Annual Information Form

For the year ended December 31, 2013

February 12, 2014

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FORWARD-LOOKING INFORMATION

This Annual Information Form ("AIF") contains 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. This forward-looking information is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, forecasted commodity prices, future use and development of technology and projected increasing shareholder value. 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 Energy Inc. 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 our current guidance, available at cenovus.com; our 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; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; 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.

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 and the success of our hedging strategies; 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 earnings before interest, taxes, depreciation and amortization as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship 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 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 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 this AIF. Readers should also refer to "Risk Management" in our current Management's Discussion and Analysis and to the risk factors described in other documents we file from time to time with securities regulatory authorities, available at www.sedar.com, www.sec.gov and on our 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, we amalgamated with our wholly owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Alberta Court of Queen's Bench.

Unless otherwise specified or the context otherwise requires, references to "we", "us", "our", "its", "Company" or "Cenovus" mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries.

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

Intercorporate Relationships

The following table summarizes our principal subsidiaries and partnerships at December 31, 2013:

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

Notes:
(1) Includes direct and indirect ownership.
(2) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL.
(3) Cenovus interest held directly through Cenovus US Holdings Inc.

The above table includes our subsidiaries and partnerships which have total assets that exceed 10 percent of our total consolidated assets, or revenues which exceed 10 percent of our total consolidated revenues. The assets and revenues of our unidentified subsidiaries and partnerships did not exceed 20 percent of our total consolidated assets or total consolidated revenues at and for the year ended December 31, 2013.

GENERAL DEVELOPMENT OF OUR BUSINESS

Cenovus is a Canadian integrated oil company headquartered in Calgary, Alberta. We are in the business of developing, producing and marketing crude oil, NGLs and natural gas in Canada with refining operations in two refineries in the United States ("U.S.") in Illinois and Texas.

We began independent operations on December 1, 2009 following the split of Encana into two independent publicly traded energy companies, Cenovus and Encana.

Our Business

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 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 focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points 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, research costs and financing activities. 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 operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation.

Three Year History

The following describes the significant events of the last three fiscal years in respect of our business:

2013

- In the first quarter, we 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 bbls/d from each phase.
- In the first quarter, we achieved first production from the second pilot well pair at Grand Rapids. We operated the pilot project at Grand Rapids throughout the year. The purpose of the pilot is to test reservoir performance.
- In the second quarter, we updated our 10 year strategic plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023.
- In the third quarter, we sold our Lower Shaunavon asset to an unrelated third party for proceeds of approximately $240 million plus closing adjustments.

- In the third quarter, phase E of Christina Lake achieved first production, with expected gross production capacity of 40,000 bbls/d.
- In the third quarter, we 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 our US$800 million senior unsecured notes due September 2014.
- 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 bbls/d.
- In the third quarter, we 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 bbls/d of gross production capacity to the Christina Lake facility.
- In the fourth quarter, the Telephone Lake dewatering pilot was successfully completed. We effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water.
- In the fourth quarter, we increased our rail shipping capacity to 10,000 bbls/d.
- In the fourth quarter, we received US$1.4 billion from ConocoPhillips, our partner in FCCL, representing the remaining principal and interest due under the Partnership Contribution Receivable through our interest in FCCL, net to Cenovus.
- Timing of optimization work for Foster Creek phases F, G and H has been 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 bbls/d. Once these phases are complete, optimization work to lower steam to oil ratios, increase production and improve plant efficiency is expected to commence. Total gross production capacity from these three phases, including optimization, remains unchanged at 125,000 bbls/d.

2012

- In the second quarter, the expected gross production capacity for Christina Lake phase H was increased from 40,000 bbls/d to 50,000 bbls/d due to the addition of a fifth steam generator that will incorporate blowdown boiler technology. This is expected to increase steam capacity and enhance efficiency by increasing the water recycle rate, leading to fuel savings and a reduction in water use. We commercialized blowdown boiler technology in 2011 after testing it at Foster Creek.
- In the second quarter, we received regulatory approval for the Narrows Lake project, which includes the use of both traditional steam-assisted gravity drainage ("SAGD") and SAGD with the Solvent Aided Process ("SAP") enhancement. In the fourth quarter, phase A, which has planned gross production capacity of 45,000 bbls/d, received partner approval. The Narrows Lake project is currently expected to have gross production capacity of 130,000 bbls/d in three phases.
- In the second quarter, ConocoPhillips, our partner in FCCL and WRB, proceeded with the spin-off of its downstream business from its exploration and production business, which was announced in the third quarter of 2011. The exploration and production entity retained the ConocoPhillips name and continues to be our partner in FCCL. The downstream entity was named Phillips 66 and is our partner in WRB.
- 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 bbls/d in 2012.
- In the third quarter, steam injection commenced on the second well pair at Grand Rapids, with first production achieved in the first quarter of 2013 from this pilot well.
- In the third quarter, we 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.

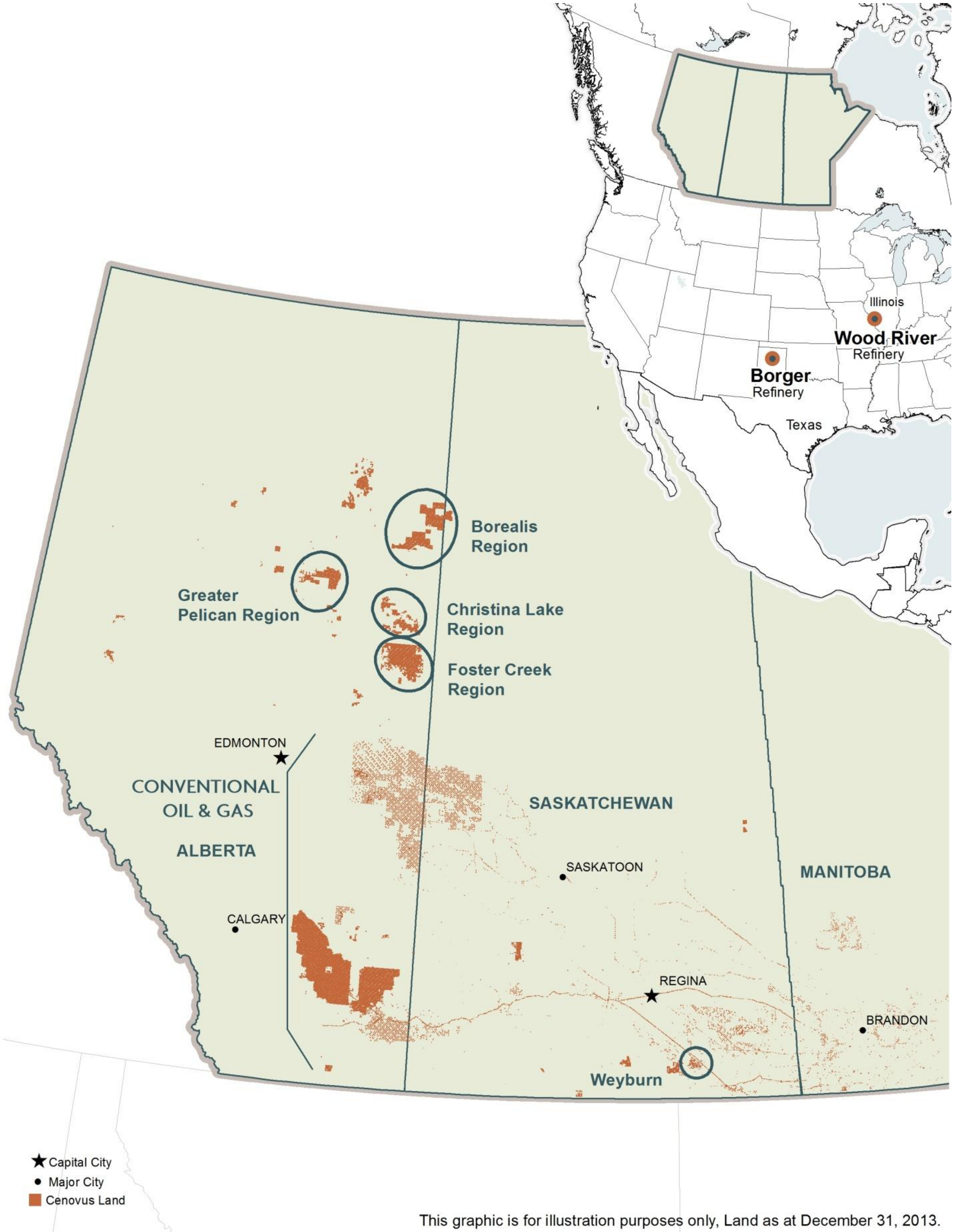
- In the fourth quarter, with the drilling and facility construction completed, operation of the Telephone Lake dewatering pilot commenced.
- In the fourth quarter, we received regulatory approval to add cogeneration facilities at Christina Lake and increase expected total gross production capacity by 10,000 bbls/d at each of phase F and G.
- In the fourth quarter, we acquired assets located adjacent to our proposed Telephone Lake oil sands project in northern Alberta for cash of $10 million and the assumption of related decommissioning obligations.

2011

- In the second quarter, we updated our 10 year strategic plan, identifying oil sands bitumen production of more than 400,000 bbls/d net and total oil production of approximately 500,000 bbls/d net, by the end of 2021.
- In the second quarter, we received regulatory approval for Christina Lake phases E, F and G. Planned gross production capacity for each expansion phase is 40,000 bbls/d for a total of 120,000 bbls/d of bitumen. Also in the second quarter, partner approval was received for phase E.
- In the second quarter, we received approval from the Alberta Department of Energy ("ADOE") to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation.
- In the second quarter, we announced plans to increase gross production capacity at each of Foster Creek phases F, G and H from 30,000 to 35,000 bbls/d and received partner approval for each phase. Planned gross production capacity for each expansion phase was further increased to 40,000 bbls/d for phases G and H and to 45,000 bbls/d for phase F, due to the success of our Wedge Well™ technology and plant optimization. Total gross production capacity for these three phases at completion is expected to be 125,000 bbls/d of bitumen.
- In the third quarter, phase C of Christina Lake achieved first production ahead of schedule and with capital expenditures below budget for the entire phase. Net production at Christina Lake during 2011 averaged 11,665 bbls/d and ended 2011 at approximately 23,000 bbls/d.
- In the fourth quarter, we completed coker construction and start-up activities of the Coker and Refinery Expansion ("CORE") project, at the Wood River Refinery. CORE project capital expenditures were within 10 percent of its original budget. The CORE project has been successful and has resulted in the capability to increase clean product yield by up to five percent. The Wood River Refinery's total processing capability of heavy crude oil has also increased to up to 220,000 bbls/d.
- In the fourth quarter, Cenovus filed a joint application and EIA for a commercial SAGD operation at Grand Rapids with an expected gross production capacity of 180,000 bbls/d.
- In the fourth quarter, progressing the Telephone Lake project, we filed a revised joint regulatory application and EIA. This application updates the expected gross production capacity to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007.
- In the fourth quarter, we applied for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 bbls/d at each of phase F and phase G.

NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our upstream and refining assets as at December 31, 2013:



Overview

All of our reserves and production are located in Canada, primarily within the provinces of Alberta and Saskatchewan. At December 31, 2013, we had a land base of approximately 7.0 million net acres. The estimated proved reserves life index based on working interest production at December 31, 2013 was approximately 24 years.

The following table summarizes our Company Interest Before Royalties proved and probable reserves at December 31, 2013:

Company Interest Before Royalties (1)		
	Proved	**Probable**
Bitumen (MMbbls)	1,846	683
Heavy Oil (MMbbls)	179	140
Light & Medium Oil and NGLs (MMbbls)	115	50
Natural Gas & CBM (Bcf)	865	300

Note:
(1) Does not include Royalty Interest Reserves. Please refer to the "Reserves Data and Other Oil and Gas Information" section for additional information.

The following narrative describes our operations in greater detail.

Oil Sands

Oil Sands includes our bitumen assets at Foster Creek, Christina Lake and Narrows Lake, as well as new resource play assets including Grand Rapids and Telephone Lake, plus our Athabasca natural gas assets. Foster Creek, Christina Lake and Narrows Lake are jointly owned through FCCL with ConocoPhillips, an unrelated U.S. public company.

Cenovus FCCL Ltd., our 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.

In 2013, our Oil Sands capital investment was $1,883 million, and was primarily related to the expansion of the production capacity of FCCL's assets. FCCL plans to increase gross production capacity to approximately 285,000 bbls/d of bitumen with the addition of Christina Lake phase E in the third quarter of 2013 and first production from Foster Creek phase F expected in the third quarter of 2014. Overall progress of Foster Creek expansion phases F, G and H is approximately 63 percent complete, while the phase F plant facility is approximately 90 percent complete. We also continued to assess the potential of our new resource play assets during 2013 with our stratigraphic test well program.

Plans for 2014 include the continued development of expansion phases at both Foster Creek and Christina Lake and engineering, procurement, and construction of the phase A plant at Narrows Lake. Overall Narrows Lake phase A is approximately 16 percent complete, while the central plant is approximately 21 percent complete. Plans for 2014 also include the continuation of an active stratigraphic test well drilling program with 291 gross wells planned. The dewatering pilot at Telephone Lake was completed in the fourth quarter of 2013 and we have effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water in the pilot area. Steam injection commenced in the third quarter of 2012 on our second well pair at the Grand Rapids pilot and first production was achieved in February 2013.

At December 31, 2013, we held bitumen rights of approximately 1.4 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 our behalf and/or our assignee's behalf on the Cold Lake Air Weapons Range.

The following table summarizes our landholdings at December 31, 2013:

Landholdings – Oil Sands	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Foster Creek	15	8	125	62	140	70	50%
Christina Lake	8	4	50	25	58	29	50%
Narrows Lake	-	-	26	13	26	13	50%
Grand Rapids	-	-	73	73	73	73	100%
Telephone Lake	16	16	142	142	158	158	100%
Athabasca	417	345	454	380	871	725	83%
Other	27	9	1,018	737	1,045	746	71%
Total	483	382	1,888	1,432	2,371	1,814	77%

The following table summarizes our share of daily average production for the periods indicated:

Production – Oil Sands	**Crude Oil and NGLs (bbls/d)**		**Natural Gas (MMcf/d)**		**Total Production (BOE/d)**	
(annual average)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Foster Creek	53,190	57,833	-	-	53,190	57,833
Christina Lake	49,310	31,903	-	-	49,310	31,903
Athabasca (1)	-	-	21	30	3,500	5,000
Total	102,500	89,736	21	30	106,000	94,736

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

The following table summarizes our interests in producing wells at December 31, 2013. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2013:

Producing Wells – Oil Sands	**Producing Oil Wells**		**Producing Gas Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Foster Creek	236	118	-	-	236	118
Christina Lake	98	49	-	-	98	49
Grand Rapids	2	2	-	-	2	2
Athabasca	-	-	299	299	299	299
Other	2	2	-	-	2	2
Total	338	171	299	299	637	470

Foster Creek

We have a 50 percent working interest in Foster Creek, an oil sands property situated on the Cold Lake Air Weapons Range in northeastern Alberta that uses SAGD technology and produces from the McMurray formation. We hold 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, we hold exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on our behalf and/or our assignee’s behalf.

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. Each phase is expected to ramp-up to its initial design capacity of 30,000 bbls/d. Once these phases are complete, optimization work will commence to reduce steam to oil ratio, increase production and improve plant efficiency. Total gross production capacity for these phases, including optimization work, is expected to reach 125,000 bbls/d. Production from phase F is expected to start in the third quarter of 2014 with production ramp-up to design capacity expected to take twelve to eighteen months. Production from phases G and H is expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. With the addition of these four phases, Cenovus expects Foster Creek will have the capacity to produce 295,000 bbls/d gross and potentially as much as 310,000 bbls/d gross with optimization.

We have successfully piloted and implemented our 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 2013, 30 wells using our Wedge Well™ technology were drilled (2012 – no wells) at Foster Creek. At December 31, 2013 there were 65 gross producing wells of this type.

We operate 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

We have a 50 percent working interest in Christina Lake, an oil sands property in northeastern Alberta that uses SAGD technology and produces from the McMurray formation. Full capacity was reached at phase D in the first quarter of 2013 and phase E had first oil production in the third quarter of 2013. With the addition of phase E, gross production capacity at Christina Lake of 138,000 bbls/d is expected to be achieved in the first quarter of 2014. Phases F, including cogeneration, and G are expected to add approximately 50,000 bbls/d of gross production capacity from each phase. Expansion work is continuing as planned and we expect production from phases F and G in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program at phases C, D and E, which is expected to add up to 22,000 bbls/d of gross capacity in 2015. We submitted a joint application and EIA to regulators in the first quarter of 2013 for the phase H expansion, a 50,000 bbls/d phase for which we expect regulatory approval in the fourth quarter of 2014. With the addition of phases F, G and H, we believe Christina Lake has potential gross production capacity of 288,000 bbls/d, increasing to as much as 310,000 bbls/d with optimization. In 2013, we drilled 11 wells (2012 – three wells) at Christina Lake using our Wedge Well™ technology and at December 31, 2013 there were 10 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. This SAP pilot utilizes a mixture of steam and solvent to enhance recovery of the bitumen by increasing production rates and overall oil recovery, as well as reducing the steam to oil ratio. Results from the pilot were as expected, and we plan to commercialize the SAP technology with phase A of our Narrows Lake project.

We have applied steam dilation technology as part of the Christina Lake phase C start-up and select wells on phases D and E. As steam is injected into the injector and producer wells, the force of the steam rearranges the sand grains and creates gaps, which are filled with water. This increases both porosity and water mobility, allowing fluid flow between the wells. Steam dilation requires minimal additional costs or surface facility modifications, takes less than one month and results in more uniform start-up along the full length of the well pairs. This allows the well to reach peak production rates more quickly. Steam dilation benefits include a faster start-up time, a reduction in steam circulation time and a decrease in cumulative steam to oil ratio.

Narrows Lake

We hold a 50 percent working interest in Narrows Lake, an oil sands property within the Christina Lake Region in northeastern Alberta. The project includes planned gross production capacity of 130,000 bbls/d of bitumen. In the second quarter of 2012, we 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 of 2012, phase A, which has planned gross production capacity of 45,000 bbls/d, received partner approval. During 2013, site preparation for the phase A plant at Narrows Lake was completed and construction of the plant commenced. Site construction, engineering and procurement, and construction of the phase A plant are progressing as planned. The project is expected to begin producing in 2017.

New Resource Play Assets

Our new resource play assets include our emerging oil sands properties as described below.

Grand Rapids

Our 100 percent owned Grand Rapids property is located in the Greater Pelican Region in northeastern Alberta, where large deposits of bitumen have been identified in the Cretaceous Grand Rapids formation. In the fourth quarter of 2011, we filed a joint application and EIA for a commercial operation with production capacity of 180,000 bbls/d and we anticipate regulatory approval in the first quarter of 2014. During 2013, we continued to operate the pilot project at Grand Rapids and achieved first production from the second well pair in the first quarter of 2013. The purpose of the pilot is to test reservoir performance.

Telephone Lake

Our 100 percent owned Telephone Lake property is located in the Borealis Region in northeastern Alberta. A revised joint application and EIA was submitted in the fourth quarter of 2011 to the Alberta Energy Regulator ("AER"), formerly the Alberta Energy Resources Conservation Board, and Alberta Environment and Sustainable Resource Development for the development of the property, including the construction of a facility with planned bitumen production capacity of 90,000 bbls/d. We anticipate receiving regulatory approval in the second quarter of 2014. In 2013, we effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water. The water displaced was not potable and therefore not suitable to be used for human or other consumption. Capital investment decreased in 2013 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012.

Other Assets

The Steepbank and East McMurray properties are also located in the Borealis Region, southwest of Telephone Lake. An active stratigraphic drilling program is being carried out at these properties. In 2013, 50 gross stratigraphic wells were drilled.

We have completed a pilot program which uses a helicopter and an experimental lightweight drilling rig to drill stratigraphic test wells. The SkyStrat™ drilling rig is a new rig we developed to improve stratigraphic drilling programs in the oil sands, as the rig is transported by helicopter which allows us to access remote exploratory drilling locations year-round. Transporting by helicopter eliminates the need for temporary roads, which significantly reduces the surface footprint and has the potential to reduce water use for the drilling operations by over 50 percent. In the second and third quarters of 2013, this rig was used to drill 24 stratigraphic wells. We expect to complete construction and testing of a second SkyStrat™ drilling rig by the end of the second quarter of 2014.

Athabasca Gas

We produce natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeastern Alberta and hold 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 our natural gas production in the area is processed through wholly-owned and operated compression facilities.

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 at risk the recovery of bitumen resources in the area. The decisions resulted in a decrease in our annualized natural gas production of approximately 16 million cubic feet per day in 2013 (2012 – 19 million cubic feet per day). The ADOE provides financial assistance in the form of a royalty credit, which can equal up to approximately 50 percent of the cash flow lost as a result of the shut-in wells over a ten year period. This royalty credit is also dependent on natural gas prices. The royalty credit for some of these wells reached the end of the ten year period in the third quarter of 2013.

Conventional

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

At December 31, 2013, we had an established land position of approximately 5.4 million gross acres (5.2 million net acres), of which approximately 3.3 million gross acres (3.2 million net acres) are developed. The mineral rights on approximately 61 percent of our net landholdings are owned in fee title by Cenovus, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights. We may lease out a portion of our fee lands in areas where the land is not consistent with our long range business plan. We lease Crown lands in some areas in Alberta, mainly in the Early Cretaceous geological formations, primarily in the Suffield and Wainwright areas. In Saskatchewan, the majority of our current production comes from crown lands leased from the Province of Saskatchewan.

In 2013, our Conventional capital investment was $1,191 million and primarily focused on crude oil properties. This investment included drilling and facilities work in Weyburn, spending at Pelican Lake on the expansion of the polymer flood as well as drilling, completion and facilities work in our tight oil opportunities in Alberta.

Plans for 2014 include oil-focused capital investment to further develop our existing assets in Alberta and Saskatchewan. The spending will include additional drilling, including infill drilling at Pelican Lake, well optimizations, well recompletions and investment in our existing facility infrastructure.

The following table summarizes our landholdings at December 31, 2013:

Landholdings – Conventional	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Alberta							
Brooks North	571	569	8	8	579	577	100%
Suffield	917	906	142	141	1,059	1,047	99%
Langevin	737	697	245	228	982	925	94%
Pelican Lake	112	112	360	354	472	466	99%
Drumheller	406	392	76	74	482	466	97%
Wainwright	356	334	204	199	560	533	95%
Other	55	29	167	133	222	162	73%
Saskatchewan							
Weyburn	116	101	341	320	457	421	92%
Bakken	17	16	253	251	270	267	99%
Other	9	6	19	20	28	26	93%
Manitoba	4	4	263	263	267	267	100%
Total	3,300	3,166	2,078	1,991	5,378	5,157	96%

The following table summarizes our share of daily average production for the periods indicated:

Production – Conventional	Crude Oil and NGLs (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
(annual average)	2013	2012	2013	2012	2013	2012
Alberta						
Brooks North	3,183	2,866	205	225	37,350	40,366
Suffield	11,391	11,691	149	167	36,224	39,524
Langevin	8,754	7,719	101	109	25,587	25,886
Pelican Lake	24,254	22,552	-	-	24,254	22,552
Drumheller	4,537	3,653	47	54	12,370	12,653
Wainwright	4,668	4,417	3	3	5,168	4,917
Other	9	11	2	5	342	844
Saskatchewan						
Weyburn	16,361	16,278	-	-	16,361	16,278
Shaunavon (1)	2,095	4,411	-	-	2,095	4,411
Bakken	1,508	2,065	1	1	1,676	2,232
Other	15	4	-	-	15	4
Total	76,775	75,667	508	564	161,442	169,667

Note:
(1) In the third quarter of 2013, our Lower Shaunavon tight oil asset in southern Saskatchewan was sold.

The following table summarizes our interests in producing wells at December 31, 2013. These figures exclude wells which were capable of producing, but that were not producing, at December 31, 2013:

Producing Wells – Conventional	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Alberta						
Brooks North	168	167	7,499	7,400	7,667	7,567
Suffield	795	795	10,645	10,627	11,440	11,422
Langevin	271	268	4,803	4,790	5,074	5,058
Pelican Lake	567	567	5	5	572	572
Drumheller	237	231	1,584	1,527	1,821	1,758
Wainwright	463	432	12	3	475	435
Other	7	1	20	19	27	20
Saskatchewan						
Weyburn	670	423	-	-	670	423
Bakken	34	23	-	-	34	23
Other	5	5	-	-	5	5
Total	3,217	2,912	24,568	24,371	27,785	27,283

Crude Oil Properties

We hold interests in multiple zones in the Suffield, Brooks North, Langevin, Drumheller, and Wainwright areas in Alberta with a mix of medium and heavy crude oil production. Development in these areas focuses on horizontal drilling targeting tight oil formations, infill drilling to enhance recovery in producing areas, optimization of existing wells to maximize production and other specialized oil recovery methods that increase our overall recovery factors in each field.

In the unitized portion of the Weyburn field in southeastern Saskatchewan, we have a 62 percent working interest. However, after taking into consideration a net royalty interest obligation to a third party, our economic interest is 50 percent. The Weyburn unit produces light to medium sour crude oil from the Mississippian Midale formation and covers 78 sections of land. Cenovus is the operator and we are increasing ultimate recovery of crude oil with a CO_2 miscible flood project. At December 31, 2013, approximately 92 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 22 million tonnes of CO_2 have been injected as part of the program. The CO_2 is delivered by pipeline directly to the Weyburn facility from a coal gasification project in North Dakota, U.S. A new contract was executed in 2012 for the purchase of CO_2 from Saskatchewan Power Corporation providing an additional source of CO_2 beginning in 2014.

Using a patterned, horizontal well polymer flood, we produce heavy crude oil from the Cretaceous Wabiskaw formation at our Pelican Lake property, which is located within the Greater Pelican Region in northeastern Alberta. We hold 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.

In 2013, our capital was invested primarily in drilling and facilities work at Weyburn, infill drilling to progress the polymer flood at Pelican Lake, and drilling, completion and facilities work in our tight oil opportunities in Alberta.

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

	Net Wells Drilled		Average Production (bbls/d)			
			Light/Medium		Heavy	
Net Wells Drilled and Production	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Alberta						
Brooks North	21	52	3,034	2,707	-	-
Suffield	24	38	-	-	11,375	11,667
Langevin	36	44	8,625	7,551	-	-
Drumheller	23	33	3,970	3,051	-	-
Wainwright	39	57	40	58	4,616	4,348
Pelican Lake	49	76	-	-	24,254	22,552
Other	6	2	8	11	-	-
Saskatchewan						
Weyburn	14	6	16,229	16,277	-	-
Shaunavon [(1)]	-	36	2,095	4,411	-	-
Bakken	-	4	1,451	2,001	-	-
Other	-	4	15	4	-	-
Total	212	352	35,467	36,071	40,245	38,567

Note:
(1) In the third quarter of 2013, our Lower Shaunavon tight oil asset in southern Saskatchewan was sold.

Natural Gas Properties

We hold natural gas interests in multiple zones in the Suffield, Brooks North, Langevin and Drumheller areas in Alberta. Development in these areas focuses on recompletions and optimization of existing wells.

The following table summarizes net gas wells drilled and daily average gas production for the periods indicated:

	Net Wells Drilled		Average Production (MMcf/d)	
Net Wells Drilled and Production	**2013**	**2012**	**2013**	**2012**
Brooks North	-	-	205	225
Suffield	-	-	149	167
Langevin	-	-	101	109
Drumheller	-	-	47	54
Wainwright	-	-	3	3
Other	-	-	3	6
Total	-	-	508	564

Suffield is one of the core areas of our 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. Our predecessor companies, Alberta Energy Company Ltd. and Encana, have operated at CFB Suffield for over 30 years.

Natural gas assets are an important component of our financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations because natural gas partially fuels the Company's oil sands and refining operations.

We plan to prudently manage declines in natural gas volumes, targeting a long-term production level that will match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining and Marketing

Refining

Through WRB we have 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 2014, on a 100 percent basis, our refineries have a combined stated processing capacity of approximately 460,000 bbls/d of crude oil (2013 – 457,000 bbls/d), including heavy crude oil processing capability of up to 255,000 bbls/d.

Wood River Refinery

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 feedstocks 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. Throughout 2013, the Wood River Refinery had stated processing capacity of 311,000 bbls/d. Since the start-up of the CORE project that was substantially completed in 2011, the Wood River Refinery has demonstrated the benefits of this project, including Canadian heavy crude oil processing capability of up to 220,000 bbls/d. In 2013, 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.

For 2014, the Wood River Refinery's stated processing capacity is 314,000 bbls/d of crude oil. This figure is determined based on the guidelines for calculating maximum demonstrated rate, which is 95 percent of the highest average rate achieved over a continuous 30 day period.

Borger Refinery

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.

Throughout 2013 and for 2014, the Borger Refinery's stated processing capacity is approximately 146,000 bbls/d of crude oil, including approximately 35,000 bbls/d of heavy crude oil, and approximately 45,000 bbls/d of NGLs.

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

Refinery Operations [1]	**2013**	**2012**
Crude Oil Capacity (Mbbls/d)	457	452
Crude Oil Runs (Mbbls/d)	442	412
Heavy Oil	222	198
Light/Medium	220	214
Crude Utilization (%)	97	91
Refined Products (Mbbls/d)		
Gasoline	232	216
Distillates	144	138
Other	87	79
Total	463	433

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

Marketing

Our Marketing group is focused on enhancing the netback price of our production. As part of these activities, the group also carries out third-party purchases and sales of product to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

We also seek to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced products. Details of transactions related to our various risk management positions for crude oil, natural gas and power are found in the notes to our audited Consolidated Financial Statements for the year ended December 31, 2013.

Crude Oil Marketing

This group manages the transportation and marketing of crude oil for our upstream operations. Cenovus's 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. Our portfolio of transportation commitments includes feeder pipelines from our 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 2013, in conjunction with the Company's priority to ensure future market access, we entered into various firm transportation commitments totaling over $11 billion, most of which are subject to regulatory approval. The Company's longer term target is to commit to transportation solutions for up to 50 percent of marketable production, including growing rail capacity by up to 10 percent of marketable production.

Natural Gas Marketing

We also manage the marketing of our natural gas, which is primarily sold to industrials, other producers and energy marketing companies. Prices received by us are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels and by North American regional supply and demand for natural gas.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Our reserves are primarily located in Alberta and Saskatchewan, Canada. We 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 our bitumen, heavy oil, light and medium oil, NGLs, natural gas, and CBM reserves. McDaniel evaluated approximately 96 percent of our total proved reserves, located throughout Alberta and Saskatchewan, and GLJ evaluated approximately four percent of our total proved reserves, located at Weyburn. We also engaged McDaniel to evaluate 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of our 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 IQRE to report on the reserves data without reservation. In addition, the Reserves Committee reviews the reserves and resources data and the report of the IQRE and provides a recommendation regarding approval of the reserves and resources disclosure to the Board.

The majority of our 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. We have 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, 2014, with an effective date of December 31, 2013. McDaniel's preparation date of the information is January 13, 2014, and GLJ's preparation date is January 10, 2014.

Disclosure of Reserves Data

The reserves data presented summarizes our 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.

We hold significant fee title rights which generate production for our account from third parties leasing those lands ("Royalty Interest Production"). At December 31, 2013, 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 at December 31, 2013
(Forecast Prices and Costs)

Before Royalties [1]				
Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	192	129	89	834
Developed Non-Producing	25	3	11	27
Undeveloped	1,629	47	15	4
Total Proved Reserves	1,846	179	115	865
Probable Reserves	683	140	50	300
Total Proved plus Probable Reserves	2,529	319	165	1,165

After Royalties [2]				
Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	149	108	78	846
Developed Non-Producing	18	3	8	27
Undeveloped	1,241	40	12	4
Total Proved Reserves	1,408	151	98	877
Probable Reserves	522	107	42	283
Total Proved plus Probable Reserves	1,930	258	140	1,160

Royalty Interest				
Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	-	1	6	42
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved Reserves	-	1	6	42
Probable Reserves	-	-	2	11
Total Proved plus Probable Reserves	-	1	8	53

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

Summary of Net Present Value of Future Net Revenue at December 31, 2013
(Forecast Prices and Costs)

Before Income Taxes						
	Discounted at %/year ($ millions)					Unit Value Discounted at 10% [1]
Reserves Category	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	15,530	12,761	10,868	9,514	8,498	22.81
Developed Non-Producing	1,467	1,042	802	644	536	23.84
Undeveloped	48,111	22,625	11,899	6,710	3,915	9.20
Total Proved Reserves	65,108	36,428	23,569	16,868	12,949	13.07
Probable Reserves	28,265	13,055	6,916	4,079	2,599	9.63
Total Proved plus Probable Reserves	93,373	49,483	30,485	20,947	15,548	12.09

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

After Income Taxes [1]					
	Discounted at %/year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	12,564	10,370	8,854	7,765	6,946
Developed Non-Producing	1,103	782	603	487	407
Undeveloped	36,916	17,043	8,842	4,920	2,827
Total Proved Reserves	50,583	28,195	18,299	13,172	10,180
Probable Reserves	21,448	9,785	5,105	2,966	1,864
Total Proved plus Probable Reserves	72,031	37,980	23,404	16,138	12,044

Note:

(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 our Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2013.

Total Future Net Revenue (undiscounted) at December 31, 2013 (Forecast Prices and Costs) ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs [1]	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves	169,590	37,328	48,065	17,795	1,294	65,108	14,525	50,583
Proved plus Probable Reserves	243,782	54,094	68,067	26,731	1,517	93,373	21,342	72,031

Note:

(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 at December 31, 2013 (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	16,758	11.90
	Heavy Oil	2,589	17.17
	Light & Medium Oil and NGLs	2,723	27.72
	Natural Gas	1,499	10.25
	Total	23,569	13.07
Proved plus Probable Reserves	Bitumen	20,760	10.76
	Heavy Oil	4,192	16.27
	Light & Medium Oil and NGLs	3,558	25.33
	Natural Gas	1,975	10.21
	Total	30,485	12.09

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 our risk management activities.
- For disclosure purposes, we have 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 us.
4. **Gross** means: (a) in relation to wells, the total number of wells in which we have an interest; and (b) in relation to properties, the total area of properties in which we have an interest.
5. **Net** means: (a) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and (b) in relation to our interest in a property, the total area in which we have an interest multiplied by our 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 our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any reserves related to other royalty interests, such as overriding royalties, to which we are entitled.

8. **Royalty Interest Production** means the production related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any production related to other royalty interests, such as overriding royalties, to which we are 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, 2014 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2014. For historical prices realized during 2013, 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)**
2014	95.00	95.00	89.30	67.50	76.50	4.00	2.0	0.950
2015	95.00	96.50	90.70	70.40	79.60	4.25	2.0	0.950
2016	95.00	97.50	91.70	71.20	80.40	4.55	2.0	0.950
2017	95.00	98.00	92.10	71.50	80.90	4.75	2.0	0.950
2018	95.30	98.30	92.40	71.80	81.10	5.00	2.0	0.950
2019	96.60	99.60	93.60	72.70	82.20	5.25	2.0	0.950
2020	98.50	101.60	95.50	74.20	83.80	5.35	2.0	0.950
2021	100.50	103.60	97.40	75.60	85.50	5.45	2.0	0.950
2022	102.50	105.70	99.40	77.20	87.20	5.55	2.0	0.950
2023	104.60	107.90	101.40	78.80	89.00	5.65	2.0	0.950
2024	106.70	110.00	103.40	80.30	90.80	5.75	2.0	0.950
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.950

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)	**2014**	**2015**	**2016**	**2017**	**2018**	**Remainder**	**Total**
Proved Reserves	1,502	1,115	1,172	754	1,107	12,145	17,795
Proved plus Probable Reserves	1,602	1,468	1,582	1,328	1,524	19,227	26,731

We believe that internally generated cash flows, existing credit facilities and access to capital markets will be sufficient to fund our future development costs. However, there can be no guarantee that the necessary funds will be available or that we will allocate funding to develop all of our reserves. Failure to develop those reserves would have a negative impact on our 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. We do not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of our Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2013, 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)
December 31, 2012	1,717	184	115	955
Extensions and Improved Recovery	134	21	11	24
Discoveries	-	-	-	-
Technical Revisions	32	(12)	6	76
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(5)	-
Production (1)	(37)	(14)	(12)	(190)
December 31, 2013	1,846	179	115	865

Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	676	105	56	338
Extensions and Improved Recovery	28	55	-	5
Discoveries	78	-	-	-
Technical Revisions	(99)	(20)	(4)	(43)
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(2)	-
Production (1)	-	-	-	-
December 31, 2013	683	140	50	300

Proved plus Probable	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	2,393	289	171	1,293
Extensions and Improved Recovery	162	76	11	29
Discoveries	78	-	-	-
Technical Revisions	(67)	(32)	2	33
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(7)	-
Production (1)	(37)	(14)	(12)	(190)
December 31, 2013	2,529	319	165	1,165

Note:
(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 our 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 eight and six percent, respectively. Increases at Christina Lake were primarily a result of receiving approval to expand the development area and planned increases to future well density. Increases at Foster Creek were primarily a result of development area expansion.

Heavy oil proved reserves decreased by approximately three percent primarily as a result of production exceeding expanded polymer flood and infill drilling areas at Pelican Lake. Heavy oil probable reserves increased by approximately 33 percent also primarily based on expanding pad development using increased well density at Pelican Lake. Overall, heavy oil proved plus probable reserves increased by approximately 10 percent.

Light and medium oil and NGLs proved reserves remained unchanged, with production being offset by expanding waterflood and CO_2 flood areas and their successful performance at Weyburn. Light and medium oil and NGLs probable reserves decreased by approximately 11 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 decreased by approximately four percent, primarily as a result of additions being offset by production and the Lower Shaunavon disposition.

Natural gas proved reserves declined by approximately nine percent as extensions and technical revisions did not offset production. Probable natural gas reserves and proved plus probable natural gas reserves declined by approximately 11 percent and 10 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 50 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	1,108	1,008	60	45	50	27	300	36
2011	325	1,287	13	55	3	25	-	24
2012	284	1,532	20	61	3	22	-	6
2013	158	1,629	1	47	3	15	-	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	804	506	43	37	28	21	54	30
2011	113	467	14	47	1	22	-	35
2012	182	646	9	42	5	24	-	16
2013	145	649	56	86	1	17	-	16

Development of Proved Undeveloped Reserves

Bitumen

At the end of 2013, we had proved undeveloped bitumen reserves of 1,629 million barrels Before Royalties, or approximately 88 percent of our total proved bitumen reserves. Of our 683 million barrels of probable bitumen reserves, 649 million barrels, or approximately 95 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. Our 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 Grand Rapids or 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 10 years.

Oil

We have 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 well over 40 years, with drilling of supplementary wells taking place over the next five years, and CO_2 flood advancement continuing many years beyond that. At Pelican Lake, investment in proved undeveloped reserves is projected to continue for 25 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

We retain McDaniel to evaluate and prepare reports on all of our 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 for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property, in the Greater Pelican Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region. McDaniel also tests contingent resources for economic viability using the same forecast prices and costs used for our reserves (refer to "Pricing Assumptions" in this AIF).

This evaluation assumes that the vast majority of our bitumen resources will be recovered and produced using SAGD, with only a minor portion of our 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. We have no bitumen resources that require mining techniques for recovery.

All of our current contingent and prospective resources are associated with clastic or sandstone formations. We have also identified significant amounts of bitumen in the Grosmont carbonate formation for which we have 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.
>
> **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 2013 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 our disclosed economic contingent resources do not include economic contingencies.

Our 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, we have 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 these applications 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, we submitted an application for a development project at the Telephone Lake property which, if approved, is expected to enable 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, we submitted an application in the fourth quarter of 2011 for initial development project approval at the Grand Rapids property. We expect to receive regulatory approval in the first quarter of 2014. Pilot project work is underway to examine optimal development strategies.

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, 2013**	December 31, 2012
Economic Contingent Resources (1)		
Low Estimate	7.0	7.1
Best Estimate	9.8	9.6
High Estimate	13.6	12.8
Prospective Resources (2)		
Low Estimate	4.5	5.0
Best Estimate	7.5	8.5
High Estimate	12.6	14.8

Notes:
(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 increased 0.2 billion barrels or two percent compared to 2012. This increase is primarily a result of stratigraphic test well drilling successfully converting prospective resources to contingent resources, the net acquisition of contingent resources through a property exchange, offset by the reduction of recovery factors at Steepbank and portions of the Grand Rapids formation and the loss of contingent resources due to the cancellation of mineral rights by the Alberta government for future urban development. Refer to "Risk Factors – Environment & Regulatory Risks – Alberta's Land-Use Framework" for more information.

Bitumen best estimate prospective resources declined 1.0 billion barrels or approximately 11 percent compared to 2012, primarily due to stratigraphic drilling, dispositions and cancellation of mineral rights by the Alberta government.

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)**
December 31, 2012	2.393	9.6	8.5
Transfers between Categories			
Additions from other resource categories	0.113	0.4	(0.4)
Reductions to other resource categories	-	(0.1)	-
Additions and Revisions Net of Transfers	0.060	(0.3)	(0.3)
Net Acquisitions and Dispositions	-	0.2	(0.3)
Production	(0.037)	-	-
December 31, 2013	2.529	9.8	7.5

Notes:
(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.

We are systematically progressing the classification of our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, the stratigraphic well drilling program in the Steepbank 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.

Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to continue to improve overall recovery from our bitumen assets as technology develops.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following tables summarize our interests in producing and non-producing wells, at December 31, 2013:

Producing Wells (1) (2)

	Oil		Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	338	171	299	299	637	470
Conventional	2,508	2,461	24,568	24,371	27,076	26,832
Total Alberta	2,846	2,632	24,867	24,670	27,713	27,302
Saskatchewan	709	451	-	-	709	451
Total	3,555	3,083	24,867	24,670	28,422	27,753

Notes:
(1) Cenovus also has varying royalty interests in 9,093 natural gas wells and 3,671 crude oil wells which are producing.
(2) Includes wells containing multiple completions as follows: 22,455 gross natural gas wells (22,287 net wells) and 1,127 gross crude oil wells (1,002 net wells).

Non-Producing Wells (1)

	Oil		Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	47	27	508	432	555	459
Conventional	830	794	768	742	1,598	1,536
Total Alberta	877	821	1,276	1,174	2,153	1,995
Saskatchewan	127	84	7	7	134	91
Total	1,004	905	1,283	1,181	2,287	2,086

Note:
(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 our gross participation and net interest in wells drilled for the periods indicated:

Exploration Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Gross**	**Net**
2013:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	6	6	-	-	-	-	6	6	9	15	6
Total Canada	6	6	-	-	-	-	6	6	9	15	6
2012:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	8	7	-	-	-	-	8	7	20	28	7
Total Canada	8	7	-	-	-	-	8	7	20	28	7
2011:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	24	22	-	-	2	2	26	24	40	66	24
Total Canada	24	22	-	-	2	2	26	24	40	66	24

Development Wells Drilled	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2013:											
Oil Sands	91	46	-	-	-	-	91	46	3	94	46
Conventional	215	206	-	-	2	2	217	208	117	334	208
Total Canada	306	252	-	-	2	2	308	254	120	428	254
2012:											
Oil Sands	61	31	-	-	-	-	61	31	57	118	31
Conventional	349	345	-	-	1	1	350	346	129	479	346
Total Canada	410	376	-	-	1	1	411	377	186	597	377
2011:											
Oil Sands	40	20	3	3	-	-	43	23	87	130	23
Conventional	343	334	66	65	4	4	413	403	156	569	403
Total Canada	383	354	69	68	4	4	456	426	243	699	426

During the year ended December 31, 2013, Oil Sands drilled 339 gross stratigraphic test wells (210 net wells) and Conventional drilled 54 gross stratigraphic test wells (54 net wells).

During the year ended December 31, 2013, Oil Sands drilled 27 gross service wells (17 net wells) and Conventional drilled 80 gross service wells (75 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 our landholdings at December 31, 2013:

Landholdings	Developed		Undeveloped (1)		Total (2)	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown (3)	483	382	1,824	1,368	2,307	1,750
Conventional						
– Fee (4)	1,933	1,933	440	440	2,373	2,373
– Crown (3)	1,150	1,046	747	683	1,897	1,729
– Freehold (5)	71	60	15	14	86	74
Total Alberta	3,637	3,421	3,026	2,505	6,663	5,926
Saskatchewan:						
Oil Sands						
– Crown (3)	-	-	64	64	64	64
Conventional						
– Fee (4)	80	80	426	426	506	506
– Crown (3)	48	33	180	162	228	195
– Freehold (5)	14	10	7	3	21	13
Total Saskatchewan	142	123	677	655	819	778
Manitoba:						
Conventional – Fee (4)	4	4	263	263	267	267
Total Manitoba	4	4	263	263	267	267
Total	3,783	3,548	3,966	3,423	7,749	6,971

Notes:

(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) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.

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

(4) Fee lands are those lands in which we have 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 us 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

We have approximately 4.0 million gross acres (3.4 million net acres) of properties to which no reserves have been specifically attributed. These properties are planned for current and future development in both our oil sands and conventional oil and gas operations. There are currently no work commitments on these properties.

We have rights to explore, develop, and exploit approximately 88,000 net acres that could potentially expire by December 31, 2014, which relate entirely to Crown and freehold land.

For areas where we hold interests in different formations under the same surface area through separate leases, we have calculated our 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 uncertainty factors relevant to our 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 our working interest and the estimated timing of the costs to be incurred in future periods. We have 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.

We have estimated the undiscounted future cost of abandonment and reclamation costs at approximately $7.5 billion (approximately $1.3 billion, discounted at 10 percent) at December 31, 2013, of which we expect to pay approximately $322 million in the next three financial years. We expect to incur these costs on approximately 35,185 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of our proved reserves, approximately $1.3 billion has been deducted in estimating the future net revenue, which only represents our downhole abandonment obligations for wells within reserves.

Tax Horizon

We expect to pay income tax in 2014.

Costs Incurred

($ millions)	**2013**
Acquisitions	
– Unproved	32
– Proved	-
Total acquisitions	32
Exploration costs	264
Development costs	2,763
Total costs incurred	3,059

Forward Contracts

We may use financial derivatives to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in the notes to our annual audited Consolidated Financial Statements for the year ended December 31, 2013.

Production Estimates

The following table summarizes the estimated 2014 average daily volume of Company Interest Before Royalties and Royalty Interest Production reflected in the reserves reports for all properties held on December 31, 2013 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.

2014 Estimated Production Forecast Prices and Costs	**Proved**	**Proved plus Probable**
Bitumen (bbls/d) [(1)]	121,175	124,587
Light and Medium Oil (bbls/d)	41,964	43,935
Heavy Oil (bbls/d)	30,826	32,798
Natural Gas (MMcf/d)	431	450
Natural Gas Liquids (bbls/d)	735	819
Company Interest Before Royalties Production (BOE/d)	266,498	277,130
Royalty Interest Production (BOE/d)	6,450	6,795
Total Company Interest Before Royalties Plus Royalty Interest Production (BOE/d)	272,948	283,925

Note:
(1) Includes Foster Creek production of 56,375 bbls/d for Proved and 56,387 bbls/d for Proved plus Probable, and Christina Lake production of 64,800 bbls/d for Proved and 68,200 bbls/d for Proved plus Probable.

Production History

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

Note:
(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

Note:
(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

Note:
(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

Note:
(1) Natural gas liquids include condensate volumes.

Average Before Royalties Daily Production Volumes – 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	54,868	55,045	56,322	50,373	57,744
Christina Lake (Bitumen)	11,665	19,531	10,067	7,880	9,084
	66,533	74,576	66,389	58,253	66,828
Conventional Liquids					
Heavy Oil – Pelican Lake	20,424	20,558	20,363	19,427	21,360
Heavy Oil – Other	14,397	14,275	14,191	14,038	15,096
Light and Medium Oil	26,513	29,011	26,470	23,361	27,190
Natural Gas Liquids (1)	935	915	897	934	994
Total Crude Oil and Natural Gas Liquids	128,802	139,335	128,310	116,013	131,468
Natural Gas (MMcf/d)					
Oil Sands	34	36	37	34	29
Conventional	599	599	599	598	596
Total Natural Gas	633	635	636	632	625
Total (BOE/d)	234,302	245,168	234,310	221,346	235,635

Note:
(1) Natural gas liquids include condensate volumes.

Average Royalty Interest Daily Production Volumes - 2011					
	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil – Other	1,260	1,237	1,114	1,340	1,351
Light and Medium Oil	4,011	3,519	3,929	4,256	4,349
Natural Gas Liquids (1)	166	182	143	153	187
Total Crude Oil and Natural Gas Liquids	5,437	4,938	5,186	5,749	5,887
Natural Gas (MMcf/d)					
Conventional	23	25	20	22	27
Total (BOE/d)	9,270	9,105	8,519	9,416	10,387

Note:
(1) Natural gas liquids include condensate volumes.

Per-Unit Results

The following tables summarize our 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 – 2013					
	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 ($/bbl) (1)					
Price	59.10	51.34	81.16	61.88	44.01
Royalties	3.50	3.37	5.68	3.40	1.57
Transportation and blending	2.93	3.25	3.76	1.82	2.69
Operating	14.19	13.04	14.26	16.45	13.53
Netback	38.48	31.68	57.46	40.21	26.22
Heavy Oil – Pelican Lake ($/bbl) (1)					
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
Total Heavy Oil – Conventional ($/bbl) (1)					
Price	70.31	64.55	87.50	71.73	57.42
Royalties	6.08	5.31	8.83	5.50	4.65
Transportation and blending	2.60	2.69	2.51	2.58	2.63
Operating	19.32	19.76	18.51	20.30	18.72
Production and mineral taxes	0.13	0.05	0.21	0.12	0.13
Netback	42.18	36.74	57.44	43.23	31.29
Total Heavy Oil ($/bbl) (1)					
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

Per-Unit Results – 2013					
	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

Notes:

(1) 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 annual cost of condensate for 2013 is as follows: Foster Creek – $42.41/bbl; Christina Lake – $45.25/bbl; Heavy Oil – Oil Sands – $43.77/bbl; Pelican Lake – $15.59/bbl; Heavy Oil – Conventional – $14.60/bbl; and Total Heavy Oil – $35.63/bbl.

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

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

Impact of Realized Financial Hedging – 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					
	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

Per-Unit Results – 2012					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
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) (1)					
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 ($/bbl) (1)					
Price	69.23	64.37	66.75	66.42	78.50
Royalties	3.34	2.82	4.34	2.68	3.37
Transportation and blending	2.15	1.23	1.09	3.54	2.88
Operating	17.08	17.20	17.47	17.71	16.05
Netback	46.66	43.12	43.85	42.49	56.20
Total Heavy Oil - Conventional ($/bbl) (1)					
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 ($/bbl) (1)					
Price	62.05	56.22	62.45	60.13	70.08
Royalties	5.83	4.07	7.96	3.68	7.56
Transportation and blending	2.67	2.60	2.50	2.79	2.82
Operating	13.56	12.33	13.66	13.80	14.65
Production and mineral taxes	0.03	0.04	0.03	0.03	0.02
Netback	39.96	37.18	38.30	39.83	45.03
Light and Medium Oil ($/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

Per-Unit Results – 2012					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
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

Notes:

(1) 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 annual cost of condensate for 2012 is as follows: Foster Creek − $41.85/bbl; Christina Lake − $45.83/bbl; Heavy Oil – Oil Sands − $43.26/bbl; Pelican Lake − $15.55/bbl; Heavy Oil – Conventional − $14.66/bbl; and Total Heavy Oil − $34.44/bbl.

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

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

Impact of Realized Financial Hedging – 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

Per-Unit Results – 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl) (1) (2)					
Price	67.38	75.96	62.68	72.23	59.50
Royalties	10.82	15.81	12.38	2.30	11.92
Transportation and blending	3.04	3.20	2.73	2.82	3.41
Operating	11.34	11.31	11.11	11.57	11.40
Netback	42.18	45.64	36.46	55.54	32.77
Heavy Oil – Christina Lake ($/bbl) (1) (2)					
Price	61.86	66.69	54.52	67.06	54.67
Royalties	3.03	2.97	2.87	3.98	2.44
Transportation and blending	3.53	2.98	4.54	3.51	3.69
Operating	20.20	17.96	23.01	23.41	19.09
Netback	35.10	42.78	24.10	36.16	29.45
Total Heavy Oil – Oil Sands ($/bbl) (1)					
Price	66.47	73.75	61.66	71.46	58.82
Royalties	9.55	12.75	11.20	2.53	10.59
Transportation and blending	3.12	3.15	2.95	2.92	3.45
Operating	12.79	12.90	12.60	13.24	12.48
Netback	41.01	44.95	34.91	52.77	32.30
Heavy Oil – Pelican Lake ($/bbl) (1)					
Price	73.07	88.67	66.76	78.26	64.66
Royalties	7.91	6.98	8.23	7.40	8.63
Transportation and blending	4.14	12.19	1.87	2.02	2.44
Operating	14.86	16.49	14.31	13.40	15.35
Netback	46.16	53.01	42.35	55.44	38.24

Per-Unit Results – 2011	Year	Q4	Q3	Q2	Q1
Total Heavy Oil – Conventional ($/bbl) [(1)]					
Price	73.57	85.06	67.26	78.36	66.59
Royalties	9.20	9.42	9.52	9.12	8.80
Transportation and blending	2.83	6.74	1.84	1.49	1.84
Operating	14.36	16.41	13.51	13.52	14.25
Production and mineral taxes	0.14	0.17	0.07	0.11	0.22
Netback	47.04	52.32	42.32	54.12	41.48
Total Heavy Oil ($/bbl) [(1)]					
Price	68.98	77.16	63.69	73.98	61.80
Royalties	9.42	11.74	10.59	4.93	9.91
Transportation and blending	3.02	4.23	2.55	2.40	2.83
Operating	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	0.05	0.05	0.03	0.04	0.08
Netback	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil ($/bbl)					
Price	85.40	90.90	79.57	94.30	77.39
Royalties	11.54	12.12	10.74	12.82	10.58
Transportation and blending	2.00	1.99	1.90	2.22	1.92
Operating	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	2.27	2.63	2.40	2.77	1.32
Netback	55.21	59.04	50.16	63.53	48.71
Total Crude Oil ($/bbl)					
Price	72.80	80.49	67.37	78.71	65.32
Royalties	9.92	11.83	10.62	6.77	10.06
Transportation and blending	2.78	3.69	2.40	2.35	2.63
Operating	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	0.57	0.67	0.58	0.67	0.36
Netback	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids ($/bbl)					
Price	76.84	82.26	74.38	80.32	70.67
Royalties	1.34	1.51	1.06	1.87	0.93
Netback	75.50	80.75	73.32	78.45	69.74
Total Liquids ($/bbl)					
Price	72.84	80.50	67.43	78.72	65.37
Royalties	9.84	11.75	10.55	6.72	9.98
Transportation and blending	2.76	3.66	2.38	2.33	2.60
Operating	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	0.56	0.67	0.57	0.67	0.36
Netback	46.21	50.29	40.77	55.87	39.00
Total Natural Gas ($/Mcf)					
Price	3.65	3.35	3.72	3.71	3.82
Royalties	0.06	0.06	0.05	0.04	0.08
Transportation and blending	0.15	0.14	0.15	0.14	0.17
Operating	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	0.04	0.01	0.03	0.05	0.06
Netback	2.30	1.92	2.50	2.50	2.32
Total ($/BOE)					
Price	49.75	53.48	46.97	51.81	46.83
Royalties	5.55	6.65	5.91	3.64	5.85
Transportation and blending	1.91	2.39	1.70	1.61	1.92
Operating	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	0.41	0.40	0.39	0.49	0.36
Netback	31.53	32.95	29.09	36.38	28.02

Notes:

(1) 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 annual cost of condensate for 2011 is as follows: Foster Creek – $41.74/bbl; Christina Lake – $47.07/bbl; Heavy Oil – Oil Sands – $42.61/bbl; Pelican Lake – $16.32/bbl; Heavy Oil – Conventional – $14.69/bbl; and Total Heavy Oil – $32.76/bbl.

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

Impact of Long-term Incentive Costs (Recovery) on Operating Costs – 2011	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.17	0.33	(0.47)	(0.32)	1.11

Impact of Realized Financial Hedging - 2011	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas ($/Mcf)	0.87	1.10	0.76	0.74	0.89
Total ($/BOE)	0.86	1.22	2.49	(1.25)	0.83

Capital Expenditures, Acquisitions and Divestitures

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

We also have an active program to divest of non-core assets, in order to increase our focus on our key assets within the long range business plan as well as generate proceeds to partially fund our capital investment. Early in the third quarter, we completed the sale of our Lower Shaunavon tight oil asset located in southern Saskatchewan for proceeds of approximately $240 million plus closing adjustments. Immediately prior to the disposition, Lower Shaunavon was producing an average of 3,592 bbls/d during the second quarter of 2013.

The following table summarizes our net capital investment for 2013 and 2012:

Net Capital Investment ($ millions)	**2013**	**2012**
Capital Investment		
Oil Sands		
Foster Creek	797	735
Christina Lake	688	593
Total	1,485	1,328
Other Oil Sands	398	365
	1,883	1,693
Conventional		
Pelican Lake	465	518
Other Conventional	726	848
	1,191	1,366
Refining and Marketing	107	118
Corporate	81	191
Capital Investment	3,262	3,368
Acquisitions	32	114
Divestitures	(283)	(76)
Net Acquisition and Divestiture Activity	(251)	38
Net Capital Investment	3,011	3,406

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

Our 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 us to remove or remedy the effect of our 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 our 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.

We recognize that there is a cost associated with carbon emissions and we believe 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 our future planning, management and the Board review the impact of a variety of carbon constrained scenarios on our 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, we will continue to assess and evaluate the cost of carbon relative to our 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".

We also examine the impact of carbon regulation on our major projects, including our oil sands operations and our refining assets. We continue to closely monitor potential GHG legislation developments both in Canada and the U.S.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2013, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. We do not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2014. Refer to "Risk Factors – Environment & Regulatory Risks – Environmental Regulations" for further information on environmental protection matters affecting Cenovus.

Corporate Responsibility Practice

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

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. Our 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 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 will strive to never compromise the health and 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.

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 we have 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 our progress; (iii) an energy efficiency program that focuses on reducing energy use at our 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 our 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; and (viii) a requirement for acknowledgement and sign-off on key policies and practices by our Board and employees. Our 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 listed Cenovus to their Global 100 clean capitalism ranking for the second consecutive year. Corporate Knights also recognized Cenovus's leading CR performance in their inaugural Top 10 Energy Companies in the World listing, published in November 2013.

In October 2013, Cenovus was named to the Canada 200 Climate Disclosure Leadership Index, which recognizes companies for their open and transparent disclosure of greenhouse gas emissions, for the fourth 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 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year and to the Dow Jones Sustainability North America Index for the fourth consecutive year. The Dow Jones Sustainability Indexes track the financial performance of the leading companies worldwide regarding CR performance. In June 2013, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada. These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

Employees

The following table summarizes our full-time equivalent ("FTE") employees at December 31, 2013:

	FTE Employees
Oil Sands	1,385
Conventional	704
Refining and Marketing	69
Cenovus-wide	1,386
Total	3,544

We also engage a number of contractors and service providers. Refer to "Risk Factors – Operational Risks – Personnel" for further information on employee matters affecting Cenovus.

Foreign Operations

We, and our reportable segments, are not dependent upon foreign operations outside North America. As a result, our 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 our control, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash. Refer to "Risk Factors – Financial Risks – Foreign Exchange Rates" for information on foreign exchange rate matters affecting Cenovus.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Cenovus.

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years
Ralph S. Cunningham [2,4,5,7] Houston, Texas, United States	2009	Mr. Cunningham is a director of Enterprise Products Holdings, LLC, the successor general partner of Enterprise Products Partners L.P., a publicly traded midstream energy limited partnership; and Chairman of TETRA Technologies, Inc., a publicly traded energy services and chemicals company. Mr. Cunningham served as Chairman of Enterprise Products Holdings, LLC from November 2010 to February 2013; 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; 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	Mr. Daniel is a director of Canadian Imperial Bank of Commerce and a member of the North American Review Board of American Air Liquide Holdings, Inc., 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.
Ian W. Delaney [2,4,5,7] Toronto, Ontario, Canada	2009	Mr. Delaney is Chairman of The Westaim Corporation, a publicly traded investment company and Dacha Strategic Metals Inc., a publicly traded investment company focused on the acquisition, storage and trading of strategic metals. 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.

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years
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 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)	Mr. Grandin is the Chair of our 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	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
Charles M. Rampacek [5,6,7] Dallas, Texas, United States	2009	Mr. Rampacek is a director of Flowserve Corporation, a publicly traded manufacturer of industrial equipment; Pilko & Associates L.P., a private chemical and energy advisory company; 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. 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	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	Mr. Thomson is a director and Chief Executive Officer of Iskander Energy Corp., a private international oil and gas company; Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves; and a director of TVI Pacific Inc., a publicly traded international mining company. Mr. Thomson served as a director of Virgin Resources Limited, a private international oil and gas company from January 2005 to April 2013. Mr. Thomson is a member of the Association of Professional Engineers and Geoscientists of Alberta.

Notes:
(1) Each of the directors became members of our Board pursuant to the Arrangement.
(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 our Board.
(9) Ex-officio, by standing invitation, non-voting member of all other committees of our 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, 2013.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Brian C. Ferguson Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Ferguson's biographical information is included under "Directors".
Ivor M. Ruste Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. Ruste 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 our Executive Vice-President (President, Integrated Oil Division). In 2009, Mr. Brannan held the following position with Encana: Executive Vice-President (President, Integrated Oil Division).
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 our 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 our Executive Vice-President, Communications & Stakeholder Relations. In 2009, Ms. McIntosh held the following position with Encana: Executive Vice-President, Corporate Communications.
Donald T. Swystun Calgary, Alberta, Canada	Executive Vice-President, Refining, Marketing, Transportation & Development Mr. Swystun became Executive Vice-President, Refining, Marketing, Transportation & Development on December 1, 2010 and held that position until December 31, 2013. From November 2009 to November 2010, Mr. Swystun was our Executive Vice-President (President, Canadian Plains Division). In 2009, Mr. Swystun held the following position with Encana: Executive Vice-President (President, Canadian Plains Division).

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Hayward J. Walls Calgary, Alberta, Canada	Executive Vice-President, Organization & Workplace Development Mr. Walls became Executive Vice-President, Organization & Workplace Development on November 30, 2009. In 2009, Mr. Walls held the following position with Encana: Executive Vice-President, Corporate Services.

As of December 31, 2013, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,086,121 Common Shares or approximately 0.14 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of our 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 our knowledge, none of our current directors or executive officers is, as at the date of this AIF, or has 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 our knowledge, other than as described below, none of our 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 our knowledge, none of our 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 our Audit Committee.

Pre-Approval Policies and Procedures

We have 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, 2013 and 2012:

($ thousands)	**2013**	**2012**
Audit Fees (1)	2,460	2,598
Audit-Related Fees (2)	288	198
Tax Fees (3)	374	414
All Other Fees	57	43
Total	3,179	3,253

Notes:

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

(2) *Audit-Related Fees* consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees. The services provided in this category included audit-related services in relation to our debt shelf prospectuses, systems development and controls testing.

(3) *Tax Fees* consist of fees 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.

DESCRIPTION OF CAPITAL STRUCTURE

The following is a summary of the rights, privileges, restrictions and conditions which are attached to common shares ("Common Shares") and our first and second preferred shares (collectively the "Preferred Shares"). We are authorized to issue an unlimited number of Common Shares and an unlimited number of First Preferred Shares and Second Preferred Shares. As of December 31, 2013, there were approximately 756.0 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 our 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 our assets in the event of liquidation, dissolution or winding up or other distribution of our assets among our shareholders for the purpose of winding up our affairs.

Preferred Shares

Preferred Shares may be issued in one or more series. Our 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 we fail 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 our affairs. Our 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

We have a Shareholder Rights Plan that was adopted in 2009 to ensure, to the extent possible, that all our 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 our 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 acquiror, from and after the separation time (unless delayed by our 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 our shareholders at every third annual shareholder meeting.

Dividend Reinvestment Plan

We have 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.

Employee Stock Option Plan

Our Employee Stock Option Plan 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. Options granted on or after February 24, 2011 have associated net settlement rights. 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 our credit ratings is provided as it relates to our financing costs and liquidity. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on our debt by our rating agencies or a negative change in our ratings outlook could adversely affect our cost of financing and our access to sources of liquidity and capital. See "Risk Factors" in this AIF for further information.

The following table outlines the ratings and outlooks of Cenovus's debt as at December 31, 2013:

	Standard & Poor's Ratings Services ("S&P")	**Moody's Investors Service ("Moody's")**	**DBRS Limited ("DBRS")**
Senior unsecured Long-Term Rating	BBB+/Stable	Baa2/Stable	A (low)/Stable
Commercial Paper Short-Term Rating	A-1 (Low)/Stable	P-2/Stable	R-1 (low)/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 has satisfactory capacity to meet its financial commitments. A ratings outlook gives the potential direction of a short or long-term rating and the "stable" designation indicates that a rating is not likely to change.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade (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.

During the last two years, we have made payments to S&P, Moody's and DBRS related to the rating of our debt. Additionally, we have purchased products and services from S&P and Moody's.

DIVIDENDS

The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

The Board has approved a 10 percent increase in the first quarter dividend to $0.2662 per share payable on March 31, 2014 to holders of Common Shares of record as of March 14, 2014. Readers should also refer to risk factors "Risk Factors – Financial Risks – Ability to Pay Dividends" for additional information.

We paid the following dividends over the last three years:

Dividends Paid ($ per share)	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
2013	0.968	0.242	0.242	0.242	0.242
2012	0.880	0.220	0.220	0.220	0.220
2011	0.800	0.200	0.200	0.200	0.200

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 2013:

2013	**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	34.13	32.60	33.11	30,439	34.50	32.89	33.24	16,217
February	33.76	31.32	33.39	27,727	33.84	31.11	32.31	20,069
March	33.16	31.09	31.46	42,818	32.48	30.58	30.99	17,611
April	32.08	28.32	30.15	54,598	31.58	27.57	29.94	27,644
May	31.51	29.25	31.04	32,100	30.85	29.06	29.93	25,883
June	31.47	28.67	30.00	37,841	30.42	27.25	28.52	23,487
July	32.77	29.88	30.42	50,346	31.60	28.38	29.60	23,707
August	30.89	28.98	30.18	37,623	29.88	28.00	28.74	27,665
September	31.62	30.17	30.74	27,821	30.54	28.77	29.85	15,933
October	31.36	29.98	30.98	31,033	30.34	28.79	29.72	18,409
November	31.25	29.98	30.93	25,675	29.80	28.56	29.21	20,076
December	31.69	29.33	30.40	26,899	29.79	27.60	28.65	24,108

RISK FACTORS

Our 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 our operations. We have 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 our business, reputation, financial condition, results of operations and cash flow, which may reduce or restrict our ability to pay a dividend to our shareholders and may materially affect the market price of our securities.

Our approach to risk management includes compliance with our Board approved Enterprise Risk Management Policy and the related enterprise risk management framework and program. It includes an annual review of our principal and emerging risks, an analysis of the severity and likelihood of each principal risk, consideration of our current mitigation and an evaluation if additional mitigation or treatment of the risk is required. In addition, we continuously monitor our 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 our hedging activities; and risks related to our 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 our growth, financial strength of our counterparties, access to capital and cost of borrowing.

Commodity Price Volatility

Our 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. Our 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. Our refined products 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 our 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.

Our 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 our 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 our control.

The financial performance of our 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 our business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact the value of our assets, our ability to maintain our business and to fund growth projects including, but not limited to, the continued development of our oil sands properties. Prolonged periods of commodity price volatility may also negatively impact our ability to meet guidance targets and meet all of our 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 our refineries.

We conduct an annual assessment of the carrying value of our 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 our assets may be subject to impairment.

Development and Operating Costs

Our financial performance is significantly affected by the cost of developing and operating our 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

Our Market Risk Mitigation Policy, which has been approved by the Board, allows management to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refining margins. We also use derivative instruments in various operational markets to optimize our supply or production chain. We 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 us to risks which may cause significant loss. These risks include, but are not limited to: changes in the price of the hedge instrument that are not reflected in the price of the products we sell; failure by a counterparty to perform an obligation; human error or deficiency in our systems or controls; and the unenforceability of our contracts.

Additionally, the consequences of hedging to protect against downside price risk may limit the benefit to us of commodity price increases or changes in interest rates and foreign exchange rates. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil, natural gas or refined products to fulfill our delivery obligations.

Exposure to Counterparties

In the normal course of business we enter 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, we may suffer financial losses, may have to delay our development plans or may have to forego other opportunities which may materially impact our financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. An inability to access capital could affect our ability to make future capital expenditures and to meet all of our financial obligations as they come due. Our ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular.

As at December 31, 2013, Cenovus had US$4.75 billion in debt outstanding with no principal payments due until October 2019 (US$1.3 billion). We have a $3.0 billion committed credit facility, with a maturity of November 30, 2017, of which the entire amount was available at December 31, 2013, to meet operating and capital requirements. Going forward, an inability to access the credit markets, a sustained downturn in the prices of crude oil or refined products or the continued downturn in the price of natural gas or significant unanticipated expenses related to development and maintenance of our existing properties could negatively impact our liquidity, our credit ratings and our ability to access additional sources of capital. We are also required to comply with various financial and operating covenants under our credit facilities and the indentures governing our debt securities. We routinely review the covenants and may make changes to our development plans, dividend policy, or may take alternative actions to ensure compliance. In the event that we do not comply with such covenants, our 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, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may affect our results as global prices for crude oil, natural gas and refined products are set in U.S. dollars, while many of our operating and capital costs as well as our 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 our oil, natural gas and refined products. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar creates uncertainty and impacts our capital expenditures and expenses.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities. An increase in interest rates could increase our net interest expense and negatively impact our financial results. Additionally, we are 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 our Board. All dividends will be reviewed by the Board and may be increased, reduced or suspended from time to time. Our ability to pay dividends and the actual amount of such dividends is dependent upon, among other things, our financial performance, our debt covenants and obligations, our ability to meet our financial obligations as they come due, our working capital requirements, our future tax obligations, our future capital requirements and the risk factors set forth in this AIF.

Operational Risks

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. In general, our operations are subject to general risks affecting the oil and gas industry. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation 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 our 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 our 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

Our production is transported through various pipelines and our refineries are reliant on various pipelines to receive feedstock. Disruptions in, or restricted availability of pipeline service, could adversely affect our crude oil and natural gas sales, projected production growth, refining operations and our 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 our 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 the application 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 our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact our crude oil sales volumes or the price received for our product. Our 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, it could adversely affect our ability to ship crude oil by rail or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of our refinery customers may limit our ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

Our 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. Our oil operations are susceptible to loss of production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of our 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.

Our 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.

We do not insure against all potential occurrences and disruptions and it cannot be guaranteed that our insurance will be sufficient to cover any such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our 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 our 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. Our actual production, revenues, taxes and development and operating expenditures with respect to our 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 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 and therefore our 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 our upstream and refining projects. These risks include, but are not limited to, our 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; the accuracy of project cost estimates; our ability to finance growth; our 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 our existing asset base could cause delays in achieving targets and objectives.

Partner Risks

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

Interests in certain of our upstream assets are held in a partnership with ConocoPhillips, an unrelated U.S. public company, and are operated by us. Our refining assets are held in a partnership with Phillips 66 and operated by Phillips 66. The success of our refining operations is dependent on the ability of Phillips 66 to successfully operate this business and maintain the refining assets. We rely on the judgment and operating expertise of Phillips 66 in respect of the operation of such refining assets and we also rely on Phillips 66 to provide us with 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 our 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 our participation in the operation of such assets, our 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. We compete with other producers and refiners, some of which may have lower operating costs or greater resources than we do. Competing producers may develop and implement recovery techniques and technologies which are superior to those we employ. 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 and increase our 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 our 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, we may be the subject of litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate. The outcome of such litigation may materially impact our financial condition or results of operations. We may be required to incur significant expenses or devote significant resources in defence 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 our business. In particular, aboriginal groups have claimed aboriginal title and rights to a substantial portion of western Canada. 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.

Personnel

Our success is dependent upon our management and the quality of our personnel. Failure to retain current personnel or to attract and retain new personnel with the necessary skills and competencies could have a material adverse effect on our growth and profitability.

Information Systems

We depend on a variety of information systems to operate effectively. A failure 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.

Environment & Regulatory Risks

Our 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 our 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 our existing and planned projects.

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we 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 our 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

Our 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 we are charged on our oil sands production is determined based on the Canadian dollar equivalent price of WTI, and therefore increases in WTI or decreases in the CDN$/US$ exchange rate could significantly increase our royalties, which may have a negative impact on our business, financial conditions, results of operations and cash flow. There is also a mineral tax in each province levied on hydrocarbon production from lands which the Crown does not own the mineral rights. The potential for changes in the royalty and mineral tax regimes applicable in the provinces we operate 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 our 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 our 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 us and our shareholders. Tax authorities having jurisdiction over us or our shareholders may disagree with the manner in which we calculate our tax liabilities or could change their administrative practices to our detriment or the detriment of our 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 our 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 our 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 our 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 our suppliers and service providers.

Adverse impacts to our business if comprehensive GHG legislation or regulation is enacted and applies to our business in any jurisdiction in which we operate or conduct 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 we produce; 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 our 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 us.

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 our bitumen, crude oil or refined products, and require us 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. We believe that we are well positioned within the sector given our historically low steam to oil ratio.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. Of specific note is the Energy Independence & 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 require 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., 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 they produce and, consequently, we are 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. Our 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. In 2013, we received compensation of $20 million, including interest, 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 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 recently announced 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. Public consultations are currently in progress and the SSRP is expected to be implemented starting in 2015. 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.

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.

Alberta's Regulatory Enhancement Project

A comprehensive, multi-stakeholder review of Alberta's regulatory system, the Regulatory Enhancement Project, was initiated by the Government of Alberta in March 2010 with the intention of creating an effective regulatory system that contributes to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. As part of the implementation of the resulting recommendations, on October 24, 2012, the Government of Alberta introduced Bill 2, the Responsible Energy Development Act. With the intention to streamline and reduce costs of regulations of upstream energy resource activities, a single provincial regulator was introduced in June 2013, the AER, and is expected to take-over responsibilities from Alberta Environment and Sustainable Resource Development by March 2014. The AER has also assumed the regulatory functions of the Energy Resources Conservation Board with respect to oil, gas, oil sands and coal development.

During the transition period to the new single regulator, regulatory applications and proceedings have been delayed, which may negatively impact our development plans.

Alberta Environment and Sustainable Resource Development Water Licences

We currently utilize fresh water in certain operations, which is obtained under licenses from Alberta Environment and Sustainable Resource Development to provide, for example, domestic and utility water at our SAGD facilities and for our 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 we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us, or at all, or that such additional water will in fact be available to divert under such licenses.

Alberta Wetlands Policy

In September 2013, the Government of Alberta approved a new wetlands policy to be implemented in 2015. This new policy is not expected to affect our existing operations in Foster Creek, Christina Lake and Narrows Lake, where our ten year wetlands mitigation and monitoring plans were recently approved under the existing wetlands policy. However, new project developments and phase expansions may be affected by this new policy in 2015.

Under the new policy, wetlands will be ranked by significance, with new projects in high-ranking wetlands areas having to either avoid the area entirely or offset the disturbance by reclaiming another high-ranking wetlands area. As the methodology for ranking wetlands is still under development, we are unable to predict the total impact of the new policy on any planned future developments.

Reputation Risks

We rely on our reputation to build and maintain positive relationships with our stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that cause negative public opinion have the potential to negatively impact our reputation which may adversely affect our share price, our development plan and our 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 our 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 and reduce its price.

Other Risk Factors

Arrangement Related Risk

We have 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 our indemnity, the Cenovus business and assets. At the present time, we cannot determine whether we will have to indemnify Encana for any substantial obligations under the terms of the Arrangement. We also cannot assure that if Encana has to indemnify Cenovus and our 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 our business, prospects, financial condition, results of operation and cash flows, and in some cases our reputation, can be found in our 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, 2013, there were no legal proceedings to which we are or were a party, or that any of our property is or was the subject of, which is or was, or can be reasonably considered to be, material to us or any of our properties and we are not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2013, there were no penalties or sanctions imposed against us 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 us that would likely be considered important to a reasonable investor in making an investment decision, and we have 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 our 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 our outstanding voting securities, of which there are none that we are 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 us.

MATERIAL CONTRACTS

During the year ended December 31, 2013, we have not entered into any contracts, nor are there any contracts still in effect, that are material to our 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

Our independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 12, 2014 in respect of our Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2013, 2012, and 2011 and Cenovus's internal control over financial reporting as at December 31, 2013. 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 our 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 our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2013. Additional disclosure, including directors' and officers' remuneration, principal holders of our securities, securities authorized for issuance under our equity-based compensation plans and our statement of corporate governance practices, is included in our management proxy circular for our most recent annual meeting of shareholders.

Disclosure regarding the contribution of each reportable segment to revenues and earnings can be found in our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2013, which disclosure is incorporated by reference into this AIF.

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at cenovus.com, we are 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, 2013 unless otherwise indicated. Numbers presented are rounded to the nearest whole number and tables may not add due to rounding.

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

ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Bcf	billion cubic feet
bbls/d	barrels per day	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBtu	million British thermal units
BOE	barrel of oil equivalent	CBM	Coal Bed Methane
BOE/d	barrels of oil equivalent per day		
WTI	West Texas Intermediate		
TM	Trademark of Cenovus Energy Inc.		

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, 2013.

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 13, 2014	Canada	28,345
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation Janaury 10, 2014	Canada	2,140
			30,485

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 11, 2014

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, 2013, 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 12, 2014

APPENDIX C

AUDIT COMMITTEE MANDATE

I. PURPOSE

The Audit Committee (the "Committee") is a committee of the Board of Directors 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 of Directors.
- Report to the Board of Directors 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 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 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:

(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.

26. 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.

27. 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.

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

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

30. 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

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

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

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

Approval of Audit and Non-Audit Services

34. 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).

35. 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.

36. 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.

37. 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.

38. 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

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

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

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

42. 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.

43. 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.

44. 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.

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

46. 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.

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

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

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