393	**-**	-	-	**497**	-	393
Exploration Expense	**86**	114	68	**-**	-	-	**86**	114	68
Segment Income	**2,171**	1,116	1,340	**60**	995	1,124	**2,231**	2,111	2,464

The Oil Sands and Conventional segments operate in Canada. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third-party purchases and sales of product, is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business. The Corporate and Eliminations segment is attributed to Canada, with the exception of the unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

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 $821 million (2013 – $926 million; 2012 – $671 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, 2014, Cenovus had three customers (2013 – three; 2012 – 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 $7,210 million, $2,668 million and $2,316 million, respectively (2013 – $7,032 million, $2,711 million and $1,799 million; 2012 – $3,928 million, $3,300 million and $2,839 million).

D) Joint Operations

A significant portion of the operating cash flows from the Oil Sands, and Refining and Marketing segments are derived through jointly controlled entities, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), respectively. These joint arrangements, in which Cenovus has a 50 percent ownership interest, are classified as joint operations and, as such, Cenovus recognizes its share of the assets, liabilities, revenues and expenses.

FCCL, which is involved in the development and production of crude oil in Canada, is jointly controlled with ConocoPhillips and operated by Cenovus. WRB has two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with and operated by Phillips 66. Cenovus's share of operating cash flow from FCCL and WRB for the year ended December 31, 2014 was $1,933 million and $214 million, respectively (2013 – $1,383 million and $1,144 million; 2012 – $1,188 million and $1,274 million).

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

By Segment

	E&E (1)		PP&E (2)	
As at December 31,	**2014**	2013	**2014**	2013
Oil Sands	**1,540**	1,328	**8,606**	7,401
Conventional	**85**	145	**6,038**	6,291
Refining and Marketing	**-**	-	**3,568**	3,269
Corporate and Eliminations	**-**	-	**351**	373
Consolidated	**1,625**	1,473	**18,563**	17,334

	Goodwill		Total Assets	
As at December 31,	**2014**	2013	**2014**	2013
Oil Sands	**242**	242	**11,024**	9,564
Conventional	**-**	497	**6,211**	7,220
Refining and Marketing	**-**	-	**5,520**	5,491
Corporate and Eliminations	**-**	-	**1,940**	2,949
Consolidated	**242**	739	**24,695**	25,224

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

By Geographic Region

	E&E		PP&E	
As at December 31,	**2014**	2013	**2014**	2013
Canada	**1,625**	1,473	**14,999**	14,066
United States	**-**	-	**3,564**	3,268
Consolidated	**1,625**	1,473	**18,563**	17,334

	Goodwill		Total Assets	
As at December 31,	**2014**	2013	**2014**	2013
Canada	**242**	739	**20,231**	20,548
United States	**-**	-	**4,464**	4,676
Consolidated	**242**	739	**24,695**	25,224

F) Capital Expenditures (1)

For the years ended December 31,	**2014**	2013	2012
Capital			
Oil Sands	**1,986**	1,885	1,697
Conventional	**840**	1,189	1,362
Refining and Marketing	**163**	107	118
Corporate	**62**	81	191
	3,051	3,262	3,368
Acquisition Capital			
Oil Sands (2)	**15**	27	69
Conventional	**3**	5	45
	3,069	3,294	3,482

(1) *Includes expenditures on PP&E and E&E.*
(2) *The 2014 acquisition capital includes the assumption of a decommissioning liability of $10 million (2013 – $nil; 2012 – $33 million).*

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 11, 2015.

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. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

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 at the average rate 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 and Comprehensive Income.

C) Revenue and Interest Income Recognition

Sales of Product

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.

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.

Interest Income

Interest income is recognized as the interest accrues using the effective interest method.

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) Production and Mineral Taxes

Costs paid to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is sold.

F) 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.

G) 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 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.
- 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 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.

H) Income Taxes

Income taxes comprise current and deferred taxes. Current and deferred 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.

I) Net Earnings per Share Amounts

Basic net earnings per common 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.

J) 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.

K) 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.

L) Assets (Disposal Groups) Held for Sale

Non-current assets or disposal groups are classified as held for sale when their carrying amount will be principally recovered through a sales transaction rather than through continued use and a sales transaction is highly probable. Assets held for sale are recorded at the lower of carrying value and fair value less costs of disposal.

M) 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 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.

Once technical feasibility and commercial viability have been established for a field/project/area, the carrying value of the E&E assets associated with that field/project/area is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources. If a field/project/area is determined not to be technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense in the period in which the determination occurs.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

N) Property, Plant and Equipment

Development and Production Assets

Development and production assets are stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net impairment losses. 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 commercial 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 forecast 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.

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 development and production assets are recognized in net earnings.

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 refining assets are stated at cost less accumulated depreciation and net impairment losses.

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. Maintenance and repairs are expensed as incurred.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they 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 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 25 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. Assets under construction are not subject to depreciation until they are available for use. 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.

O) Impairment

Non-Financial Assets

PP&E and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The recoverable amount is determined as the greater of an asset's or cash-generating unit's ("CGU") 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 based on the discounted after-tax cash flows of reserves and resources using forecast prices and costs, consistent with Cenovus's independent qualified reserves evaluators, and an evaluation of comparable asset transactions.

The impairment test is performed at the CGU for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses on PP&E are recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional DD&A and are separately disclosed. An impairment of E&E assets is recognized as exploration expense in the Consolidated Statements of Earnings and Comprehensive Income.

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. 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.

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.

P) Borrowing Costs

Borrowing costs are expensed as incurred unless there is a qualifying asset. Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized when a substantial period of time is required to make the asset ready for its intended use. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use.

Q) 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.

R) 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.

S) 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 and Comprehensive Income.

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 and refining facilities. 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. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.

T) 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.

U) Stock-Based Compensation

Cenovus has a number of cash and 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") and deferred share units ("DSUs").

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 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 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 and Deferred Share Units

PSUs 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 compensation costs over the vesting period. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

V) Financial Instruments

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 and Comprehensive Income.

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.

The Company’s consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets and long-term receivables. The Company’s financial liabilities include accounts payable and accrued liabilities, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

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.

Held to Maturity Investments

“Held-to-maturity investments” are measured at amortized cost using the effective interest method of amortization.

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.

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, the Partnership Contribution Payable, 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.

W) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2014.

X) Recent Accounting Pronouncements

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, 2015 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2014. The standards applicable to the Company are as follows and will be adopted on their respective effective dates:

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*" ("IAS 11"), IAS 18, "*Revenue*" ("IAS 18"), 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.

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption 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. CHANGE IN ACCOUNTING POLICIES

New and Amended Accounting Standards Adopted

The Company adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, the Company adopted, as required, amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. The adoption of IAS 32 did not impact the Consolidated Financial Statements.

5. 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, 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 economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

The Company's upstream and refining assets are grouped into 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 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 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

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating expenses. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating expenses, transportation capacity, and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

As at December 31, 2014, 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, 2014 by independent qualified reserves evaluators.

Crude Oil and Natural Gas Prices

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

	2015	2016	2017	2018	2019	Average Annual % Change to 2025
WTI (US$/barrel) (1)	65.00	75.00	80.00	84.90	89.30	2.5%
WCS ($/barrel) (2)	57.60	69.90	74.70	79.50	83.70	2.5%
AECO ($/Mcf) (3)	3.50	4.00	4.25	4.50	4.70	4.1%

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Assumes gas heating value of 1 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. Changes in economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, 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.

6. FINANCE COSTS

For the years ended December 31,	**2014**	2013	2012
Interest Expense – Short-Term Borrowings and Long-Term Debt	**285**	271	230
Premium on Redemption of Long-Term Debt	**-**	33	-
Interest Expense – Partnership Contribution Payable (Note 20)	**22**	98	118
Unwinding of Discount on Decommissioning Liabilities (Note 22)	**120**	97	86
Other	**18**	30	21
	445	529	455

7. INTEREST INCOME

For the years ended December 31,	2014	2013	2012
Interest Income – Partnership Contribution Receivable	-	(82)	(102)
Other	(33)	(14)	(7)
	(33)	(96)	(109)

In 2013, Cenovus, through its interest in FCCL, received the remaining principal and interest due under the Partnership Contribution Receivable.

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2014	2013	2012
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued from Canada	458	357	(69)
U.S. Dollar Partnership Contribution Receivable Issued from Canada	-	(305)	(15)
Other	(47)	(12)	14
Unrealized Foreign Exchange (Gain) Loss	411	40	(70)
Realized Foreign Exchange (Gain) Loss	-	168	50
	411	208	(20)

9. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	2014	2013	2012
Current Tax			
Canada	94	143	188
United States (1)	(2)	45	121
Total Current Tax	92	188	309
Deferred Tax	359	244	474
	451	432	783

(1) 2012 includes $68 million of withholding tax on a U.S. dividend.

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

For the years ended December 31,	2014	2013	2012
Earnings Before Income Tax	1,195	1,094	1,778
Canadian Statutory Rate	25.2%	25.2%	25.2%
Expected Income Tax	301	276	448
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	(43)	87	119
Non-Deductible Stock-Based Compensation	13	10	10
Foreign Exchange Gains (Losses) not Included in Net Earnings	(13)	19	14
Non-Taxable Capital (Gains) Losses	124	31	(7)
Derecognition (Recognition) of Capital Losses	(9)	15	(22)
Adjustments Arising From Prior Year Tax Filings	(16)	(13)	33
Withholding Tax on Foreign Dividend	-	-	68
Goodwill Impairment	125	-	99
Other	(31)	7	21
Total Tax	451	432	783
Effective Tax Rate	37.7%	39.5%	44.0%

The Canadian statutory tax rate remained unchanged at 25.2 percent for the years presented. The U.S. statutory tax rate has decreased to 38.1 percent in 2014 from 38.5 percent in 2013 and 2012 as a result of the allocation of taxable income to U.S. states the Company operates in.

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

As at December 31,	2014	2013
Net Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**296**	75
Deferred Tax Liabilities to be Settled After More Than 12 Months	**3,006**	2,787
	3,302	2,862

For the purposes of the preceding table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these 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 does 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	Net Foreign Exchange Gains	Risk Management	Other	Total
As at December 31, 2012	2,795	59	27	73	99	3,053
Charged/(Credited) to Earnings	145	29	(27)	(71)	49	125
Charged/(Credited) to OCI	60	-	-	-	4	64
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**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
As at December 31, 2012	(309)	(5)	(179)	(493)
Charged/(Credited) to Earnings	218	(30)	(69)	119
Charged/(Credited) to OCI	(13)	-	7	(6)
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)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2012	2,560
Charged/(Credited) to Earnings	244
Charged/(Credited) to OCI	58
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**

No deferred tax liability has been recognized as at December 31, 2014 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, 2014, the Company had temporary differences of $5,793 million (2013 – $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,	2014	2013
Canada	6,153	5,425
United States	958	1,083
	7,111	6,508

As at December 31, 2014, the above tax pools included $8 million (2013 – $5 million) of Canadian non-capital losses and $140 million (2013 – $238 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2014 tax pools are Canadian net capital losses totaling $593 million (2013 – $561 million), which are available for carry forward to reduce future capital gains. Of these losses, $559 million are unrecognized as a deferred income tax asset as at December 31, 2014 (2013 – $561 million). Recognition is dependent on the level of future capital gains.

10. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the years ended December 31,	2014	2013	2012
Net Earnings – Basic and Diluted ($ millions)	744	662	995
Basic – Weighted Average Number of Shares (millions)	756.9	755.9	755.6
Dilutive Effect of Cenovus TSARs	0.7	1.6	2.9
Dilutive Effect of Cenovus NSRs	-	-	-
Diluted – Weighted Average Number of Shares	757.6	757.5	758.5
Net Earnings Per Common Share ($)			
Basic	$0.98	$0.88	$1.32
Diluted	$0.98	$0.87	$1.31

B) Dividends Per Share

The Company paid dividends of $805 million or $1.0648 per share for the year ended December 31, 2014 (2013 – $732 million, $0.968 per share; 2012 – $665 million, $0.88 per share). The Cenovus Board of Directors declared a first quarter dividend of $0.2662 per share, payable on March 31, 2015, to common shareholders of record as of March 13, 2015.

11. CASH AND CASH EQUIVALENTS

As at December 31,	2014	2013
Cash	458	363
Short-Term Investments	425	2,089
	883	2,452

12. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	2014	2013
Accruals	**1,417**	1,585
Partner Advances	**44**	153
Prepaids and Deposits	**56**	55
Joint Operations Receivables	**18**	26
Other	**47**	55
	1,582	1,874

13. INVENTORIES

As at December 31,	2014	2013
Product		
Refining and Marketing	**972**	1,047
Oil Sands	**182**	156
Conventional	**28**	17
Parts and Supplies	**42**	39
	1,224	1,259

During the year ended December 31, 2014, approximately $15,065 million of produced and purchased inventory was recorded as an expense (2013 – $13,895 million; 2012 – $12,363 million).

As a result of a decline in refined product and crude oil prices, Cenovus recorded a write-down of its product inventory of $131 million from cost to net realizable value as at December 31, 2014.

14. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2012	1,285
Additions	331
Transfers to PP&E (Note 15)	(95)
Exploration Expense	(50)
Divestitures	(17)
Change in Decommissioning Liabilities	19
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E (Note 15)	(53)
Exploration Expense	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
As at December 31, 2014	**1,625**

E&E assets consist of the Company's evaluation projects which are pending determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the year ended December 31, 2014 include $51 million of internal costs directly related to the evaluation of these projects (2013 – $60 million). No borrowing costs or costs classified as general and administrative expenses have been capitalized during the year ended December 31, 2014 (2013 – $nil).

For the year ended December 31, 2014, $53 million of E&E assets were transferred to PP&E – development and production assets following the determination of technical feasibility and commercial viability of the projects (2013 – $95 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recorded in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2014, $82 million of previously capitalized E&E costs related to exploration assets within the Northern Alberta CGU 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.

15. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2012	27,003	238	3,399	767	31,407
Additions	2,702	48	106	82	2,938
Transfers from E&E Assets (Note 14)	95	-	-	-	95
Transfers to Assets Held for Sale	(450)	-	-	-	(450)
Change in Decommissioning Liabilities	40	-	(1)	-	39
Exchange Rate Movements and Other	-	-	150	-	150
As at December 31, 2013	29,390	286	3,654	849	34,179
Additions [2]	2,522	43	162	63	2,790
Transfers from E&E Assets (Note 14)	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**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2012	14,390	158	311	396	15,255
Depreciation, Depletion and Amortization	1,522	35	138	79	1,774
Transfers to Assets Held for Sale	(180)	-	-	-	(180)
Impairment Losses	59	-	-	-	59
Exchange Rate Movements and Other	-	-	(63)	-	(63)
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	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**
CARRYING VALUE					
As at December 31, 2012	12,613	80	3,088	371	16,152
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**

(1) Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.
(2) 2014 asset acquisition includes the assumption of a decommissioning liability of $10 million.

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $216 million (2013 – $204 million). All of the Company's development and production assets are located within Canada. No borrowing costs or costs classified as general and administrative expenses have been capitalized during the year ended December 31, 2014 (2013 – $nil).

PP&E includes the following amounts in respect of assets under construction and are not subject to DD&A:

As at December 31,	**2014**	2013
Development and Production	**478**	225
Refining Equipment	**159**	97
	637	322

Impairment

The impairment of PP&E and any subsequent reversal of such impairment losses are recorded in DD&A in the Consolidated Statements of Earnings and Comprehensive Income.

DD&A expense includes impairment losses as follows:

For the years ended December 31,	**2014**	2013	2012
Development and Production	**65**	59	-
Refining Equipment	**-**	-	-
	65	59	-

In the fourth quarter of 2014, the Company impaired equipment for $52 million. The Company does not have future plans for the equipment and does not believe it will recover the carrying amount through a sale. The asset has been written down to fair value less costs of disposal. In the second quarter of 2014, a minor natural gas property was shut-in and abandonment commenced. These impairments have been recorded in DD&A 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 DD&A in the Conventional segment.

16. DIVESTITURES

In the third quarter of 2014, the Company completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million. A gain of $137 million was recorded on the sale. These assets, related liabilities and results of operations were reported in the Conventional segment.

In the second quarter of 2014, the Company 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. The Company also completed the sale of certain non-core properties and recorded a total gain of $4 million. These assets, related liabilities 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, related liabilities 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.

17. OTHER ASSETS

As at December 31,	**2014**	2013
Equity Investments	**36**	32
Long-Term Receivables	**7**	11
Prepaids	**7**	7
Other	**20**	18
	70	68

18. GOODWILL

As at December 31,	2014	2013
Carrying Value, Beginning of Year	**739**	739
Impairment	**(497)**	-
Carrying Value, End of Year	**242**	739

There were no additions to goodwill during the years ended December 31, 2014 and 2013.

Impairment Test for CGUs Containing Goodwill

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. The carrying amount of goodwill allocated to the Company's exploration and production CGUs is:

As at December 31,	2014	2013
Primrose (Foster Creek)	**242**	242
Northern Alberta	**-**	497
	242	739

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 and Comprehensive Income. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage. 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 forecast 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.

There were no impairments of goodwill in the year ended December 31, 2013 (2012 – $393 million).

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 impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Price Estimates
Impairment of Goodwill	**-**	**-**
Impairment of PP&E	**134**	**419**

19. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	2014	2013
Accruals	**2,057**	2,317
Partner Advances	**218**	233
Trade	**51**	102
Employee Long-Term Incentives	**91**	116
Interest	**61**	82
Other	**110**	87
	2,588	2,937

20. PARTNERSHIP CONTRIBUTION PAYABLE

Through its interests in WRB, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Payable, which arose when Cenovus became a 50 percent partner of an integrated North American oil business. On March 28, 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.

21. LONG-TERM DEBT

As at December 31,		**2014**	2013
Revolving Term Debt [1]	A	**-**	-
U.S. Dollar Denominated Unsecured Notes	B	**5,510**	5,052
Total Debt Principal	C	**5,510**	5,052
Debt Discounts and Transaction Costs	D	**(52)**	(55)
		5,458	4,997

(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, 2014 was 5.0 percent (2013 – 5.2 percent).

A) Revolving Term Debt

As at December 31, 2014, Cenovus had in place a committed credit facility in the amount of $3.0 billion or the equivalent amount in U.S. dollars. The committed credit facility was renegotiated in November 2014 to extend the maturity date to November 30, 2018. The maturity date is extendable from time to time, for a period of up to four years 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, 2014, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2013 – $nil).

B) Unsecured Notes

Unsecured notes are composed of:

As at	US$ Principal Amount	**December 31, 2014**	December 31, 2013
5.70% due October 15, 2019	1,300	**1,508**	1,382
3.00% due August 15, 2022	500	**580**	532
3.80% due September 15, 2023	450	**522**	479
6.75% due November 15, 2039	1,400	**1,624**	1,489
4.45% due September 15, 2042	750	**870**	798
5.20% due September 15, 2043	350	**406**	372
		5,510	5,052

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, 2014, 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, 2014, 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, 2014, 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**
2015	-	-	**-**
2016	-	-	**-**
2017	-	-	**-**
2018	-	-	**-**
2019	1,300	-	**1,508**
Thereafter	3,450	-	**4,002**
	4,750	-	**5,510**

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 2014, additional transaction costs of $2 million were recorded (2013 – $15 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 and refining facilities. The aggregate carrying amount of the obligation is:

As at December 31,	**2014**	2013
Decommissioning Liabilities, Beginning of Year	**2,370**	2,315
Liabilities Incurred	**48**	45
Liabilities Settled	**(93)**	(76)
Liabilities Divested	**(60)**	-
Transfers and Reclassifications	**(9)**	(26)
Change in Estimated Future Cash Flows	**115**	414
Change in Discount Rate	**122**	(401)
Unwinding of Discount on Decommissioning Liabilities	**120**	97
Foreign Currency Translation	**3**	2
Decommissioning Liabilities, End of Year	**2,616**	2,370

The undiscounted amount of estimated future cash flows required to settle the obligation is $8,333 million (December 31, 2013 – $7,471 million), which has been discounted using a credit-adjusted risk-free rate of 4.9 percent (December 31, 2013 – 5.2 percent). 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 $50 million to $100 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from accelerated timing of forecast abandonment and reclamation spending, and higher cost estimates.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2014		2013	
As at December 31,	**Credit–Adjusted Risk-Free Rate**	**Inflation Rate**	Credit–Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(419)**	**574**	(345)	472
One Percent Decrease	**562**	**(433)**	461	(357)

23. OTHER LIABILITIES

As at December 31,	2014	2013
Deferred Revenues	-	25
Employee Long-Term Incentives	57	67
Pension and OPEB (Note 24)	84	51
Other	31	37
	172	180

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, 2013 and the next required actuarial valuation will be as at December 31, 2016.

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,	2014	2013	2014	2013
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	148	134	18	20
Current Service Costs	15	17	2	2
Interest Costs (1)	7	6	1	1
Benefits Paid	(3)	(5)	-	-
Plan Participant Contributions	3	2	-	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	-	1	-	-
(Gains) Losses from Changes in Demographic Assumptions	(1)	12	-	(1)
(Gains) Losses from Changes in Financial Assumptions	31	(19)	2	(4)
Defined Benefit Obligation, End of Year	200	148	23	18
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	115	94	-	-
Employer Contributions	12	15	-	-
Plan Participant Contributions	3	2	-	-
Benefits Paid	(3)	(5)	-	-
Interest Income (1)	4	2	-	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	8	7	-	-
Fair Value of Plan Assets, End of Year	139	115	-	-
Pension and Other Post-Employment Benefit (Liability) (2)	(61)	(33)	(23)	(18)

(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 17 years and 13 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Defined Benefit Plan Cost:						
Current Service Costs	**15**	17	10	**2**	2	2
Past Service Costs (1)	**-**	-	18	**-**	-	-
Net Interest Costs	**3**	4	1	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(8)**	(7)	(1)	**-**	-	-
(Gains) Losses from Experience Adjustments	**-**	1	3	**-**	-	1
(Gains) Losses from Changes in Demographic Assumptions	**(1)**	12	-	**-**	(1)	(1)
(Gains) Losses from Changes in Financial Assumptions	**31**	(19)	4	**2**	(4)	(2)
Defined Benefit Plan Cost (Gain)	**40**	8	35	**5**	(2)	1
Defined Contribution Plan Cost	**30**	27	25	**-**	-	-
Total Plan Cost	**70**	35	60	**5**	(2)	1

(1) Past service costs for eligible employees meeting certain criteria who elected to convert from the defined contribution pension to defined benefit pension.

Pension costs are recorded in operating and general and administrative expenses, and PP&E and E&E assets, corresponding to where the associated salaries and wages of the employees rendering the service are recorded.

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, 2014**	December 31, 2013
Equity Securities		
Equity Funds and Balanced Funds	**75**	67
Other	**9**	8
Bond Funds	**36**	25
Non-Invested Assets	**15**	12
Real Estate	**4**	3
	139	115

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, 2013, 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, 2015 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,	**2014**	2013	2012	**2014**	2013	2012
Discount Rate	**3.75%**	4.75%	4.00%	**3.75%**	4.75%	4.00%
Future Salary Growth Rate	**4.32%**	4.39%	4.39%	**5.65%**	5.65%	5.77%
Average Longevity (Years)	**88.3**	88.5	86.1	**88.3**	88.5	86.1
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	7.00%	8.00%

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 as at December 31, 2014 is shown below.

	One Percentage Point Increase	One Percentage Point Decrease
Discount Rate	**(34)**	**43**
Future Salary Growth Rate	**4**	**(4)**
Health Care Cost Trend Rate	**2**	**(2)**
Future Mortality Rate (Years)	**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, subject to certain conditions, an unlimited number of first preferred and second preferred 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

	2014		2013	
As at December 31,	Number of Common Shares (Thousands)	Amount	Number of Common Shares (Thousands)	Amount
Outstanding, Beginning of Year	756,046	3,857	755,843	3,829
Common Shares Issued Under Stock Option Plans	1,057	32	970	31
Common Shares Cancelled	-	-	(767)	(3)
Outstanding, End of Year	**757,103**	**3,889**	756,046	3,857

During 2013, the Company cancelled 767,327 common shares. The common shares were held in reserve for un-exchanged shares of Alberta Energy Company Ltd., pursuant to the merger of Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002 ("AEC Merger"), in which Encana Corporation ("Encana") was formed. Due to the plan of arrangement ("Arrangement"), whereby Encana was split on December 1, 2009 into two independent energy companies, Encana and Cenovus, common shares of the Company were held in reserve until the tenth anniversary of the AEC Merger.

There were no preferred shares outstanding as at December 31, 2014 (2013 – nil).

As at December 31, 2014, there were 13 million (2013 – 24 million) common shares available for future issuance under stock option plans.

The Company has a dividend reinvestment plan ("DRIP"). Under the DRIP, holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury or purchased on the market.

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana under the Arrangement into two independent energy companies, Encana and Cenovus. In addition, paid in surplus includes compensation expense related to the Company's NSRs discussed in Note 27A).

	Pre-Arrangement Earnings	Stock-Based Compensation	Total
As at December 31, 2012	4,083	71	4,154
Stock-Based Compensation Expense	-	62	62
Common Shares Cancelled	3	-	3
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**

26. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at December 31, 2014	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
Balance, Beginning of Year	**(12)**	**212**	**10**	**210**
Other Comprehensive Income (Loss), Before Tax	**(24)**	**215**	**-**	**191**
Income Tax	**6**	**-**	**-**	**6**
Balance, End of Year	**(30)**	**427**	**10**	**407**

As at December 31, 2013	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
Balance, Beginning of Year	(26)	95	-	69
Other Comprehensive Income (Loss), Before Tax	18	117	13	148
Income Tax	(4)	-	(3)	(7)
Balance, End of Year	(12)	212	10	210

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 granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 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.

As at December 31, 2014	**Issued**	**Term** (Years)	**Weighted Average Remaining Contractual Life** (Years)	**Weighted Average Exercise Price** ($)	**Closing Share Price** ($)	**Number of Units Outstanding** (Thousands)
NSRs	On or After February 24, 2011	**7**	**5.13**	**32.63**	**23.97**	**40,549**
TSARs	Prior to February 17, 2010	**5**	**0.07**	**25.58**	**23.97**	**21**
TSARs	On or After February 17, 2010	**7**	**2.20**	**26.72**	**23.97**	**3,841**

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2014 was $4.70 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	**1.62%**
Expected Dividend Yield	**3.18%**
Expected Volatility [1]	**25.80%**
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, 2014	Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**26,315**	**35.26**
Granted	**16,307**	**28.59**
Exercised	**(125)**	**32.24**
Forfeited	**(1,948)**	**34.31**
Outstanding, End of Year	**40,549**	**32.63**
Exercisable, End of Year	**13,439**	**36.18**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $34.06.

	Outstanding NSRs		
As at December 31, 2014 Range of Exercise Price ($)	Number of NSRs (Thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 24.99	**55**	**6.94**	**23.81**
25.00 to 29.99	**15,181**	**6.14**	**28.39**
30.00 to 34.99	**13,564**	**5.17**	**32.60**
35.00 to 39.99	**11,749**	**3.79**	**38.18**
	40,549	**5.13**	**32.63**

	Exercisable NSRs	
As at December 31, 2014 Range of Exercise Price ($)	Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
20.00 to 24.99	**-**	**-**
25.00 to 29.99	**85**	**29.32**
30.00 to 34.99	**4,515**	**32.66**
35.00 to 39.99	**8,839**	**38.04**
	13,439	**36.18**

TSARs

The Company has recorded a liability of $8 million as at December 31, 2014 (December 31, 2013 – $33 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period-end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.43%**
Expected Dividend Yield	**3.51%**
Expected Volatility (1)	**26.52%**
Cenovus's Common Share Price	**23.97**

(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, 2014 was $nil (December 31, 2013 – $27 million).

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

As at December 31, 2014	Number of TSARs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	7,086	26.56
Exercised for Cash Payment	(2,106)	26.34
Exercised as Options for Common Shares	(1,044)	26.38
Forfeited	(13)	28.66
Expired	(61)	26.38
Outstanding, End of Year	3,862	26.72
Exercisable, End of Year	3,862	26.72

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $30.14.

	Outstanding TSARs		
As at December 31, 2014 Range of Exercise Price ($)	Number of TSARs (Thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	3,703	2.12	26.46
30.00 to 39.99	159	2.98	32.86
	3,862	2.16	26.72

	Exercisable TSARs	
As at December 31, 2014 Range of Exercise Price ($)	Number of TSARs (Thousands)	Weighted Average Exercise Price ($)
20.00 to 29.99	3,703	26.46
30.00 to 39.99	159	32.86
	3,862	26.72

The closing price of Cenovus's common shares on the TSX as at December 31, 2014 was $23.97.

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 $109 million as at December 31, 2014 (2013 – $103 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares as at December 31, 2014. The intrinsic value of vested PSUs was $nil as at December 31, 2014 (2013 – $nil) as PSUs are paid out upon vesting.

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

As at December 31, 2014	Number of PSUs (Thousands)
Outstanding, Beginning of Year	**5,785**
Granted	**3,012**
Vested and Paid Out	**(1,625)**
Cancelled	**(328)**
Units in Lieu of Dividends	**255**
Outstanding, End of Year	**7,099**

C) 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 $31 million as at December 31, 2014 (2013 – $36 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares as at December 31, 2014. 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, 2014	Number of DSUs (Thousands)
Outstanding, Beginning of Year	**1,192**
Granted to Directors	**57**
Granted From Annual Bonus Awards	**7**
Units in Lieu of Dividends	**46**
Redeemed	**(5)**
Outstanding, End of Year	**1,297**

D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses in the Consolidated Statements of Earnings and Comprehensive Income:

For the years ended December 31,	**2014**	2013	2012
NSRs	**41**	35	27
TSARs	**(10)**	(16)	(1)
PSUs	**34**	32	46
DSUs	**(5)**	-	3
Total Stock-Based Compensation Expense (Recovery)	**60**	51	75

28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2014	2013	2012
Salaries, Bonuses and Other Short-Term Employee Benefits	550	494	441
Defined Contribution Pension Plan	18	17	14
Defined Benefit Pension Plan and OPEB	14	15	20
Stock-Based Compensation (Note 27)	60	51	75
	642	577	550

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,	2014	2013	2012
Salaries, Director Fees and Short-Term Benefits	29	31	27
Post-Employment Benefits	4	4	7
Stock-Based Compensation	20	24	35
	53	59	69

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 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 excluding any amounts with respect to the Partnership Contribution Payable. 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.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at December 31,	2014	2013
Long-Term Debt	5,458	4,997
Shareholders' Equity	10,186	9,946
Capitalization	15,644	14,943
Debt to Capitalization	35%	33%

Cenovus continues to target a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times over the long-term.

As at December 31,	2014	2013	2012
Debt	**5,458**	4,997	4,679
Net Earnings	**744**	662	995
Add (Deduct):			
Finance Costs	**445**	529	455
Interest Income	**(33)**	(96)	(109)
Income Tax Expense	**451**	432	783
Depreciation, Depletion and Amortization	**1,946**	1,833	1,585
Goodwill Impairment	**497**	-	393
E&E Impairment	**86**	50	68
Unrealized (Gain) Loss on Risk Management	**(596)**	415	(57)
Foreign Exchange (Gain) Loss, Net	**411**	208	(20)
(Gain) Loss on Divestitures of Assets	**(156)**	1	-
Other (Income) Loss, Net	**(4)**	2	(5)
Adjusted EBITDA	**3,791**	4,036	4,088
Debt to Adjusted EBITDA	**1.4x**	1.2x	1.1x

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 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. It is Cenovus's intention to maintain investment grade credit ratings.

As at December 31, 2014, Cenovus had $3.0 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.

As at December 31, 2014, 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, Partnership Contribution Payable, risk management assets and liabilities, 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 the Partnership Contribution Payable and 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, 2014, the carrying value of Cenovus's long-term debt was $5,458 million and the fair value was $5,726 million (2013 carrying value – $4,997 million, fair value – $5,388 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. When fair value cannot be reliably measured, these assets are carried at cost. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

As at December 31,	2014	2013
Fair Value, Beginning of Year	**32**	14
Acquisition of Investments	**4**	5
Reclassification of Equity Investments	**(4)**	-
Change in Fair Value (1)	**-**	13
Fair Value, End of Year	**32**	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, natural gas and power purchase contracts. Crude oil 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, 2014 range from $33.50 to $54.75 per Megawatt Hour.

Summary of Unrealized Risk Management Positions

	December 31, 2014			December 31, 2013		
	Risk Management			Risk Management		
As at	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**423**	**7**	**416**	10	136	(126)
Natural Gas	**55**	**-**	**55**	-	-	-
Power	**-**	**9**	**(9)**	-	3	(3)
Total Fair Value	**478**	**16**	**462**	10	139	(129)

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

As at December 31,	2014	2013
Prices Sourced From Observable Data or Market Corroboration (Level 2)	**471**	(126)
Prices Determined From Unobservable Inputs (Level 3)	**(9)**	(3)
	462	(129)

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:

	2014	2013
Fair Value of Contracts, Beginning of Year	**(129)**	270
Fair Value of Contracts Realized During the Year (1)	**(66)**	(122)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year (1)	**662**	(293)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(5)**	16
Fair Value of Contracts, End of Year	**462**	(129)

(1) Includes a realized gain of $4 million and a decrease in fair value of $10 million related to the power contracts.

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:

	December 31, 2014			December 31, 2013		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**479**	**17**	**462**	16	145	(129)
Amount Offset	**(1)**	**(1)**	**-**	(6)	(6)	-
Net Amount per Consolidated Financial Statements	**478**	**16**	**462**	10	139	(129)

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, 2014, $12 million (2013 – $10 million) was pledged as collateral, of which $7 million (2013 – $5 million) could have been withdrawn.

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

For the years ended December 31,	**2014**	2013	2012
Realized (Gain) Loss [1]	**(66)**	(122)	(336)
Unrealized (Gain) Loss [2]	**(596)**	415	(57)
(Gain) Loss on Risk Management	**(662)**	293	(393)

(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 future 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 and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the AECO 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 Commodity Price Positions as at December 31, 2014

As at December 31, 2014	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	18,000 bbls/d	2015	$113.75/bbl	**269**
Brent Fixed Price	1,000 bbls/d	January – June 2015	$100.25/bbl	**5**
Brent Fixed Price	6,000 bbls/d	January – June 2015	US$65.03/bbl	**6**
WCS Differential (1)	5,000 bbls/d	January – June 2015	US$(19.85)/bbl	**(2)**
Brent Collars	10,000 bbls/d	2015	$105.25 – $123.57/bbl	**121**
Other Financial Positions (2)				**17**
Crude Oil Fair Value Position				**416**
Natural Gas Contracts				
Fixed Price Contracts				
AECO Fixed Price	149 MMcf/d	2015	$3.86/Mcf	**55**
Natural Gas Fair Value Position				**55**
Power Purchase Contracts				
Power Fair Value Position				**(9)**

(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.

Commodity 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, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

Risk Management Positions in Place as at December 31, 2014

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	**(145)**	**146**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	**5**	**(5)**
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)**

Risk Management Positions in Place as at December 31, 2013

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(200)	200
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	31	(31)
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	-	-
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)

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 8, 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, 2014, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2013 – US$4,750 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2013 – US$nil). In respect of these financial instruments, the impact of a $0.01 change 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,	**2014**	2013	2012
$0.01 Increase in Foreign Exchange Rate	**48**	48	30
$0.01 Decrease in Foreign Exchange Rate	**(48)**	(48)	(30)

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.

As at December 31, 2014, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2013 – $nil; 2012 – $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, 2014 and 2013, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2014, 91 percent (2013 – 94 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, 2014, Cenovus had two counterparties (2013 – four 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. 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. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

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, commercial paper and availability under its shelf prospectuses. As at December 31, 2014, Cenovus had $3.0 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:

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**

2013	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,937	-	-	-	2,937
Risk Management Liabilities (1)	136	3	-	-	139
Long-Term Debt (2)	271	537	537	8,732	10,077
Partnership Contribution Payable (2)	520	1,040	130	-	1,690
Other (2)	-	6	2	4	12

(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,	2014	2013	2012
Interest Paid	**335**	409	342
Interest Received	**33**	119	113
Income Taxes Paid	**46**	133	304

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:

2014	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Pipeline Transportation (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**

2013	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Pipeline Transportation (1)	377	554	647	807	1,284	17,512	21,181
Operating Leases (Building Leases)	119	119	117	118	159	2,950	3,582
Product Purchases	98	20	7	-	-	-	125
Capital Commitments	52	36	30	9	21	27	175
Other Long-Term Commitments	50	40	21	17	12	116	256
Total Payments (2)	696	769	822	951	1,476	20,605	25,319
Fixed Price Product Sales	52	54	56	3	-	-	165

(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.

As at December 31, 2014, there were outstanding letters of credit aggregating $74 million issued as security for performance under certain contracts (2013 – $78 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 $2,616 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, 2014

(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 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 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, 2014 no major discovery or other favourable or unfavourable event is believed to have caused a material change in the proved or proved developed reserves as of that date.

The reserves data contained therein is dated February 11, 2015 with an effective date of December 31, 2014.

OIL AND GAS RESERVE INFORMATION

All of Cenovus's reserves are located in Canada, primarily within the provinces of Alberta and Saskatchewan.

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)]
2013			
Beginning of year	1,334	255	756
Revisions and improved recovery	53	(2)	214
Extensions and discoveries	103	29	21
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	(5)	-
Production	(35)	(26)	(196)
End of year	1,455	251	795
Developed	169	199	791
Undeveloped	1,286	52	4
Total	1,455	251	795
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**

(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)
2014	**95.55**	**84.27**	**97.60**	**4.34**	**4.63**
2013	96.70	74.04	92.16	3.67	3.14

(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)	**2014**	2013
Future cash inflows	**122,882**	96,160
Less future:		
Production costs	**41,292**	34,161
Development costs	**15,643**	14,242
Decommissioning liability payments	**960**	900
Income taxes	**14,935**	10,654
Future net cash flows	**50,052**	36,203
Less 10 percent annual discount for estimated timing of cash flows	**31,065**	22,211
Discounted future net cash flows	**18,987**	13,992

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	**2014**	2013
Balance, beginning of year	**13,992**	14,689
Changes resulting from:		
Sales of oil and gas produced during the period	**(3,947)**	(3,325)
Extensions, discoveries and improved recovery, net of related costs	**1,498**	1,341
Purchases of proved reserves in place	**4**	-
Sales of proved reserves in place	**(134)**	(46)
Net change in prices and production costs	**6,414**	(2,592)
Revisions to quantity estimates	**361**	852
Accretion of discount	**1,809**	1,911
Previously estimated development costs incurred net of change in future development costs	**279**	643
Other	**33**	198
Net change in income taxes	**(1,322)**	321
Balance, end of year	**18,987**	13,992

OTHER FINANCIAL INFORMATION

Results of Operations

($ millions)	**2014**	2013
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	**4,546**	4,018
Intersegment sales	**812**	605
	5,358	4,623
Less:		
Operating costs, production and mineral taxes, and accretion of decommissioning liabilities	**1,529**	1,393
Depreciation, depletion and amortization	**86**	1,616
Goodwill impairment	**497**	-
Exploration expense	**1,707**	114
Operating income	**1,539**	1,500
Income taxes	**513**	394
Results of operations	**1,026**	1,106

Capitalized Costs

($ millions)	**2014**	2013
Proved oil and gas properties	**32,030**	29,676
Unproved oil and gas properties (1)	**1,625**	1,473
Total capital cost	**33,655**	31,149
Accumulated depreciation, depletion and amortization	**17,386**	15,984
Net capitalized costs	**16,269**	15,165

(1) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($ millions)	**2014**	2013
Acquisitions		
Unproved	**16**	32
Proved	**2**	-
Total acquisitions	**18**	32
Exploration costs	**159**	264
Development costs	**2,623**	2,763
Total costs incurred	**2,800**	3,059

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, 2014, 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, 2014, 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 "Independent Auditor's Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2014, 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, 2014, 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: Kerry D. Dyte, Executive Vice-President, General Counsel & Corporate Secretary, Cenovus Energy Inc., 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6. Alternatively, requests for a copy of the Code may be made by contacting the registrant's Corporate Secretarial Department at (403) 766-2000 (Fax: (403) 766-7600). 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. During fiscal year 2014, the board of directors approved amendments to the Code that enhanced the anti-corruption provisions of the Code, added new content to reinforce the registrant's focus on safety, and clarified provisions of the Code relating to political activities, lobbying activities and acquisition and supply of goods and services.

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, 2014, filed as part of this annual report on Form 40-F.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading "Audit Committee Information – Pre-Approval Policies and Procedures" in the registrant's Annual Information Form for the fiscal year ended December 31, 2014, filed as part of this annual report on Form 40-F.

Off-Balance Sheet Arrangements.

The registrant does not have any off-balance sheet arrangements 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, 2014, 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, 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 13, 2015

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	Amended Code of Business Conduct & Ethics

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 13, 2015

/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 13, 2015

/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, 2014, 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 13, 2015

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, 2014, 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 13, 2015

By: /s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer

Exhibit 99.5

CONSENT OF PRICEWATERHOUSECOOPERS LLP

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2014 of Cenovus Energy Inc. of our report dated February 11, 2015, relating to the Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2014 and December 31, 2013 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years in the period ended December 31, 2014 and the related notes and to the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as at December 31, 2014, 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. 333-166419), and Form F-10 (File No. 333-196696) of Cenovus Energy Inc. of our report dated February 11, 2015 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 13, 2015

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, 2014, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2014, 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, 2014 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), 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 13, 2015

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, 2014, 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, 2014 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), 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 13, 2015

Code of Business Conduct & Ethics

This Code of Business Conduct & Ethics reflects Cenovus's commitment to conducting our business ethically, legally and safely while we pursue progressive and innovative approaches to developing energy resources. At Cenovus, we can be trusted to do what we say. We are a company that conducts its business with respect. This Code will be used to identify and manage ethical situations and to provide guidance in making ethical business decisions so that our staff can fulfill these commitments.

Compliance with Laws and Regulations

As employees, contractors and directors, we comply with the laws, rules and regulations of Canada, the United States and any other countries in which Cenovus operates. We comply with the requirements of applicable securities regulatory authorities and stock exchanges.

Corporate Opportunities

Our employees, contractors and directors are prohibited from taking opportunities, using Cenovus property or information or their position with Cenovus for personal gain or competing with Cenovus, based on information discovered through the use of corporate property, information or position.

Conflicts of Interest

Our employees, contractors and directors avoid situations where personal interests could conflict, or appear to conflict, with duties and responsibilities or the interests of Cenovus. A conflict of interest may occur where involvement in any activity, with or without the involvement of a related party, prevents the proper performance of employee, contractor and director duties for Cenovus, or creates, or appears to create, a situation where judgment or ability to act in the best interests of Cenovus is affected. The Conflict of Interest Practice provides further guidance and examples regarding conflict of interest situations.

When faced with an actual or potential conflict of interest, our employees follow the procedures outlined in the Conflict of Interest Practice and contractors review and follow the provisions of their written contracts. Our officers and directors follow obligations that are set out in relevant statutes and company by-laws and inform the Chair of the Board of Directors of any such conflict. Our commitment is to ensure that employees and contractors are not involved in any decision or operation related to a conflict and that officers or directors are not involved in any decision or operation related to a conflict. This is the commitment of our employees, our Executive Team and our Board of Directors.

Fraud and other Similar Irregularities

At Cenovus, we are committed to protecting the revenue, property, information and other assets of the company and our shareholders from any attempt, either by the public, contractors, agents or our own employees, to gain financial or other benefit by deceit, in the course of our business.

Our employees, contractors and directors must not, under any circumstances, misappropriate funds, property or other assets, or knowingly assist another individual to do so. Similarly, our employees, contractors and directors are not to use, borrow, loan, take, transfer or convert any assets that do not belong to them, or use them for the benefit of themselves or anyone other than the rightful owners, and are not to knowingly assist another individual to do so.

Our employees, contractors and directors will only claim those expenses that are eligible for reimbursement under Cenovus's expense guidelines and will not use the corporate credit card for personal expenses other than in accordance with Cenovus's credit card guidelines.

We have zero-tolerance for fraudulent activities and fully investigate any suspected acts of fraud, misappropriation or other similar irregularity. Cenovus will pursue every reasonable effort, including court-ordered restitution, to obtain recovery of Cenovus's losses from the offender or other appropriate sources.

Any employee or contractor who has knowledge of an occurrence of fraud, or has reason to suspect that a fraud has occurred, must immediately notify their supervisor or company contact or may report their suspicions in accordance with the Investigations Practice or to the Integrity Helpline.

Confidentiality and Disclosure

Confidential information includes all non-public information that might be of use to competitors, or harmful to Cenovus or its customers, if disclosed. Confidential or proprietary information and Cenovus's intellectual property must not be disclosed without proper safeguards, or specific authorization given, to do so or such disclosure is legally mandated. Knowledge of confidential information about another company gained in the course of work duties at Cenovus must be protected in the same manner as confidential information about Cenovus.

Our employees, contractors and directors must not violate or infringe the intellectual property rights or breach any obligations relating to the confidential information of Cenovus or of others. The Intellectual Property Practice provides further guidance regarding the use and protection of intellectual property at Cenovus.

Employees, contractors and directors must not speak on behalf of Cenovus unless authorized to do so and should refer to the Policy on Disclosure, Confidentiality and Employee Trading.

Taking advantage of, or benefiting from, information obtained at work that is not available to the public is not permitted. Friends, relatives and associates must not benefit from such information. Where insider information is known and not yet publicly disclosed, employees, contractors and directors must avoid acquiring or disposing of any business interest, including publicly traded securities, whether directly or through another person.

If an employee or contractor is not sure whether information has been publicly disclosed, they should consult with a member of Cenovus's Legal group for guidance before engaging in any transaction in any securities of Cenovus. Officers and directors should consult on such matters with the persons listed in the Restricted Trading and Insider Guidelines for guidance before engaging in any transaction in any Cenovus securities. All securities transactions are subject to the Policy on Disclosure, Confidentiality and Employee Trading and if applicable, the Restricted Trading and Insider Guidelines.

These confidentiality obligations remain in effect even beyond termination of employment, service agreements or Board of Directors appointments with Cenovus or its affiliates.

Safety

We are safety focused at Cenovus. In all our activities and operations, staff are required to:

- act in a manner consistent with our Safety Commitments
- complete health and safety training commensurate with the degree of risk associated with the activity or operation they are engaged in or as required by the company
- continuously identify and eliminate or manage health and safety risks associated with our activities and operations
- comply with all applicable health and safety related laws and regulations, and company policies and practices

Acceptable Use of Cenovus's Systems and Assets

Cenovus's corporate information, data, information system assets, office equipment, tools, vehicles, supplies, facilities and services are provided for authorized business purposes. Our employees, contractors, and directors have an obligation to use these assets in accordance with fundamental principles of reasonable and acceptable use and are not permitted to engage in unacceptable use of those assets.

Acceptable use is demonstrated when each individual:

- consistently ensures the confidentiality, integrity and availability of Cenovus's information
- takes acceptable measures to protect Cenovus's rights and property ownership of information system assets

Personal use is considered reasonable if it:

- involves appropriate content
- does not put Cenovus at risk of violating the copyrights on any materials
- is in alignment with regional laws, legislation, and Cenovus values
- occurs for short periods of time and does not interfere with day-to-day responsibilities of Cenovus staff

Unacceptable use (whether personal or business) includes when an individual acts so as to:

- defame, slander, harass, annoy or cause needless anxiety to another person or another organization
- conduct any illegal or unethical activity
- conduct any activity that could adversely affect Cenovus or Cenovus's reputation
- intentionally transmit viruses or transmit virus warnings to any recipient other than the Service Desk
- make excessive or inappropriate use of non-business-related Internet sites, chat rooms, blogs, discussion rooms, or social networking sites (e.g. Facebook, MySpace, Twitter) for personal reasons
- replace personal assets (e.g. home telephone land line or personal PC)

- exchange any of the following types of content:
    - personal commercial, advertising or political material
    - pictures, jokes or content that conflict with this Code of Business Conduct & Ethics
    - chain letters
    - obscene or sexually explicit messages, pictures, cartoons or jokes
    - ethnic, religious, gender-related, disability-related or racial slurs
    - confidential, sensitive or proprietary information to unauthorized recipients
    - material that could damage Cenovus's image or reputation

Cenovus's information system assets and other assets must not be used for personal commercial ventures.

Cenovus staff should also consult the Records and Information Management Policy and the Information Security Practice website for further guidance related to Acceptable Use.

Inducements and Gifts

At Cenovus, we do not accept or give gifts, favours, personal advantages, services payments, loans, or benefits of any kind, other than those of nominal value that can be made as a generally accepted business practice. The Acceptance of Gifts Guideline provides further guidance regarding gift-giving and receiving and should be referred to and or written approval from Cenovus leaders should be requested. Gift-giving practices may vary among different cultures, and therefore local gift practices and guidelines will be considered when addressing these issues.

We do not tolerate soliciting, accepting, or paying bribes or other illicit payments for any purpose. Situations must be avoided where judgment might be influenced by, or appears to be influenced by such unlawful or unethical behavior. Payment or acceptance of any "kickbacks" from a contractor or other external party is strictly prohibited.

Illicit or improper payments to foreign officials are strictly prohibited. Cenovus is subject to and abides by the Corruption of Foreign Public Officials Act (Canada), the Foreign Corrupt Practices Act (U.S.A.), the U.K. Bribery Act and equivalent legislation in other countries. Non-compliance could have serious ramifications for Cenovus and for staff.

Political Activities

Cenovus does not participate in improper intervention in political processes and does not make financial contributions or contributions in kind (e.g. properties, materials or services) to political parties, committees or their representatives, unless permitted by law, and approved in advance by Cenovus's Vice-President, Government & Community Affairs, as delegated by the President & Chief Executive Officer and Executive Vice-President, Environment & Corporate Affairs. All contributions will be reported annually to the Board of Directors. In such situations, we fully comply with legal requirements for public disclosure.

At Cenovus, our employees, contractors and directors may choose to become involved in political activities as long as they undertake these activities on their own behalf and may, on a personal level, give to any political party or candidate. Reimbursement by the company is prohibited.

Lobbying Activities

We comply with all applicable lobbying legislation including the Lobbying Act (Canada), the Lobbyists Act (Alberta) and the Lobbyists Registration Act (British Columbia) which impose reporting requirements on lobbying communications with certain officers and employees of the Government of Canada, the Government of Alberta and the Government of British Columbia (known in Canada as "Public Office Holders" or "POHs"). Employees must not have communications with a POH unless they have been registered by Cenovus, except where otherwise permitted by the applicable legislation.

Fair Dealing

Our employees, contractors and directors endeavour to deal fairly with Cenovus's customers, contractors, industry partners, employees and any other stakeholders, and to not take unfair advantage of anyone through manipulation, concealment, abuse of privileged information, misrepresentation of material facts, or any other unfair-dealing practice.

Acquisition and Supply of Goods & Services

It is the responsibility of all Cenovus employees and contractors involved in the acquisition of goods and services to act in a financially responsible and ethical manner.

Employees are required to:

- acquire goods and services through company defined practices and guidelines
- ensure the necessary parties are involved in the process, and that required approvals are obtained for agreements, contracts and purchasing activities
- support the principle of company-wide buying power to achieve security of supply, reduction in total cost of ownership, and the best supply arrangements to meet the needs of Cenovus
- engage with the supplier community in a manner that is fair and aligned with the Cenovus Values and Work Principles (e.g., safety focused, local and aboriginal, environmentally focused, and innovation focused suppliers)
- ensure that engagement of suppliers and contractors is conducted in a manner that avoids conflicts of interest or perceived conflicts of interest (as described earlier in the Code)

All employees are required to ensure suppliers and contractors are managed in accordance with the above, as well as all associated Practices. The associated practices once approved will provide further guidance regarding the acquisition and supply of goods and services at Cenovus.

Company Records

Records must be kept and maintained to fulfill relevant legal requirements. Recording and reporting information, including information related to operations, environment, health, safety, training, human resources and financial matters, must be done honestly, accurately and with care.

Accuracy of Books and Records

At Cenovus we understand that the books and records of Cenovus must reflect in reasonable detail its transactions in a timely, fair and accurate manner to, among other things, permit the preparation of accurate financial statements in accordance with generally accepted accounting principles and maintain recorded accountability for assets and liabilities. The accuracy of asset and liability records must be maintained by comparing the records to the existing assets and liabilities at reasonable intervals, and taking appropriate action with respect to any differences.

All business transactions that employees, contractors and directors have participated in must be properly authorized, properly recorded and supported by accurate documentation in reasonable detail.

Accounting, Auditing or Disclosure Concerns

Cenovus is required to provide full, fair, accurate, timely and understandable disclosure in reports and documents that are filed with, or submitted to, the U.S. Securities and Exchange Commission, the Alberta Securities Commission and other Canadian securities regulatory authorities, the Toronto Stock Exchange and the New York Stock Exchange, as well as in other public communications made by Cenovus. All employees and contractors responsible for the preparation of Cenovus's public disclosures, or who provide information as part of the process, ensure that disclosures are prepared and information is provided honestly, accurately and in compliance with the various Cenovus disclosure controls and procedures.

All employees, contractors and directors have a duty to submit any good faith questions and concerns regarding questionable accounting, auditing or disclosure matters or controls. Submissions about these or similar matters should be reported in accordance with the Investigations Practice.

To the extent that potential violations involve Cenovus's accounting, internal accounting controls or auditing matters (including questionable accounting or auditing matters), investigations under this Code will be overseen by, and be the ultimate responsibility of, the Audit Committee of the Board of Directors.

No information may be concealed from Cenovus's external auditors, internal auditors, the Board of Directors, or the Audit Committee of the Board of Directors. It is illegal to fraudulently influence, coerce, manipulate or mislead an external auditor who is auditing Cenovus's financial statements.

Human Rights and Harassment

We do not tolerate unlawful workplace conduct, including discrimination, intimidation or harassment. We are committed to maintaining a positive workplace where all staff adheres to relevant human rights legislation and acts ethically, honestly and treats all others we come in contact with during our work with dignity, fairness and respect. Any form of unlawful harassment or discrimination based on age, gender, race, color, religion, creed, national or ethnic origin, citizenship, linguistic or cultural background, marital or family status, sexual orientation or physical or mental disability will not be tolerated.

Observance of the Code of Business Conduct & Ethics

All employees and directors are personally accountable for learning, endorsing and promoting this Code and applying it to their own conduct and field of work. All employees and directors are asked to review this Code, to confirm on a regular basis, through written or electronic declaration, that they understand their individual responsibilities and to acknowledge they conform to the requirements of the Code.

Contractors are expected to develop and enforce with their staff, policies and/or practices that are consistent with this Code and its associated requirements and to acknowledge their compliance in writing.

Employees or contractors with questions about this Code or specific situations are encouraged to refer the matter to their supervisor or leader or the persons listed in any referenced policy or practice, as applicable. Applicable resource groups such as internal legal counsel or Human Resources may also be contacted. Officers and directors with questions about this Code or specific situations are encouraged to refer the matter to the Chief Executive Officer or the Chair of the Board of Directors or the persons listed in any referenced policy or practice, as applicable.

Reporting Violations of the Code of Business Conduct & Ethics

Actions that violate or appear to violate this Code will be reported in accordance with Cenovus's Investigations Practice. The Investigations Practice outlines how a report will be treated once it is made, protection for complainants and the consequences of violating this Code. Violations may be reported to Cenovus staff, the Investigations Committee, or through the Integrity Helpline.

Violation of this Code and its associated guidelines may result in disciplinary action up to and including termination of employment or contract for services.

Whistleblower Protection

Retaliation against individuals (whether employees, contractors or other third parties) who report violations of this Code will not be tolerated. Every supervisor has the responsibility to create an environment in which staff can raise business conduct concerns or violations under this Code without fear of retaliation.

No adverse action will be taken against individuals making a good faith report of a business conduct concern or violation under this Code, whether or not the report ultimately proves to be well founded. Good faith does not mean that the individual reporting the concern or violation has to be right; but it does mean that the individual believes he/she is providing truthful and accurate information.

On the other hand, we will not tolerate reports that are not made in good faith, such as reports intentionally providing false information or made maliciously to harm the company or another employee or contractor. Disciplinary action, up to and including termination of employment or services, may be taken against an employee or contractor knowingly making false reports.

Individuals are strongly encouraged to report business conduct concerns or violations of this Code to their supervisor or Human Resources advisor (if an employee or contractor), or to a member of the Investigations Committee or to the Integrity Helpline. Any individual who believes retaliation has occurred should contact the Integrity Helpline immediately.

Waivers and Amendments

Waivers of this Code for employees or contractors may be granted only by a Vice-President in limited, exceptional circumstances. Any waiver of this Code for officers or directors may only be made by the Board of Directors and will be promptly disclosed to shareholders to the extent required by law, rule, regulation or stock exchange requirement.

Amendments to this Code will be publicly disclosed to the extent required by law, rule, regulation or stock exchange requirement.