Table of Contents

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

# FORM 40-F

[Check one]

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

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

**For the fiscal year ended: December 31, 2012** **Commission File Number: 1-34513**

# CENOVUS ENERGY INC.

(Exact name of Registrant as specified in its charter)

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

**Canada**
(Province or other jurisdiction of incorporation or organization)

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

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

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

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

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

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

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

**None**
(Title of Class)

Table of Contents

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

**None**
(Title of Class)

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

þ Annual information form þ Audited annual financial statements

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

755,842,760

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

Yes þ No o

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

Yes o No o

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933, as amended: Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-10 (File No. 333-181728).



Table of Contents

**Principal Documents**

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

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2012.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2012.

(c) Consolidated Financial Statements of Cenovus Energy Inc. as at December 31, 2012.

(d) Supplementary Information – Oil and Gas Activities (unaudited) as at December 31, 2012.



Table of Contents

cenovus ENERGY

# CENOVUS ENERGY INC.

**ANNUAL INFORMATION FORM**

Table of Contents

## TABLE OF CONTENTS


| | |
|---|---|
| FORWARD-LOOKING INFORMATION | 1 |
| CORPORATE STRUCTURE | 2 |
| GENERAL DEVELOPMENT OF OUR BUSINESS | 3 |
| NARRATIVE DESCRIPTION OF OUR BUSINESS | 6 |
| Oil Sands | 7 |
| Conventional | 10 |
| Refining and Marketing | 13 |
| RESERVES DATA AND OTHER OIL AND GAS INFORMATION | 15 |
| Disclosure of Reserves Data | 15 |
| Definitions | 18 |
| Reserves Reconciliation | 20 |
| Contingent and Prospective Resources | 23 |
| Other Oil and Gas Information | 26 |
| OTHER INFORMATION | 37 |
| Competitive Conditions | 37 |
| Environmental Considerations | 37 |
| Corporate Responsibility Practice | 37 |
| Employees | 38 |
| Foreign Operations | 38 |
| DIRECTORS AND EXECUTIVE OFFICERS | 39 |
| AUDIT COMMITTEE | 44 |
| DESCRIPTION OF CAPITAL STRUCTURE | 46 |
| DIVIDENDS | 48 |
| MARKET FOR SECURITIES | 48 |
| RISK FACTORS | 48 |
| LEGAL PROCEEDINGS AND REGULATORY ACTIONS | 58 |
| INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS | 58 |
| MATERIAL CONTRACTS | 58 |
| TRANSFER AGENTS AND REGISTRARS | 59 |
| ADDITIONAL INFORMATION | 59 |
| ABBREVIATIONS AND CONVERSIONS | 60 |

APPENDIX A - Report on Reserves Data by Independent Qualified Reserves Evaluators
APPENDIX B - Report of Management and Directors on Reserves Data and Other Information
APPENDIX C - Audit Committee Mandate

Table of Contents

## 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", "vision", "goal", "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 or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, anticipated finding and development costs, 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 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 www.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 liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; 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 EBITDA 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; 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 www.cenovus.com.



Table of Contents

## 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, reference to "we", "us", "our", "its", "Company" or "Cenovus" includes reference to subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries and, when in reference to prior period information, as held by Encana prior to the closing of the Arrangement.

Our principal 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, 2012:

| Subsidiaries & Partnerships | Percentage Owned[1] | Jurisdiction of Incorporation, Continuance, Formation or Organization |
|---|---|---|
| Cenovus FCCL 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 Partnership.
(3) Cenovus interest held indirectly 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, 2012.



Table of Contents

## GENERAL DEVELOPMENT OF OUR BUSINESS

Cenovus is a Canadian oil company headquartered in Calgary, Alberta. Our operations include oil sands properties and established crude oil and natural gas production in Alberta and Saskatchewan. We also have ownership interests in two refineries in Illinois and Texas, U.S.A.

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**, includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the 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 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.

### Three Year History

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

***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.



Table of Contents

- In the third quarter, phase D of Christina Lake achieved first production, approximately three months ahead of schedule. Total gross production for all phases 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 expected 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, the 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. Test runs of the CORE project have been successful and have resulted in a five percent increase to clean product yield. The Wood River Refinery's total processing capability of heavy crude oil is dependent on the quality of heavy Canadian crude oil that is economically available, and is expected to increase to 200,000 to 220,000 bbls/d.
- In the fourth quarter, Cenovus filed a joint application and Environmental Impact Assessment ("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.



Table of Contents

- 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.

***2010***

- In the second quarter, an application for the Narrows Lake project in the Christina Lake Region was submitted to the Energy Resources Conservation Board ("ERCB") and Alberta Environment. The project is jointly owned with ConocoPhillips and is expected to be developed in three phases with a total gross production capacity of 130,000 bbls/d of bitumen.
- In the third quarter, regulatory approval was received for Foster Creek phases F, G and H. Planned gross production capacity for each expansion phase was 30,000 bbls/d for a total gross production capacity of 90,000 bbls/d of bitumen.
- In the fourth quarter, we started up our Grand Rapids pilot project after receiving project approval from Alberta Environment. We had previously received project approval from the ERCB in the second quarter of 2010.



Table of Contents

## NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our upstream and refining assets as at December 31, 2012.






Table of Contents

**Overview**

All of our reserves and production are located in Canada, primarily within the provinces of Alberta and Saskatchewan. At December 31, 2012, we had a land base of approximately 7.0 million net acres and Company Interest Before Royalties proved reserves of approximately 1,717 million barrels of bitumen, 184 million barrels of heavy crude oil, 115 million barrels of light and medium crude oil and NGLs and 955 billion cubic feet of natural gas. The estimated proved reserves life index based on working interest production at December 31, 2012 was approximately 23 years. We also had Company Interest Before Royalties probable reserves of approximately 676 million barrels of bitumen, 105 million barrels of heavy crude oil, 56 million barrels of light and medium crude oil and NGLs and 338 billion cubic feet of natural gas at December 31, 2012.

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 heavy crude oil assets at Pelican Lake and new resource play assets including Grand Rapids and Telephone Lake plus the Athabasca natural gas assets. The Foster Creek and Christina Lake operations as well as the Narrows Lake property are jointly owned 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 2012, our Oil Sands capital investment was $2,211 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 258,000 bbls/d of bitumen with the addition of Christina Lake phase D in the third quarter of

2012 and completion of phase E, with first production expected in the third quarter of 2013. Overall construction of Christina Lake phase E is approximately 65% complete, while the central plant is approximately 87% complete. Pelican Lake capital investment for 2012 was primarily related to infill drilling to progress polymer flood, facilities expansions, pipeline construction and maintenance capital. We also continued to assess the potential of our new resource play assets during 2012 with our large stratigraphic test well program.

Plans for 2013 include the continued development of expansion phases at both Foster Creek and Christina Lake, site preparation and plant construction at Narrows Lake for phase A and infill drilling to progress the polymer flood, and facilities expansions at our Pelican Lake property. Plans also include the continuation of an active stratigraphic test well program on our new resource play assets and the continuation of pilot projects at our Grand Rapids and Telephone Lake properties.

At December 31, 2012, we held bitumen rights of approximately 1,469,000 gross acres (1,097,000 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, 2012:

| **Landholdings – Oil Sands** | **Developed Acreage** | | **Undeveloped Acreage** | | **Total Acreage** | | **Average Working** |
|---|---|---|---|---|---|---|---|
| (thousands of acres) | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Interest** |
| Foster Creek | 13 | 7 | 127 | 63 | 140 | 70 | 50% |
| Christina Lake | 6 | 3 | 33 | 16 | 39 | 19 | 50% |
| Pelican Lake | 102 | 102 | 291 | 286 | 393 | 388 | 99% |
| Narrows Lake | - | - | 26 | 13 | 26 | 13 | 50% |
| Telephone Lake | 3 | 3 | 144 | 144 | 147 | 147 | 100% |
| Athabasca | 417 | 345 | 454 | 380 | 871 | 725 | 83% |
| Other | 41 | 27 | 1,181 | 890 | 1,222 | 917 | 75% |
| Total | 582 | 487 | 2,256 | 1,792 | 2,838 | 2,279 | 80% |



Table of Contents

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) | **2012** | **2011** | **2012** | **2011** | **2012** | **2011** |
| Foster Creek | 57,833 | 54,868 | - | - | 57,833 | 54,868 |
| Christina Lake | 31,903 | 11,665 | - | - | 31,903 | 11,665 |
| Pelican Lake | 22,552 | 20,424 | - | - | 22,552 | 20,424 |
| Athabasca | - | - | 30 | 34 | 5,000 | 5,667 |
| Other | - | - | 3 | 3 | 500 | 500 |
| Total | 112,288 | 86,957 | 33 | 37 | 117,788 | 93,124 |

The following table summarizes our interests in producing wells at December 31, 2012. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2012:

| **Producing Wells – Oil Sands** | **Producing Oil Wells** | | **Producing Gas Wells** | | **Total Producing Wells** | |
|---|---|---|---|---|---|---|
| (number of wells) | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Foster Creek | 217 | 109 | - | - | 217 | 109 |
| Christina Lake | 65 | 33 | - | - | 65 | 33 |
| Pelican Lake | 515 | 515 | 7 | 7 | 522 | 522 |
| Athabasca | - | - | 293 | 280 | 293 | 280 |
| Other | - | - | 17 | 17 | 17 | 17 |
| Total | 797 | 657 | 317 | 304 | 1,114 | 961 |

*Foster Creek*

We have a 50 percent interest in Foster Creek, an oil sands property in northeast 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.

Development of expansion phases F, G and H at Foster Creek is progressing as planned with start-up from phase F expected in the third quarter of 2014. Cenovus expects to file an application with regulators in 2013 for an additional Foster Creek expansion, phase J. 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 2012, no wells using our Wedge Well™ technology were drilled (2011 – 10 wells) at Foster Creek. At December 31, 2012 there were 56 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 interest in Christina Lake, an oil sands property in northeast Alberta that uses SAGD technology and produces from the McMurray formation. Full capacity was reached at phase C in the second quarter, while phase D had first oil production in late July, approximately three months ahead of schedule. With the addition of phase D, gross production capacity at Christina Lake of 98,000 bbls/d was achieved in the first quarter of 2013. In 2011, we received regulatory approval for phases E, F and G which are expected to add approximately 140,000 bbls/d of gross production capacity. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and increase total gross production capacity by 10,000

bbls/d at each of phase F and phase G. With the addition of another four planned phases, we believe Christina Lake has potential gross production capacity of 288,000 bbls/d, increasing to as much as 300,000 bbls/d with optimization. In 2012, we drilled three wells (2011 – three wells) at Christina Lake using our Wedge Well™ technology and at December 31, 2012 there were six gross wells of this type producing.



Table of Contents

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. As steam is injected into the injector and producer wells at high pressure, 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 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 interest in Narrows Lake, an oil sands property within the Christina Lake Region in northeast Alberta. In the first quarter of 2010, we initiated the regulatory approval process for Narrows Lake by filing proposed terms of reference for an EIA and began public consultation for the project. In the second quarter of 2010, final terms of reference were issued by Alberta Environment and a joint application of the EIA was filed. 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. The project is expected to begin producing in 2017.

*Pelican Lake*

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 northeast Alberta. In 2012, our capital investment primarily related to infill drilling to progress the polymer flood, facilities expansions, pipeline construction and maintenance programs. In 2012, we drilled 76 heavy oil wells.

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 a major pipeline that transports crude oil from northern Alberta to crude oil markets.

*New Resource Play Assets*

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

*Grand Rapids*

Our Grand Rapids property is located in the Greater Pelican Region in northeast 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. During 2012, we continued to operate the pilot project at Grand Rapids and drilled the second well pair, which is currently steaming with production expected in the first quarter of 2013.

*Telephone Lake*

Our Telephone Lake property is located in the Borealis Region in northeast Alberta. A revised joint application and EIA was submitted in the fourth quarter of 2011 to the ERCB and Alberta Environment for the development of the property, including the construction of a facility with planned bitumen production capacity of 90,000 bbls/d. Portions of the Telephone Lake reservoir are overlain with non-



Table of Contents

saline water. To improve SAGD performance, this water should be removed in advance of SAGD operations. In the fourth quarter of 2012, a pilot program commenced to dewater a confined area and the results will be monitored throughout 2013.

*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 2012, 59 gross stratigraphic wells were drilled and 204 km of 2D seismic was shot.

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 up to 50 percent. In 2012, this rig was used to drill 15 stratigraphic wells and we plan to drill 20 wells in 2013. We also plan to build a second SkyStrat™ drilling rig in 2013.

*Athabasca Gas*

We produce natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeast 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 ERCB 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 19 million cubic feet per day in 2012 (2011 - 21 million cubic feet per day). The ADOE is providing

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 but is dependent on natural gas prices.

**Conventional**

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

At December 31, 2012, we had an established land position of approximately 4.9 million gross acres (4.7 million net acres), of which approximately 3.2 million gross acres (3.0 million net acres) are developed. The mineral rights on approximately 66 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 lands leased from the Province of Saskatchewan.

In 2012, our Conventional capital investment was $848 million and primarily focused on crude oil properties, including drilling, completion and major facilities work in Saskatchewan and tight oil opportunities in Alberta.

Plans for 2013 include oil focused capital investment to further develop our existing assets in Alberta and Saskatchewan. The spending will include additional drilling, well optimizations, well recompletions and investment in our existing facility infrastructure.



Table of Contents

The following table summarizes our landholdings at December 31, 2012:

| Landholdings – Conventional | Developed | | Undeveloped | | Total | | Average Working |
|---|---|---|---|---|---|---|---|
| (thousands of acres) | Gross | Net | Gross | Net | Gross | Net | Interest |
| Alberta | | | | | | | |
| Suffield | 914 | 904 | 131 | 129 | 1,045 | 1,033 | 99% |
| Brooks North | 571 | 569 | 8 | 8 | 579 | 577 | 100% |
| Langevin | 735 | 695 | 248 | 230 | 983 | 925 | 94% |
| Drumheller | 404 | 391 | 51 | 49 | 455 | 440 | 97% |
| Wainwright | 357 | 335 | 205 | 201 | 562 | 536 | 95% |
| NW Alberta | 32 | 7 | 128 | 102 | 160 | 109 | 68% |
| Saskatchewan | | | | | | | |
| Weyburn | 114 | 100 | 349 | 328 | 463 | 428 | 92% |
| Shaunavon / Bakken | 40 | 38 | 361 | 360 | 401 | 398 | 99% |
| Other | 9 | 6 | 19 | 19 | 28 | 25 | 89% |
| Manitoba | 4 | 4 | 262 | 262 | 266 | 266 | 100% |
| Total | 3,180 | 3,049 | 1,762 | 1,688 | 4,942 | 4,737 | 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) | 2012 | 2011 | 2012 | 2011 | 2012 | 2011 |
| Alberta | | | | | | |
| Suffield | 11,691 | 11,505 | 167 | 182 | 39,524 | 41,838 |
| Brooks North | 2,866 | 2,064 | 225 | 236 | 40,366 | 41,397 |
| Langevin | 7,719 | 7,361 | 109 | 118 | 25,886 | 27,028 |
| Drumheller | 3,653 | 2,298 | 54 | 61 | 12,653 | 12,465 |
| Wainwright | 4,417 | 4,251 | 3 | - | 4,917 | 4,251 |
| NW Alberta | 11 | 9 | 2 | 22 | 344 | 3,676 |
| Saskatchewan | | | | | | |
| Weyburn | 16,278 | 16,178 | - | - | 16,278 | 16,178 |
| Shaunavon / Bakken | 6,480 | 3,616 | 1 | - | 6,647 | 3,616 |
| Total | 53,115 | 47,282 | 561 | 619 | 146,615 | 150,449 |

The following table summarizes our interests in producing wells at December 31, 2012. These figures exclude wells which were capable of producing, but that were not producing, at December 31, 2012:

| Producing Wells – Conventional | Producing Oil Wells | | Producing Gas Wells | | Total Producing Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Alberta | | | | | | |
| Suffield | 769 | 769 | 10,654 | 10,636 | 11,423 | 11,405 |
| Brooks North | 147 | 146 | 7,496 | 7,397 | 7,643 | 7,543 |
| Langevin | 257 | 254 | 4,831 | 4,816 | 5,088 | 5,070 |
| Drumheller | 216 | 211 | 1,594 | 1,537 | 1,810 | 1,748 |
| Wainwright | 453 | 415 | 13 | 3 | 466 | 418 |
| NW Alberta | 7 | 1 | 3 | 2 | 10 | 3 |
| Saskatchewan | | | | | | |
| Weyburn | 687 | 433 | - | - | 687 | 433 |
| Shaunavon / Bakken | 168 | 157 | - | - | 168 | 157 |
| Total | 2,704 | 2,386 | 24,591 | 24,391 | 27,295 | 26,777 |

*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 crude oil field in southeast 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, 2012, approximately 90 percent of the approved CQ flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 20 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. A new contract was executed in 2012 for the purchase of $CO_2$ from Saskatchewan Power Corporation providing an additional source of CQ in the future.

In 2012, we continued developing our medium and light crude oil prospects in the Bakken and Lower Shaunavon zones in Saskatchewan. Our capital investment focused on drilling, completions, and facility work, including the construction and commissioning of batteries in both the Bakkan and Lower Shaunavon areas and supporting infrastructure. Most of the sections of land that we hold in these areas are Crown land.

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** | **2012** | **2011** | **2012** | **2011** | **2012** | **2011** |
| Alberta | | | | | | |
| Suffield | 38 | 45 | - | - | 11,667 | 11,484 |
| Brooks North | 52 | 42 | 2,707 | 1,898 | - | - |
| Langevin | 44 | 68 | 7,551 | 7,172 | - | - |
| Drumheller | 33 | 49 | 3,051 | 1,617 | - | - |
| Wainwright | 57 | 29 | 58 | 67 | 4,348 | 4,173 |
| NW Alberta | - | - | 11 | 9 | - | - |
| Other | 2 | - | - | - | - | - |
| Saskatchewan | | | | | | |
| Weyburn | 6 | 6 | 16,277 | 16,180 | - | - |
| Shaunavon / Bakken | 40 | 81 | 6,416 | 3,581 | - | - |
| Other | 4 | 5 | - | - | - | - |
| Total | 276 | 325 | 36,071 | 30,524 | 16,015 | 15,657 |

*Natural Gas Properties*

We hold 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** | **2012** | **2011** | **2012** | **2011** |
| Suffield | - | - | 167 | 182 |
| Brooks North | - | 65 | 225 | 236 |
| Langevin | - | - | 109 | 118 |
| Drumheller | - | - | 54 | 61 |
| Wainwright | - | - | 3 | - |
| Other | - | - | 3 | 22 |
| Total | - | 65 | 561 | 619 |

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.

In the fourth quarter, the Government of Canada announced that our proposed Shallow Gas Infill Drilling Development Project in the National Wildlife Area ("NWA") of CFB Suffield was not approved. The shallow gas wells we currently have in the NWA are not affected by this decision, and neither are our other oil and natural gas operations in the rest of Suffield.

Natural gas assets are an important component of our financial foundation, generating reliable 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 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 2013, on a 100 percent basis, our refineries have stated processing capacity of approximately 457,000 bbls/d of crude oil (2012 – 452,000 bbls/d), including heavy crude oil processing capability of approximately 235,000 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 2012, the Wood River Refinery had stated processing capacity of 306,000 bbls/d. The start-up of the CORE project was substantially completed in 2011 and the Wood River Refinery demonstrated the benefits of this project in 2012, including an approximate 5 percent increase in clean product yield and Canadian heavy crude oil processing capability averaging in excess of 200,000 bbls/d, when not in turnaround.

For 2013, the Wood River Refinery's stated processing capacity is 311,000 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.



Table of Contents

*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 2012, the Borger Refinery had a stated processing capacity of 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] | **2012** | **2011** |
|---|---|---|
| Crude Oil Capacity (Mbbls/d) | 452 | 452 |
| Crude Oil Runs (Mbbls/d) | 412 | 401 |
| Crude Utilization (%) | 91 | 89 |
| Refined Products (Mbbls/d) | | |
| Gasoline | 216 | 207 |
| Distillates | 138 | 132 |
| Other | 79 | 80 |
| Total | 433 | 419 |

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, 2012.

*Crude Oil Marketing*

We manage the transportation and marketing of crude oil for our upstream operations. Our 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, as well as tankage, terminalling and railcar transportation of both crude oil blend and condensate volumes.

*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 in such markets and by North American regional supply and demand for natural gas.



Table of Contents

## 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 retain 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 coal bed methane ("CBM") reserves annually. 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 contingent and prospective bitumen resources.

The Reserves Committee of our Board of Directors ("Board"), composed of independent Board members, 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 with management and each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to provide a recommendation 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 – Uncertainty of Reserves, Resources 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 12, 2013, with an effective date of December 31, 2012. McDaniel's preparation date of the information is January 10, 2013, and GLJ's preparation date is January 3, 2013.

### 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 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, 2012, 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").



Table of Contents

**Summary of Company Interest Oil and Gas Reserves at December 31, 2012**
**(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 | 172 | 121 | 84 | 917 |
| Developed Non-Producing | 13 | 1 | 9 | 32 |
| Undeveloped | 1,532 | 62 | 22 | 6 |
| **Total Proved Reserves** | 1,717 | 184 | 115 | 955 |
| Probable Reserves | 676 | 105 | 56 | 338 |
| **Total Proved plus Probable Reserves** | 2,393 | 289 | 171 | 1,293 |

**After Royalties**[2]

| Reserves Category | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| **Proved Reserves** | | | | |
| Developed Producing | 134 | 102 | 73 | 930 |
| Developed Non-Producing | 10 | 1 | 7 | 31 |
| Undeveloped | 1,149 | 51 | 18 | 6 |
| **Total Proved Reserves** | 1,293 | 154 | 98 | 967 |
| Probable Reserves | 499 | 79 | 46 | 324 |
| **Total Proved plus Probable Reserves** | 1,792 | 233 | 144 | 1,291 |

**Royalty Interest**

| Reserves Category | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| **Proved Reserves** | | | | |
| Developed Producing | - | 1 | 4 | 43 |
| Developed Non-Producing | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Undeveloped | - | - | - | - |
| **Total Proved Reserves** | - | 1 | 4 | 43 |
| Probable Reserves | - | 1 | 2 | 13 |
| **Total Proved plus Probable Reserves** | - | 2 | 6 | 56 |

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, 2012**
**(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 | 14,927 | 12,313 | 10,485 | 9,155 | 8,149 | 22.62 |
| Developed Non-Producing | 1,048 | 762 | 592 | 480 | 401 | 24.90 |
| Undeveloped | 50,592 | 24,053 | 12,798 | 7,301 | 4,313 | 10.50 |
| **Total Proved Reserves** | 66,567 | 37,128 | 23,875 | 16,936 | 12,863 | 13.99 |
| Probable Reserves | 31,347 | 14,385 | 7,635 | 4,598 | 3,055 | 11.25 |
| **Total Proved plus Probable Reserves** | 97,914 | 51,513 | 31,510 | 21,534 | 15,918 | 13.21 |

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



Table of Contents

**After Income Taxes[1]**

| | Discounted at %/year ($ millions) | | | | |
|---|---|---|---|---|---|
| **Reserves Category** | **0%** | **5%** | **10%** | **15%** | **20%** |
| **Proved Reserves** | | | | | |
| Developed Producing | 11,990 | 9,951 | 8,510 | 7,457 | 6,658 |
| Developed Non-Producing | 788 | 574 | 447 | 364 | 306 |
| Undeveloped | 37,993 | 17,835 | 9,342 | 5,219 | 2,993 |
| **Total Proved Reserves** | 50,771 | 28,360 | 18,299 | 13,040 | 9,957 |
| Probable Reserves | 23,465 | 10,675 | 5,623 | 3,362 | 2,218 |
| **Total Proved plus Probable Reserves** | 74,236 | 39,035 | 23,922 | 16,402 | 12,175 |

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, 2012.

**Total Future Net Revenue (undiscounted) at December 31, 2012**
**(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** | 165,198 | 37,812 | 43,995 | 15,627 | 1,197 | 66,567 | 15,796 | 50,771 |
| **Proved plus Probable Reserves** | 240,555 | 56,238 | 63,315 | 21,709 | 1,379 | 97,914 | 23,678 | 74,236 |

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, 2012**
**(Forecast Prices and Costs)**

| **Reserves Category** | **Production Group** | **Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)** | **Unit Value (Company Interest After Royalties Reserves) ($/BOE)** |
|---|---|---|---|
| **Proved Reserves** | Bitumen | 17,119 | 13.23 |
| | Heavy Oil | 2,697 | 17.55 |
| | Light & Medium Crude Oil and NGLs | 2,538 | 25.91 |
| | Natural Gas | 1,521 | 9.44 |
| | Total | 23,875 | 13.99 |
| **Proved plus Probable Reserves** | Bitumen | 21,771 | 12.15 |
| | Heavy Oil | 4,224 | 18.11 |
| | Light & Medium Crude Oil and NGLs | 3,454 | 23.96 |
| | Natural Gas | 2,061 | 9.58 |
| | Total | 31,510 | 13.21 |

Table of Contents

***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 are rounded to the nearest whole number and tables may not add due to rounding.

**Definitions**

1. **After Royalties** means volumes after deduction of royalties and includes Royalty Interests.
2. **Before Royalties** means volumes before deduction of royalties and excludes Royalty Interests.
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 the working interest owned by us.
6. **Reserves** are estimated remaining quantities anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions.

   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. similar 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.



Table of Contents

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, 2013 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2013. For historical prices realized during 2012, 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) |
| 2013 | 92.50 | 87.50 | 83.10 | 65.60 | 73.90 | 3.35 | 2.0 | 1.00 |
| 2014 | 92.50 | 90.50 | 86.00 | 67.90 | 76.50 | 3.85 | 2.0 | 1.00 |
| 2015 | 93.60 | 92.60 | 88.00 | 69.50 | 78.20 | 4.35 | 2.0 | 1.00 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2016 | 95.50 | 94.50 | 89.80 | 70.90 | 79.90 | 4.70 | 2.0 | 1.00 |
| 2017 | 97.40 | 96.40 | 91.60 | 72.30 | 81.50 | 5.10 | 2.0 | 1.00 |
| 2018 | 99.40 | 98.30 | 93.40 | 73.70 | 83.10 | 5.45 | 2.0 | 1.00 |
| 2019 | 101.40 | 100.30 | 95.30 | 75.20 | 84.80 | 5.55 | 2.0 | 1.00 |
| 2020 | 103.40 | 102.30 | 97.20 | 76.70 | 86.40 | 5.70 | 2.0 | 1.00 |
| 2021 | 105.40 | 104.30 | 99.10 | 78.20 | 88.10 | 5.80 | 2.0 | 1.00 |
| 2022 | 107.60 | 106.50 | 101.20 | 79.90 | 90.00 | 5.90 | 2.0 | 1.00 |
| 2023 | 109.70 | 108.50 | 103.10 | 81.40 | 91.70 | 6.00 | 2.0 | 1.00 |
| There-after | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | 2.0 | 1.00 |

***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) | 2013 | 2014 | 2015 | 2016 | 2017 | Remainder | Total |
|---|---|---|---|---|---|---|---|
| Proved Reserves | 1,680 | 1,315 | 1,122 | 706 | 929 | 9,875 | 15,627 |
| Proved plus Probable Reserves | 1,761 | 1,493 | 1,436 | 912 | 1,067 | 15,040 | 21,709 |

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.



Table of Contents

**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, 2012, 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, 2011** | 1,455 | 175 | 115 | 1,203 |
| Extensions and Improved Recovery | 265 | 17 | 13 | 29 |
| Discoveries | - | - | - | - |
| Technical Revisions | 30 | 6 | (2) | 51 |
| Economic Factors | - | - | - | (58) |
| Acquisitions | - | - | 1 | 1 |
| Dispositions | - | - | - | (59) |
| Production[1] | (33) | (14) | (12) | (212) |
| **December 31, 2012** | 1,717 | 184 | 115 | 955 |

**Probable**

| | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| **December 31, 2011** | 490 | 109 | 51 | 391 |
| Extensions and Improved Recovery | 140 | 11 | 5 | 8 |
| Discoveries | - | - | - | - |
| Technical Revisions | 46 | (15) | - | (30) |
| Economic Factors | - | - | - | (4) |
| Acquisitions | - | - | - | - |
| Dispositions | - | - | - | (27) |
| Production[1] | - | - | - | - |
| **December 31, 2012** | 676 | 105 | 56 | 338 |

**Proved plus Probable**

| | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| **December 31, 2011** | 1,945 | 284 | 166 | 1,594 |
| Extensions and Improved Recovery | 405 | 28 | 18 | 37 |
| Discoveries | - | - | - | - |
| Technical Revisions | 76 | (9) | (2) | 21 |
| Economic Factors | - | - | - | (62) |
| Acquisitions | - | - | 1 | 1 |
| Dispositions | - | - | - | (86) |
| Production[1] | (33) | (14) | (12) | (212) |

| | | | | |
|---|---|---|---|---|
| **December 31, 2012** | 2,393 | 289 | 171 | 1,293 |

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 the FCCL partnership for steam generation, but does not include Royalty Interest Production.



Table of Contents

Proved and proved plus probable bitumen reserves increased by approximately 18 and 23 percent respectively. Regulatory approval and partner sanction of the Narrows Lake project enabled initial booking of proved and proved plus probable reserves. Increases at Christina Lake were primarily a result of plans to increase well density in the development area and improving steam to oil ratio performance. Increases at Foster Creek were primarily due to increased recovery resulting from improved steam to oil ratio performance and more efficient drainage of bitumen in the steam chamber.

Proved heavy oil reserves increased by approximately five percent primarily as a result of expanding polymer flood areas and their successful performance in the Greater Pelican Region. Probable heavy oil reserves decreased by approximately three percent also based on conversion of probable reserves to proved reserves. Proved plus probable reserves increased by approximately two percent.

Proved light and medium oil and NGLs reserves remained unchanged, with production being offset by expanding waterflood and $CO_2$ flood areas and their successful performance at Weyburn. Probable light and medium oil and NGLs reserves increased by approximately 10 percent as a result of continued strong performance. Overall, proved plus probable reserves increased by approximately three percent.

Proved natural gas reserves declined by approximately 21 percent as extensions and technical revisions did not offset production and dispositions. Also included in the decline is a loss of 58 Bcf of gas reserves due to lower gas prices in the forecast causing some gas reserves to become uneconomic to produce. Probable natural gas reserves and proved plus probable reserves declined by approximately 13 percent and 19 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 46 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 | 813 | 734 | 55 | 46 | 45 | 28 | 282 | 35 |
| 2010 | 295 | 1,008 | 5 | 45 | 5 | 27 | 18 | 36 |
| 2011 | 325 | 1,287 | 13 | 55 | 3 | 25 | - | 24 |
| 2012 | 284 | 1,532 | 20 | 61 | 3 | 22 | - | 6 |

**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 | 633 | 467 | 43 | 43 | 26 | 26 | 38 | 38 |
| 2010 | 171 | 506 | - | 37 | 2 | 21 | 16 | 30 |
| 2011 | 113 | 467 | 14 | 47 | 1 | 22 | - | 35 |
| 2012 | 182 | 646 | 9 | 42 | 5 | 24 | - | 16 |



Table of Contents

**Development of Proved Undeveloped Reserves**

*Bitumen*

At the end of 2012, we had proved undeveloped bitumen reserves of 1,532 million barrels Before Royalties, or approximately 89 percent of our total proved bitumen reserves. Of our 676 million barrels of probable bitumen reserves, 646 million barrels, or approximately 96 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 is a minimum of 8 wells per section with 3D seismic, or 16 wells per section with no seismic. 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 44 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 eight years, and $CO_2$ flood advancement continuing many years beyond that. At Pelican Lake, investment in proved undeveloped reserves is projected to continue for 28 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".



Table of Contents

**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 existing SAGD projects that are producing from the McMurray-Wabiskaw formations at Foster Creek and Christina Lake are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at 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 majority of our bitumen resources will be recovered and produced using SAGD or 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 subclassified 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 price assumptions that were used for the 2012 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. The contingent resources disclosed by us are not contingent due to economic factors. Our bitumen contingent resources are located in four general regions: Christina Lake, Foster Creek, Borealis, and the Greater Pelican Region.



Table of Contents

At Christina Lake and Foster Creek we have economic contingent resources located outside the currently approved development project areas. Regulatory approval of development area expansion is necessary to enable the reclassification of these economic contingent resources as reserves. The rate at which we submit applications for development area expansion 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 2012, we received regulatory approval and partner sanction for a development project at Narrows Lake. This enabled reclassification of a significant portion of the contingent resources previously identified as proved and probable reserves.

In the Borealis Region we have submitted an application for a development project of the Telephone Lake property, which, if approved, would enable the reclassification of certain economic contingent resources in the area to reserves. Other areas in the Borealis Region require additional delineation drilling and seismic in order to submit regulatory applications for development projects. Stratigraphic drilling and seismic is continuing in these areas to bring them to project readiness. Currently, sufficient pipeline take-away capacity is also considered a contingency.

Application for development project approval at the Grand Rapids property in the Greater Pelican Lake area was submitted in 2011. Provided all regulatory requirements are met, we anticipate receiving regulatory approval in 2013. Pilot project work is underway to examine optimal development strategies.

**Prospective resources** are those quantities of bitumen petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. 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 range 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 range 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.



Table of Contents

| **Bitumen Economic Contingent and Prospective Resources** | | |
|---|---|---|
| Company Interest Before Royalties, Billions of barrels | **December 31, 2012** | December 31, 2011 |
| Economic Contingent Resources[1] | | |
| Low Estimate | **7.1** | 6.0 |
| Best Estimate | **9.6** | 8.2 |
| High Estimate | **12.8** | 10.8 |
| Prospective Resources[2] | | |
| Low Estimate | **5.0** | 5.7 |
| Best Estimate | **8.5** | 10.0 |
| High Estimate | **14.8** | 17.9 |

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.

Economic bitumen best estimate contingent resources increased 1.4 billion barrels or 17 percent compared to 2011. This increase is primarily due to successful stratigraphic well drilling resulting in the conversion of prospective resources to contingent resources, the recognition of SAGD feasibility in the Wabiskaw formation adjacent to Foster Creek, and the recognition of contingent resources on acquired land near Telephone Lake, and was partially offset by conversion of contingent resources at Narrows Lake to proved and probable reserves.

Bitumen best estimate prospective resources declined 1.5 billion barrels or approximately 15 percent compared to 2011, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic well drilling, and the sterilization of lands resulting from the anticipated provincial adoption of the Lower Athabasca Regional Plan. Refer to “Risk Factors – Alberta’s Land-Use Framework” for more information on the Lower Athabasca Regional Plan.

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, 2011 | 1.945 | 8.2 | 10.0 |
| Transfers between Categories | | | |
| Additions from other resource categories | 0.359 | 1.0 | (1.0) |
| Reductions to other resource categories | - | (0.4) | - |
| Additions and Revisions Net of Transfers | 0.121 | 0.5 | (0.8) |

| | | | |
|---|---|---|---|
| Net Acquisitions and Dispositions | - | 0.3 | 0.3 |
| Production | (0.032) | - | - |
| December 31, 2012 | 2.393 | 9.6 | 8.5 |

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, regulatory approval and partner sanction of the Narrows Lake project and partner approval of phase A resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic well drilling program in the Borealis and the Greater Pelican Regions 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.



Table of Contents

**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, 2012:

**Producing Wells**[1][2]

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Alberta | | | | | | |
| Oil Sands | 797 | 657 | 317 | 304 | 1,114 | 961 |
| Conventional | 1,849 | 1,795 | 24,591 | 24,391 | 26,440 | 26,186 |
| Total Alberta | 2,646 | 2,452 | 24,908 | 24,695 | 27,554 | 27,147 |
| Saskatchewan | 855 | 590 | - | - | 855 | 590 |
| Total | 3,501 | 3,042 | 24,908 | 24,695 | 28,409 | 27,737 |

Notes:
(1) Cenovus also has varying royalty interests in 9,135 natural gas wells and 3,449 crude oil wells which are producing.
(2) Includes wells containing multiple completions as follows: 22,728 gross natural gas wells (22,585 net wells) and 1,324 gross crude oil wells (1,223 net wells).

**Non-Producing Wells**[1]

| | Oil | | Gas | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Alberta | | | | | | |
| Oil Sands | 90 | 83 | 644 | 509 | 734 | 592 |
| Conventional | 749 | 722 | 802 | 777 | 1,551 | 1,499 |
| Total Alberta | 839 | 805 | 1,446 | 1,286 | 2,285 | 2,091 |
| Saskatchewan | 121 | 83 | 28 | 27 | 149 | 110 |
| Total | 960 | 888 | 1,474 | 1,313 | 2,434 | 2,201 |

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.

***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 |
| **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 |
| **2010:** | | | | | | | | | | | |
| Oil Sands | - | - | - | - | - | - | - | - | - | - | - |
| Conventional | 26 | 26 | - | - | 1 | 1 | 27 | 27 | 21 | 48 | 27 |
| Total Canada | 26 | 26 | - | - | 1 | 1 | 27 | 27 | 21 | 48 | 27 |



Table of Contents

**Development Wells Drilled**

| | Oil | | Gas | | Dry & Abandoned | | Total Working Interest | | Royalty | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Gross | Net |
| **2012:** | | | | | | | | | | | |
| Oil Sands | 137 | 107 | - | - | - | - | 137 | 107 | 57 | 194 | 107 |
| Conventional | 273 | 268 | - | - | 1 | 1 | 274 | 269 | 129 | 403 | 269 |
| Total Canada | 410 | 375 | - | - | 1 | 1 | 411 | 376 | 186 | 597 | 376 |
| **2011:** | | | | | | | | | | | |
| Oil Sands | 71 | 51 | 3 | 3 | - | - | 74 | 54 | 87 | 161 | 54 |
| Conventional | 312 | 303 | 66 | 65 | 4 | 4 | 382 | 372 | 156 | 538 | 372 |
| Total Canada | 383 | 354 | 69 | 68 | 4 | 4 | 456 | 426 | 243 | 699 | 426 |
| **2010:** | | | | | | | | | | | |
| Oil Sands | 82 | 47 | - | - | - | - | 82 | 47 | 8 | 90 | 47 |
| Conventional | 160 | 154 | 499 | 495 | - | - | 659 | 649 | 204 | 863 | 649 |
| Total Canada | 242 | 201 | 499 | 495 | - | - | 741 | 696 | 212 | 953 | 696 |

During the year ended December 31, 2012, Oil Sands drilled 473 gross stratigraphic test wells (317 net wells) and Conventional drilled 14 gross stratigraphic test wells (14 net wells).

During the year ended December 31, 2012, Oil Sands drilled 116 gross service wells (112 net wells) and Conventional drilled 22 gross service wells (16 net wells).

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, 2012:

| Landholdings | Developed | | Undeveloped[1] | | Total[2] | |
|---|---|---|---|---|---|---|
| (thousands of acres) | Gross | Net | Gross | Net | Gross | Net |
| Alberta: | | | | | | |
| Oil Sands | | | | | | |
| – Crown[3] | 582 | 487 | 2,256 | 1,792 | 2,838 | 2,279 |
| Conventional | | | | | | |
| – Fee[4] | 1,931 | 1,931 | 442 | 442 | 2,373 | 2,373 |
| – Crown[3] | 1,011 | 910 | 311 | 261 | 1,322 | 1,171 |
| – Freehold[5] | 71 | 60 | 18 | 16 | 89 | 76 |
| Total Alberta | 3,595 | 3,388 | 3,027 | 2,511 | 6,622 | 5,899 |
| Saskatchewan: | | | | | | |
| Conventional | | | | | | |
| – Fee[4] | 78 | 78 | 427 | 427 | 505 | 505 |
| – Crown[3] | 71 | 57 | 291 | 273 | 362 | 330 |
| – Freehold[5] | 14 | 9 | 11 | 7 | 25 | 16 |
| Total Saskatchewan | 163 | 144 | 729 | 707 | 892 | 851 |
| Manitoba: | | | | | | |
| Conventional – Fee[4] | 4 | 4 | 262 | 262 | 266 | 266 |
| Total Manitoba | 4 | 4 | 262 | 262 | 266 | 266 |
| Total | 3,762 | 3,536 | 4,018 | 3,480 | 7,780 | 7,016 |

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.



Table of Contents

***Properties With No Attributed Reserves***

We have approximately 5.1 million gross acres (4.6 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 72,000 net acres that could potentially expire by December 31, 2013, 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.

***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 billion (approximately $989 million, discounted at 10 percent) at December 31, 2012, of which we expect to pay approximately $352 million in the next three financial years. We expect to incur these costs on approximately 35,000 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of our proved reserves, approximately $1.2 billion has been deducted in estimating the future net revenue, which only represents our abandonment obligations for wells within reserves.

***Tax Horizon***

We expect to pay income tax in 2013.

***Costs Incurred***

| ($ millions) | 2012 |
|---|---|
| Acquisitions | |
| – Unproved | 90 |
| – Proved | 24 |
| Total acquisitions | 114 |
| Exploration costs | 424 |
| Development costs | 2,589 |
| Total costs incurred | 3,127 |

***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, 2012.



Table of Contents

***Production Estimates***

The following table summarizes the estimated 2013 average daily volume of Company Interest Before Royalties and Royalty Interest Production reflected in the reserves reports for all properties held on December 31, 2012 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.

| **2013 Estimated Production** Forecast Prices and Costs | Proved | Proved plus Probable |
|---|---|---|
| Bitumen (bbls/d)[1] | 109,400 | 111,550 |
| Light and Medium Crude Oil (bbls/d) | 31,044 | 33,961 |
| Heavy Oil (bbls/d) | 41,541 | 44,035 |
| Natural Gas (MMcf/d) | 467 | 490 |
| Natural Gas Liquids (bbls/d) | 681 | 747 |
| Company Interest Before Royalties Production (BOE/d) | 260,418 | 272,036 |
| Royalty Interest Production (BOE/d) | 6,445 | 6,803 |
| Total Company Interest Before Royalties Plus Royalty Interest Production (BOE/d) | 266,863 | 278,839 |

Note:
(1) Includes Foster Creek production of 58,325 bbls/d for Proved and 59,875 bbls/d for Proved plus Probable.

***Production History***

| **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 |
| Pelican Lake (Heavy Oil) | 22,552 | 23,507 | 23,539 | 22,410 | 20,730 |
| | 112,288 | 124,374 | 119,164 | 102,727 | 102,677 |
| Conventional Liquids | | | | | |
| Heavy Oil | 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 | 33 | 30 | 27 | 33 | 41 |
| Conventional | 535 | 511 | 529 | 536 | 564 |
| 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 | 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.

Table of Contents

| 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 |
| Pelican Lake (Heavy Oil) | 20,424 | 20,558 | 20,363 | 19,427 | 21,360 |
| | 86,957 | 95,134 | 86,752 | 77,680 | 88,188 |
| Conventional Liquids | | | | | |
| Heavy Oil | 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 | 37 | 38 | 39 | 37 | 32 |
| Conventional | 596 | 597 | 597 | 595 | 593 |
| 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 | 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.

| Average Before Royalties + Royalty Interest Daily Production Volumes - 2010 | | | | | |
|---|---|---|---|---|---|
| | Year | Q4 | Q3 | Q2 | Q1 |
| Crude Oil and Natural Gas Liquids (bbls/d) | | | | | |
| Oil Sands | | | | | |
| Foster Creek (Bitumen) | 51,147 | 52,183 | 50,269 | 51,010 | 51,126 |
| Christina Lake (Bitumen) | 7,898 | 8,606 | 7,838 | 7,716 | 7,420 |
| Pelican Lake (Heavy Oil) | 22,966 | 21,738 | 23,259 | 23,319 | 23,565 |
| | 82,011 | 82,527 | 81,366 | 82,045 | 82,111 |
| Conventional Liquids | | | | | |
| Heavy Oil | 16,659 | 16,553 | 16,921 | 16,205 | 16,962 |
| Light and Medium Oil | 29,346 | 29,323 | 28,608 | 29,150 | 30,320 |
| Natural Gas Liquids [1] | 1,171 | 1,190 | 1,172 | 1,166 | 1,156 |
| Total Crude Oil and Natural Gas Liquids | 129,187 | 129,593 | 128,067 | 128,566 | 130,549 |
| Natural Gas (MMcf/d) | | | | | |
| Oil Sands | 43 | 39 | 44 | 46 | 45 |
| Conventional | 694 | 649 | 694 | 705 | 730 |
| Total Natural Gas | 737 | 688 | 738 | 751 | 775 |
| Total (BOE/d) | 252,020 | 244,260 | 251,067 | 253,733 | 259,716 |

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



Table of Contents

***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 – 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 |
| Heavy Oil – Christina Lake ($/bbl) [1][2] | | | | | |
| Price | 47.73 | 43.37 | 52.91 | 44.57 | 52.58 |
| Royalties | 2.72 | 2.32 | 2.61 | 2.90 | 3.37 |
| Transportation and blending | 3.79 | 3.00 | 4.00 | 4.12 | 4.51 |
| Operating | 12.95 | 11.42 | 13.59 | 12.52 | 15.33 |
| Netback | 28.27 | 26.63 | 32.71 | 25.03 | 29.37 |
| Heavy Oil – Pelican Lake ($/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 |
| Heavy Oil - Oil Sands ($/bbl) [1] | | | | | |
| Price | 60.84 | 55.11 | 61.71 | 59.00 | 68.36 |
| Royalties | 5.22 | 3.47 | 7.85 | 2.83 | 6.66 |
| Transportation and blending | 2.74 | 2.63 | 2.52 | 2.87 | 2.99 |
| Operating | 13.33 | 12.41 | 13.29 | 13.61 | 14.18 |
| Netback | 39.55 | 36.60 | 38.05 | 39.69 | 44.53 |
| Heavy Oil - Conventional ($/bbl) [1] | | | | | |
| Price | 70.53 | 64.73 | 68.04 | 67.70 | 80.64 |
| Royalties | 10.06 | 8.68 | 8.81 | 9.36 | 13.06 |
| Transportation and blending | 2.17 | 2.34 | 2.31 | 2.26 | 1.81 |
| Operating | 15.21 | 11.68 | 16.48 | 15.07 | 17.57 |
| Production and mineral taxes | 0.24 | 0.31 | 0.27 | 0.25 | 0.14 |
| Netback | 42.85 | 41.72 | 40.17 | 40.76 | 48.06 |
| Total Heavy Oil ($/bbl) [1] | | | | | |
| Price | 62.05 | 56.22 | 62.45 | 60.13 | 70.08 |
| Royalties | 5.83 | 4.07 | 7.96 | 3.68 | 7.56 |
| Transportation and blending | 2.67 | 2.60 | 2.50 | 2.79 | 2.82 |
| Operating | 13.56 | 12.33 | 13.66 | 13.80 | 14.65 |
| Production and mineral taxes | 0.03 | 0.04 | 0.03 | 0.03 | 0.02 |
| Netback | 39.96 | 37.18 | 38.30 | 39.83 | 45.03 |
| Light and Medium Oil ($/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 |



Table of Contents

| **Per-Unit Results – 2012** | | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Total Liquids ($/bbl) | | | | | |
| Price | 65.79 | 60.13 | 65.35 | 63.92 | 74.28 |
| Royalties | 6.29 | 4.64 | 7.83 | 4.67 | 8.05 |
| Transportation and blending | 2.65 | 2.54 | 2.45 | 2.82 | 2.81 |
| Operating | 13.90 | 12.93 | 14.14 | 13.93 | 14.71 |
| Production and mineral taxes | 0.56 | 0.54 | 0.53 | 0.57 | 0.59 |
| Netback | 42.39 | 39.48 | 40.40 | 41.93 | 48.12 |
| Total Natural Gas ($/Mcf) | | | | | |
| Price | 2.42 | 2.97 | 2.30 | 1.92 | 2.50 |
| Royalties | 0.03 | 0.02 | 0.02 | 0.01 | 0.06 |
| Transportation and blending | 0.10 | 0.10 | 0.08 | 0.08 | 0.13 |
| Operating | 1.10 | 1.29 | 1.08 | 0.98 | 1.08 |
| Production and mineral taxes | 0.01 | (0.01) | 0.02 | 0.02 | 0.02 |
| Netback | 1.18 | 1.57 | 1.10 | 0.83 | 1.21 |
| Total ($/BOE) | | | | | |
| Price | 46.60 | 45.50 | 46.61 | 43.25 | 50.84 |
| Royalties | 4.00 | 3.08 | 5.02 | 2.84 | 5.00 |
| Transportation and blending | 1.88 | 1.86 | 1.74 | 1.90 | 2.00 |
| Operating[3] | 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) The heavy oil price and transportation and blending for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $41.85/bbl; Christina Lake - $45.83/bbl; Pelican Lake - $15.55/bbl; Heavy Oil – Oil Sands - $37.45/bbl; Heavy Oil – Conventional - $13.35/bbl and Total Heavy Oil - $34.44/bbl.
(2) Foster Creek and Christina Lake are bitumen properties.
(3) Operating costs for the year include costs related to long-term incentives of $0.16/BOE.

| **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 |
| Heavy Oil – Pelican Lake ($/bbl) [1] | | | | | |
| Price | 73.07 | 88.67 | 66.76 | 78.26 | 64.66 |
| Royalties | 7.91 | 6.98 | 8.23 | 7.40 | 8.63 |
| Transportation and blending | 4.14 | 12.19 | 1.87 | 2.02 | 2.44 |
| Operating | 14.86 | 16.49 | 14.31 | 13.40 | 15.35 |
| Netback | 46.16 | 53.01 | 42.35 | 55.44 | 38.24 |
| Heavy Oil - Oil Sands ($/bbl) [1] | | | | | |
| Price | 67.99 | 76.39 | 62.93 | 73.02 | 60.35 |
| Royalties | 9.17 | 11.72 | 10.46 | 3.65 | 10.08 |
| Transportation and blending | 3.36 | 4.75 | 2.68 | 2.71 | 3.18 |
| Operating | 13.27 | 13.54 | 13.02 | 13.27 | 13.23 |
| Netback | 42.19 | 46.38 | 36.77 | 53.39 | 33.86 |



Table of Contents

| **Per-Unit Results – 2011** | | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Heavy Oil - Conventional ($/bbl) [1] | | | | | |
| Price | 74.17 | 81.49 | 67.96 | 78.47 | 69.17 |
| Royalties | 10.75 | 11.85 | 11.33 | 10.98 | 9.04 |
| Transportation and blending | 1.27 | 1.34 | 1.80 | 0.91 | 1.05 |
| Operating | 13.77 | 16.34 | 12.40 | 13.66 | 12.78 |
| Production and mineral taxes | 0.32 | 0.34 | 0.17 | 0.22 | 0.51 |
| Netback | 48.06 | 51.62 | 42.26 | 52.70 | 45.79 |
| Total Heavy Oil ($/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[3] | 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) The heavy oil price and transportation and blending for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $41.74/bbl; Christina Lake - $47.07/bbl; Pelican Lake - $16.32/bbl; Heavy Oil – Oil Sands - $36.57/bbl; Heavy Oil – Conventional - $12.73/bbl and Total Heavy Oil - $32.76/bbl.
(2) Foster Creek and Christina Lake are bitumen properties.
(3) Operating costs for the year include costs related to long-term incentives of $0.17/BOE.

| **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 |



Table of Contents

| **Per-Unit Results – 2010** | | | | | |
|---|---|---|---|---|---|
| | **Year** | **Q4** | **Q3** | **Q2** | **Q1** |
| Heavy Oil – Foster Creek ($/bbl)[1][2] | | | | | |
| Price | 58.76 | 58.76 | 58.51 | 54.75 | 63.33 |
| Royalties | 9.08 | 11.41 | 9.56 | 9.38 | 5.76 |
| Transportation and blending | 2.42 | 2.54 | 2.40 | 2.40 | 2.33 |
| Operating | 10.40 | 9.93 | 10.32 | 10.36 | 11.04 |
| Netback | 36.86 | 34.88 | 36.23 | 32.61 | 44.20 |
| Heavy Oil – Christina Lake ($/bbl)[1][2] | | | | | |
| Price | 57.96 | 58.42 | 56.45 | 54.99 | 62.27 |
| Royalties | 2.14 | 2.05 | 2.04 | 2.19 | 2.28 |
| Transportation and blending | 3.54 | 1.54 | 3.69 | 4.52 | 4.47 |
| Operating | 16.47 | 17.16 | 15.88 | 16.59 | 16.26 |
| Netback | 35.81 | 37.67 | 34.84 | 31.69 | 39.26 |
| Heavy Oil – Pelican Lake ($/bbl)[1] | | | | | |
| Price | 62.65 | 61.38 | 58.93 | 62.05 | 68.04 |
| Royalties | 12.96 | 12.76 | 10.62 | 14.06 | 14.34 |
| Transportation and blending | 1.42 | 1.04 | 1.77 | 1.52 | 1.30 |
| Operating | 12.71 | 13.44 | 13.05 | 13.34 | 11.13 |
| Netback | 35.56 | 34.14 | 33.49 | 33.13 | 41.27 |
| Heavy Oil - Oil Sands ($/bbl)[1] | | | | | |
| Price | 59.76 | 59.35 | 58.41 | 56.83 | 64.61 |
| Royalties | 9.53 | 10.79 | 9.30 | 10.03 | 7.94 |
| Transportation and blending | 2.25 | 2.08 | 2.35 | 2.35 | 2.23 |
| Operating | 11.66 | 11.49 | 11.74 | 11.82 | 11.57 |
| Netback | 36.32 | 34.99 | 35.02 | 32.63 | 42.87 |
| Heavy Oil - Conventional ($/bbl)[1] | | | | | |
| Price | 63.18 | 60.45 | 59.40 | 61.35 | 71.16 |
| Royalties | 9.01 | 8.01 | 7.29 | 9.65 | 10.99 |
| Transportation and blending | 0.56 | 0.45 | 0.60 | 0.60 | 0.59 |
| Operating | 12.20 | 13.17 | 11.41 | 13.00 | 11.34 |
| Production and mineral taxes | 0.19 | 0.05 | 0.17 | 0.10 | 0.44 |
| Netback | 41.22 | 38.77 | 39.93 | 38.00 | 47.80 |
| Total Heavy Oil ($/bbl)[1] | | | | | |
| Price | 60.33 | 59.53 | 58.59 | 57.57 | 65.76 |
| Royalties | 9.44 | 10.36 | 8.95 | 9.97 | 8.48 |
| Transportation and blending | 1.97 | 1.83 | 2.04 | 2.06 | 1.94 |
| Operating | 11.75 | 11.75 | 11.68 | 12.02 | 11.53 |
| Production and mineral taxes | 0.03 | 0.01 | 0.03 | 0.02 | 0.08 |
| Netback | 37.14 | 35.58 | 35.89 | 33.50 | 43.73 |
| Light and Medium Oil ($/bbl) | | | | | |
| Price | 71.63 | 72.98 | 68.37 | 66.14 | 78.78 |
| Royalties | 9.30 | 7.69 | 9.32 | 10.17 | 10.05 |
| Transportation and blending | 1.66 | 1.89 | 1.81 | 1.51 | 1.45 |
| Operating | 12.18 | 12.69 | 12.00 | 12.87 | 11.18 |
| Production and mineral taxes | 2.55 | 2.45 | 2.44 | 3.08 | 2.25 |
| Netback | 45.94 | 48.26 | 42.80 | 38.51 | 53.85 |
| Total Crude Oil ($/bbl) | | | | | |
| Price | 62.98 | 62.75 | 60.86 | 59.51 | 68.87 |
| Royalties | 9.41 | 9.72 | 9.03 | 10.01 | 8.85 |
| Transportation and blending | 1.90 | 1.84 | 1.99 | 1.94 | 1.83 |
| Operating | 11.85 | 11.98 | 11.75 | 12.21 | 11.44 |
| Production and mineral taxes | 0.62 | 0.59 | 0.59 | 0.71 | 0.59 |
| Netback | 39.20 | 38.62 | 37.50 | 34.64 | 46.16 |
| Natural Gas Liquids ($/bbl) | | | | | |
| Price | 61.00 | 63.60 | 54.43 | 58.71 | 67.42 |
| Royalties | 1.12 | 0.75 | 1.29 | 1.16 | 1.39 |
| Netback | 59.88 | 62.85 | 53.14 | 57.55 | 66.03 |

Table of Contents

| Per-Unit Results – 2010 | Year | Q4 | Q3 | Q2 | Q1 |
|---|---|---|---|---|---|
| Total Liquids ($/bbl) | | | | | |
| Price | 62.96 | 62.75 | 60.80 | 59.50 | 68.85 |
| Royalties | 9.33 | 9.63 | 8.96 | 9.93 | 8.78 |
| Transportation and blending | 1.88 | 1.82 | 1.97 | 1.94 | 1.83 |
| Operating | 11.74 | 11.82 | 11.64 | 12.10 | 11.34 |
| Production and mineral taxes | 0.62 | 0.59 | 0.59 | 0.71 | 0.59 |
| Netback | 39.39 | 38.89 | 37.64 | 34.82 | 46.31 |
| Total Natural Gas ($/Mcf) | | | | | |
| Price | 4.09 | 3.55 | 3.68 | 3.78 | 5.27 |
| Royalties | 0.07 | (0.04) | 0.08 | 0.07 | 0.14 |
| Transportation and blending | 0.17 | 0.16 | 0.15 | 0.15 | 0.21 |
| Operating | 0.95 | 1.02 | 0.93 | 0.92 | 0.93 |
| Production and mineral taxes | 0.02 | 0.02 | 0.03 | (0.04) | 0.07 |
| Netback | 2.88 | 2.39 | 2.49 | 2.68 | 3.92 |
| Total ($/BOE) | | | | | |
| Price | 44.01 | 42.82 | 41.49 | 41.46 | 50.16 |
| Royalties | 4.93 | 4.90 | 4.73 | 5.26 | 4.81 |
| Transportation and blending | 1.45 | 1.40 | 1.42 | 1.43 | 1.53 |
| Operating[3] | 8.76 | 9.07 | 8.63 | 8.87 | 8.46 |
| Production and mineral taxes | 0.37 | 0.35 | 0.38 | 0.24 | 0.52 |
| Netback | 28.50 | 27.10 | 26.33 | 25.66 | 34.84 |

Notes:
(1) The heavy oil price and transportation and blending for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $35.43/bbl; Christina Lake - $36.66/bbl; Pelican Lake - $14.69/bbl; Heavy Oil – Oil Sands - $29.80/bbl; Heavy Oil - Conventional - $11.08/bbl; Total Heavy Oil - $26.66/bbl.
(2) Foster Creek and Christina Lake are bitumen properties.
(3) Operating costs for the year include costs related to long-term incentives of $0.16/BOE.

| Impact of Realized Financial Hedging - 2010 | Year | Q4 | Q3 | Q2 | Q1 |
|---|---|---|---|---|---|
| Liquids ($/bbl) | (0.36) | (1.29) | 1.01 | (0.40) | (0.78) |
| Natural Gas ($/Mcf) | 1.07 | 1.50 | 1.09 | 1.22 | 0.53 |
| Total ($/BOE) | 2.99 | 3.65 | 3.77 | 3.37 | 1.20 |



Table of Contents

***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 long range business plan as well as generate proceeds to partially fund our capital investment. Early in the first quarter, we completed the sale of non-core Boyer natural gas assets located in Northern Alberta. Production decreased approximately 21 MMcf/d due to the divestiture.

The following table summarizes our net capital investment for 2012 and 2011:

| **Net Capital Investment** ($ millions) | 2012 | 2011 |
|---|---|---|
| Capital Investment | | |
| Upstream | | |
| Foster Creek | 735 | 429 |
| Christina Lake | 579 | 472 |
| Total | 1,314 | 901 |
| Pelican Lake | 518 | 317 |
| Other Oil Sands | 379 | 197 |
| | 2,211 | 1,415 |
| Conventional | 848 | 788 |
| Refining and Marketing | 118 | 393 |
| Corporate | 191 | 127 |
| Capital Investment | 3,368 | 2,723 |
| Acquisitions | 114 | 71 |
| Divestitures | (76) | (173) |
| Net Acquisition and Divestiture Activity | 38 | (102) |
| Net Capital Investment | 3,406 | 2,621 |



Table of Contents

## OTHER INFORMATION

**Competitive Conditions**

All aspects of the oil and gas industry are highly competitive. Refer to “Risk Factors – 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 – 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. 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 its typically low steam to oil ratio.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2012, 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 2013. Refer to “Risk Factors – 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 officially launched on November 30, 2010. It was developed through an award-winning process focused on engagement with employees, external stakeholders and industry experts. The 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 www.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



Table of Contents

limited assurance engagement with Ernst & Young LLP on a select number of quantitative indicators. This report was 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 not 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 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 new Cenovus Operating Management System, which was implemented across the Company 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 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 a new 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.

Our leading CR practices were once again recognized in 2012, with the inclusion of Cenovus to the Dow Jones Sustainability Index (DJSI) North America for the third consecutive year and Cenovus was also named to the DJSI World Index for the first time this year. The Dow Jones Sustainability Indexes track the financial performance of the leading companies worldwide regarding CR performance. Cenovus was also named one of the Top 50 Socially Responsible Corporations in Canada by Maclean’s magazine and Sustainalytics, by Corporate Knights magazine as one of the 2012 Best Corporate Citizens in Canada and the Global 100 Most Sustainable Corporations in the World, announced during the World Economic Forum in Davos.

**Employees**

The following table summarizes our full-time equivalent (“FTE”) employees at December 31, 2012:

| | FTE Employees |
|---|---|
| Oil Sands | 1,271 |
| Conventional | 608 |
| Refining and Marketing | 81 |
| Cenovus-wide | 1,288 |

| | |
|---|---|
| Total | 3,248 |

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

**Foreign Operations**

We, and our reportable segments, are not dependent upon foreign operations. 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 – Foreign Exchange Rates” for information on foreign exchange rate matters affecting Cenovus.



Table of Contents

## 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 Chairman of Enterprise Products Holdings, LLC, the successor general partner of Enterprise Products Partners L.P. From August 2007 to November 2010, Mr. Cunningham served 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 December 2005 to May 2010 Mr. Cunningham served as a director of Enterprise Products GP, LLC, the general partner of Enterprise Product Partners, L.P. From December 2009 to November 2010 he served as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., a publicly traded midstream energy limited partnership. He is currently a director of Agrium Inc., a publicly traded agricultural chemicals company, and a director and Chairman of TETRA Technologies, Inc., a publicly traded energy services and chemicals company. 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. He is also a member of the Association of Professional Engineers and Geoscientists of Alberta. 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. |
| Ian W. Delaney[2,4,5,7] Toronto, Ontario, Canada | 2009 | Mr. Delaney is Chairman of Sherritt International Corporation, a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity and Dacha Strategic Metals Inc., a publicly traded investment company focused on the acquisition, storage and trading of strategic metals. Mr. Delaney was President and Chief Executive Officer of Sherritt International Corporation from January 2009 to December 2011. He is also Chairman of The Westaim Corporation, a publicly traded technology investment company, and Longford Energy Inc., a publicly traded international oil and gas company. |



Table of Contents

| 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 also a Fellow of the Institute of Chartered Accountants of Alberta, and participates on several CAPP committees, including Oil Sands CEO Council, a member of the Canadian Institute of Chartered Accountants (CICA), a member of the Canadian Council of Chief Executives, Chair of the Calgary Police Foundation and member of the Global Commerce Strategy Advisory Panel. He previously served as Chairman of CICA’s Risk Oversight and Governance Board and on the board of CAPP. |
| Michael A. Grandin[2,5,9] Calgary, Alberta, Canada | 2009 (Chair) | Mr. Grandin is the Chair of our Board. He is also director of BNS Split Corp. II, an investment fund, 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 Corporation. 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), 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. |
| 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 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. |



Table of Contents

| Name and Residence | Director Since[1] | Principal Occupation During the Past Five Years |
|---|---|---|
| Wayne G. Thomson[2,5,6,7] Calgary, Alberta, Canada | 2009 | Mr. Thomson is a director & Chief Executive Officer of Iskander Energy Corp., a private international oil and gas company. He is Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves. He is also a director of Virgin Resources Limited, a private international oil and gas company, and TVI Pacific Inc., a publicly traded international resource company. 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.



Table of Contents

**Executive Officers**

The following individuals served as executive officers of Cenovus as at December 31, 2012.

| Name and Residence | Office Held and Principal Occupation During the Past Five Years |
|---|---|
| Brian C. Ferguson Calgary, Alberta, Canada | President & Chief Executive Officer<br><br>Mr. Ferguson's biographical information is included under "Directors". |
| Ivor M. Ruste Calgary, Alberta, Canada | Executive Vice-President & Chief Financial Officer<br><br>Mr. Ruste became Executive Vice-President & Chief Financial Officer on November 30, 2009. Between 2008 and November 2009, Mr. Ruste held the following positions with Encana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer effective May 2009; and Executive Vice-President & Chief Risk Officer effective January 2008. |
| John K. Brannan Calgary, Alberta, Canada | Executive Vice-President & Chief Operating Officer<br><br>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). Between 2008 and November 2009, Mr. Brannan held the following position with Encana: Executive Vice-President (President, Integrated Oil Division) effective January 2007. |
| Harbir S. Chhina Calgary, Alberta, Canada | Executive Vice-President, Oil Sands<br><br>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. Between 2008 and November 2009, Mr. Chhina held the following position with Encana: Vice-President, Upstream Operations, Integrated Oil Sands Division effective January 2007. |

| | |
|---|---|
| Kerry D. Dyte<br>Calgary, Alberta,<br>Canada | Executive Vice-President, General Counsel & Corporate Secretary<br><br>Mr. Dyte became Executive Vice-President, General Counsel & Corporate Secretary on November 30, 2009. Between 2008 and November 2009, Mr. Dyte held the following position with Encana: from January 2007 to November 2009, Vice-President, General Counsel & Corporate Secretary. |
| Judy A. Fairburn<br>Calgary, Alberta,<br>Canada | Executive Vice-President, Environment & Strategic Planning<br><br>Ms. Fairburn became Executive Vice-President, Environment & Strategic Planning on November 30, 2009 and continued in that role until January 31, 2013. Between 2008 and November 2009, Ms. Fairburn held the following positions with Encana: Vice-President, Environment & Corporate Responsibility effective May 2009; Vice-President, Environment & Strategic Planning effective December 2008; and Vice-President, Downstream Operations effective January 2007. |
| Sheila M. McIntosh<br>Calgary, Alberta,<br>Canada | Executive Vice-President, Communications & Stakeholder Relations<br><br>Ms. McIntosh became Executive Vice-President, Communications & Stakeholder Relations on November 30, 2009. Between 2008 and November 2009, Ms. McIntosh held the following position with Encana: Executive Vice-President, Corporate Communications effective January 2007. |



Table of Contents

| Name and Residence | Office Held and Principal Occupation During the Past Five Years |
|---|---|
| Donald T. Swystun<br>Calgary, Alberta,<br>Canada | Executive Vice-President, Refining, Marketing, Transportation & Development<br><br>Mr. Swystun became Executive Vice-President, Refining, Marketing, Transportation & Development on December 1, 2010. From November 2009 to November 2010, Mr. Swystun was our Executive Vice-President (President, Canadian Plains Division). Between 2008 and November 2009, Mr. Swystun held the following position with Encana: Executive Vice-President (President, Canadian Plains Division) effective January 2007. |
| Hayward J. Walls<br>Calgary, Alberta,<br>Canada | Executive Vice-President, Organization & Workplace Development<br><br>Mr. Walls became Executive Vice-President, Organization & Workplace Development on November 30, 2009. Between 2008 and November 2009, Mr. Walls held the following position with Encana: Executive Vice-President, Corporate Services effective January 2006. |

As of December 31, 2012, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,208,431 Common Shares or approximately 0.16 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, other than as described below, none of our current directors or executive officers is, as at the date of this AIF, or has been, within 10 years before 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, at the date of this AIF, or has been within 10 years before 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 its own 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 before 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.

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



Table of Contents

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 (United States). 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 relevant education and experience of each of the members of the Audit Committee 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



Table of Contents

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, 2012 and 2011:

| ($ thousands) | 2012 | 2011 |
|---|---|---|
| Audit Fees[(1)] | 2,707 | 2,682 |
| Audit-Related Fees[(2)] | 8 | 8 |
| Tax Fees[(3)] | 414 | 714 |
| All Other Fees[(4)] | 124 | 66 |
| Total | 3,253 | 3,470 |

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 review of reserves and Director and Executive Compensation disclosures.
(3) Tax Fees consist of fees for tax compliance services, tax advice and tax planning. The services provided in this category primarily included support of SR&ED claims for Cenovus Energy Inc. and FCCL Partnership.
(4) The services provided in this category included the payment of maintenance fees associated with a research tool that grants access to a comprehensive library of financial reporting and assurance literature.



Table of Contents

## 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, 2012, there were approximately 755.8 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 confirmed 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



Table of Contents

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 of December 31, 2012:

| | 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, at any time, and 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



Table of Contents

categories. Cenovus may be vulnerable to future events but qualifying negative factors are considered manageable.

## 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 $0.242 per share payable on March 28, 2013 to holders of Common Shares of record as of March 15, 2013. Readers should also refer to risk factors "Risk Factors - 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 |
|---|---|---|---|---|---|
| 2012 | 0.88 | 0.22 | 0.22 | 0.22 | 0.22 |
| 2011 | 0.80 | 0.20 | 0.20 | 0.20 | 0.20 |
| 2010 | 0.80 | 0.20 | 0.20 | 0.20 | 0.20 |

## 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 2012:

| 2012 | 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 | 36.98 | 33.24 | 36.59 | 34,315 | 37.06 | 32.45 | 36.44 | 20,558 |
| February | 39.64 | 36.51 | 38.46 | 34,949 | 39.81 | 36.50 | 38.80 | 22,677 |
| March | 39.11 | 34.56 | 35.90 | 41,838 | 39.65 | 34.55 | 35.94 | 23,081 |
| April | 36.00 | 33.06 | 35.85 | 37,179 | 36.40 | 32.93 | 36.25 | 23,350 |
| May | 36.68 | 31.36 | 32.55 | 34,456 | 37.26 | 30.60 | 31.43 | 29,840 |
| June | 33.73 | 30.09 | 32.37 | 40,829 | 33.15 | 28.83 | 31.80 | 26,901 |
| July | 34.55 | 30.49 | 30.65 | 36,199 | 33.91 | 30.40 | 30.51 | 28,946 |
| August | 33.73 | 30.37 | 32.30 | 25,290 | 34.23 | 30.20 | 32.70 | 16,332 |
| September | 36.25 | 31.84 | 34.31 | 29,407 | 37.31 | 31.56 | 34.85 | 16,469 |
| October | 35.63 | 32.85 | 35.23 | 27,455 | 36.11 | 33.24 | 35.31 | 17,926 |
| November | 35.69 | 31.82 | 33.36 | 25,626 | 35.90 | 31.74 | 33.35 | 19,166 |
| December | 34.15 | 32.12 | 33.29 | 31,681 | 34.60 | 32.54 | 33.54 | 19,892 |

## 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 program and practice, an annual review of our principal and emerging risks, an analysis of the severity and likelihood of each principal risk, an evaluation of the effectiveness of our current mitigation procedures and the further mitigation or treatment of risks. In addition, we continuously monitor our risk profile as well as industry best practices.



Table of Contents

**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. Some of these risks have intensified in recent years due to difficult market conditions caused by global economic challenges. These risks have impacted and may continue to impact our customers and suppliers and may alter our spending and operating plans. There may be unexpected business impacts due to general market uncertainty. Continued economic uncertainty means that oil and gas producers, including Cenovus, may face the risk of restricted access to capital and increased borrowing costs.

***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: global economic conditions; the actions of the Organization of Petroleum Exporting Countries; government regulation; political stability; the supply of and demand for crude oil; 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: market competitiveness; weather; industry planned and unplanned refinery maintenance; and global supply and demand for refined products. 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 repay our borrowings. 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



Table of Contents

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 or 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 fund our capital, operating and financing commitments. 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.

Cenovus currently has US$4.75 billion in debt securities outstanding. We have no debt maturities until a tranche in the amount of US$800 million matures on September 15, 2014. We have a $3.0 billion committed credit facility, with a maturity of November 30, 2016, of which the entire amount was available at December 31, 2012, 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 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, or if repayment is required before maturity, our ability to make capital investments, continue our business plan 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. 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.



Table of Contents

***Interest Rates***

We may be exposed to fluctuations in interest rates as a result of the use of floating rate debt, floating rate credit facilities and commercial paper. An increase in interest rates could increase our net interest expense and negatively impact our financial results. Additionally, we are exposed to changes in 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 refinance our debt obligations on similar terms and at similar interest rates, 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; 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 or injury to life, result in loss of or damage to equipment, property, information technology systems and related data and control systems and the environment 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, 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. 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. In addition, 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



Table of Contents

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 or transportation failures; 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 with respect to royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, all of which may vary considerably from actual results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. 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



Table of Contents

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 and 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 and other fuels 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



Table of Contents

may affect our business. 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 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. Recent changes to the Alberta royalty and mineral tax regime, as well as the potential for changes in the royalty and mineral tax regimes applicable in other provinces, have created uncertainty relating to the ability of producers 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 the crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other 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 regulation imposes, 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. It also imposes 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. 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 and various provincial and United States federal and state governments have announced intentions to regulate GHG emissions and other air pollutants (collectively, "regulations"). These regulations are in various phases of review, discussion or implementation in the U.S. and Canada. Uncertainties exist relating to the timing and effects of these proposed 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 in any jurisdiction in which we operate or conduct business, may include, but are not limited to: increased compliance costs; permitting delays and/or 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 by our projects 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 by 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.





***Carbon Fuel Standards***

Existing and proposed environmental legislation in certain U.S. states and Canadian provinces regulating carbon fuel standards could result in increased costs and/or reduced revenue. The potential regulation may negatively affect the marketing of our bitumen, crude oil or refined products, or require us to purchase emissions credits in order to affect sales in such jurisdictions.

***Alberta's Land-Use Framework***

Alberta's Land-Use Framework is being 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.

On August 22, 2012, the Government of Alberta approved its Lower Athabasca Regional Plan ("LARP"), which was issued under the ALSA. The LARP came into effect on September 1, 2012.

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. As a result of LARP, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted, limiting the pace of development due to environmental limits and thresholds. It is not expected that the areas identified will have a direct impact on our strategic plan, our current operations at Foster Creek and Christina Lake, or any of our filed applications.

***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).

***Alberta's Regulatory Enhancement Project***

As part of the Government of Alberta's competitiveness review, a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project") was initiated in March 2010. The Project's goal is to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. The Project involved engagement with a broad

range of stakeholders, including industry, and led to a recommendation to the Minister of Energy, in the fourth quarter of 2010, for adoption of a coordinated policy framework and an integrated regulatory system for the upstream oil and gas sector. The Government of Alberta has accepted the Project team's recommendations and is proceeding to implement those recommendations.

On October 24, 2012, the Government of Alberta introduced, in the Alberta Legislature, Bill 2, the*Responsible Energy Development Act*, which creates a single provincial regulator for upstream energy resource activities involving oil, gas, oil sands and coal. The Government of Alberta's goal with the proposed legislation is to streamline and reduce costs of regulations of upstream energy resource activities.

Under the proposed legislation, the single regulator will assume the regulatory functions of the Energy Resources Conservation Board and Alberta Environment and Sustainable Resource Development, with respect to oil, gas, oil sands and coal development. The arm's-length agency will be governed by a board of directors and have a chief executive officer. It is expected to be operational by June 2013.

We understand the Government of Alberta's goals are expected to be achieved as a result of the proposed legislation however, if such legislation is approved, during the transition period to a new single regulator our regulatory applications and any proceedings with the respective regulators may be delayed or interrupted which may negatively impact our development plans.



Table of Contents

***Alberta Environment and Sustainable Resource Development WaterLicences***

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.

**Reputation Risks**

We rely on our reputation to build and maintain positive relationships with our stakeholders, to recruit and maintain 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 the fact that much of the focus is on bitumen mining operations and not in-situ production, public concerns about GHG emissions and water and land use practices in oil sands developments 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 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 Management's Discussion and Analysis for the year ended December 31, 2012, available at www.sedar.com, www.sec.gov and www.cenovus.com.



Table of Contents

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are 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.

There have not been any 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, 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, 2012, 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 auditors’ report dated February 13, 2013 in respect of our Consolidated Financial Statements which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011 and the consolidated statements of earnings and comprehensive income, shareholders’ equity and cash flows for the years ended December 31, 2012, 2011, and 2010 and Cenovus’s internal control over financial reporting as at December 31, 2012. 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.



Table of Contents

## TRANSFER AGENTS AND REGISTRARS

In Canada:
Computershare Investor Services Inc.
9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
Canada

In the United States:
Computershare Trust Company NA
Suite 750, 350 Indiana Street
Golden, CO 80501
U.S.A.

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, 2012. 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 governance practices, is included in our management proxy circular for our most recent annual meeting of shareholders.

Disclosure regarding the contribution of each business segment to revenues and earnings can be found in our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2012, which disclosure is incorporated by reference into this AIF.

The corporate governance rules of the NYSE are generally not applicable to non-U.S. companies; however we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. companies listed on the NYSE. Except as summarized on our website at www.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, 2012 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 (“IFRS”), which are also generally accepted accounting principles for publicly accountable enterprises in Canada.



Table of Contents

## ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

TM Trademark of Cenovus Energy Inc.

In this AIF, certain natural gas volumes have been converted to BOE or MBOE on the basis of six Mcf to one bbl. BOE and MBOE 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.



Table of Contents

## 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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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, 2012.

| 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 10, 2013 | Canada | 29,356 |
| GLJ Petroleum Consultants Ltd. | Cenovus Energy Inc. Corporate Evaluation January 3, 2013 | Canada | 2,154 |
| | | | 31,510 |

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:

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

/s/ Keith Braaten
Keith Braaten
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 12, 2013



Table of Contents

## 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, 2012, 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.

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer

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

/s/ Michael A. Grandin
Michael A. Grandin
Director and Chair of the Board

/s/ Wayne G. Thomson
Wayne G. Thomson
Director and Chair of the Reserves Committee

February 13, 2013



---

Table of Contents

## 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:



Table of Contents

- 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.



Table of Contents

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.



---

Table of Contents

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.



Table of Contents

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.



Table of Contents

**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;



Table of Contents

    (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.



Table of Contents

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.



Table of Contents

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.



Table of Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2012

**WHERE TO FIND:**


| | |
|---|---|
| OVERVIEW OF CENOVUS | 2 |
| 2012 OPERATING AND FINANCIAL HIGHLIGHTS | 4 |
| OPERATING RESULTS | 6 |
| COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS | 7 |
| FINANCIAL RESULTS | 9 |
| REPORTABLE SEGMENTS | 15 |
| OIL SANDS | 15 |
| CONVENTIONAL | 19 |
| REFINING AND MARKETING | 22 |
| CORPORATE AND ELIMINATIONS | 23 |
| QUARTERLY RESULTS | 26 |
| OIL AND GAS RESERVES AND RESOURCES | 27 |
| LIQUIDITY AND CAPITAL RESOURCES | 30 |
| RISK MANAGEMENT | 34 |
| CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES | 39 |
| CONTROL ENVIRONMENT | 43 |
| TRANSPARENCY AND CORPORATE RESPONSIBILITY | 43 |
| OUTLOOK | 44 |
| ADVISORY | 45 |
| ABBREVIATIONS | 47 |


*This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "Cenovus", or the "Company") dated February 13, 2013, should be read in conjunction with our December 31, 2012 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at* www.cenovus.com.

**Basis of Presentation**

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

**Non-GAAP Measures**

*Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as operating cash flow, cash flow, operating earnings, free cash flow, debt, capitalization and adjusted EBITDA, and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Operating Results, Financial Results and Liquidity and Capital Resources sections of this MD&A.*

Table of Contents

## OVERVIEW OF CENOVUS

We are a Canadian, integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2012, we had a market capitalization of approximately $25 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our total 2012 average crude oil and NGLs production was in excess of 165,000 barrels per day, our average natural gas production was in excess of 590 MMcf per day and our refinery operations produced approximately 433,000 barrels per day of refined product. Our reportable segments are: Oil Sands, Conventional, Refining and Marketing and Corporate and Eliminations.

### Our Strategy

Our strategy is to create long-term value for our shareholders through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

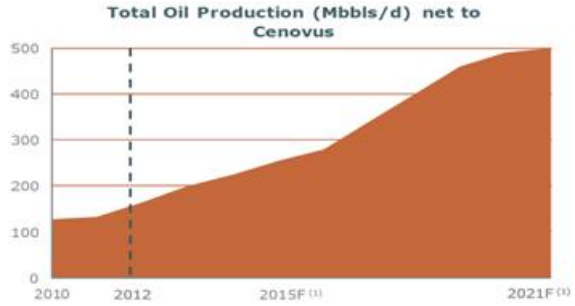
Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

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

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

#### *Oil Production*

We plan to increase our net oil sands bitumen production to 400,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 500,000 barrels per day by the end of 2021. We are focusing on the development of our substantial crude oil resources predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows Lake and our tight oil opportunities in Alberta and Saskatchewan. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 350-450 gross stratigraphic test wells each year for the next five years.




*(1) Expected gross production capacity.*

### Oil Sands

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

| | Ownership Interest (percent) | 2012 Net Production Volumes (bbls/d) | Current Expected Gross Production Capacity (bbls/d) |
|---|---|---|---|
| **Existing Projects** | | | |
| Foster Creek | 50 | 57,833 | 310,000 |
| Christina Lake | 50 | 31,903 | 300,000 |
| Narrows Lake | 50 | - | 130,000 |
| **Emerging Plays** | | | |
| Grand Rapids | 100 | - | 180,000 |
| Telephone Lake | 100 | - | 300,000 |

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca Region of northeast Alberta. In addition to current production, expansion work is underway at phases F, G and H at Foster Creek with added production capacity expected in 2014. In the third quarter of 2013, Christina Lake is anticipating production from phase E. For our Narrows Lake property, we received regulatory approval in May 2012 for phases



Table of Contents

A, B and C, and final partner approval in December 2012 for phase A. Site preparation is underway and we anticipate first production in 2017.

Two of our emerging projects are Grand Rapids and Telephone Lake. At our Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and Environmental Impact Assessment ("EIA") for a commercial SAGD operation. We anticipate regulatory approval in the fourth quarter of 2013. Our Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA due to an increase in the project development area which we anticipate receiving regulatory approval in 2014.

Also located within the Athabasca Region is our wholly owned Pelican Lake property. Pelican Lake produces heavy oil using polymer flood technology and has expected production capacity of 55,000 barrels per day.

### Conventional

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

| For the Year Ended December 31, 2012 ($ millions) | Crude Oil and NGLs | Natural Gas |
|---|---|---|
| Operating Cash Flow | 962 | 482 |
| Capital Investment | 805 | 43 |
| **Operating Cash Flow in Excess of Related Capital Investment** | 157 | 439 |

We have established conventional crude oil and natural gas producing assets and developing tight oil assets. In Saskatchewan, we also inject carbon dioxide to enhance

oil recovery at our Weyburn operations.

### *Refining and Marketing*

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

| | Ownership Interest (percent) | 2012 Nameplate Capacity (Mbbls/d) |
|---|---|---|
| Wood River [1] | 50 | 306 |
| Borger | 50 | 146 |

*(1) Effective January 1, 2013, Wood River has a nameplate capacity of 311,000 barrels per day.*

Our refining operations allow us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel to mitigate volatility associated with North American commodity price movements. This segment also includes the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

| ($ millions) | 2012 |
|---|---|
| Operating Cash Flow | 1,267 |
| Capital Investment | 118 |
| **Operating Cash Flow in Excess of Related Capital Investment** | 1,149 |

### *Technology and Environment*

Technology development plays a key role in improving the amount of bitumen we can access and extract from the ground, potentially reducing costs and building on our history of excellent project execution. The Cenovus culture fosters new ideas and new approaches and has a track record of developing innovative solutions that unlock previously inaccessible resources. Environmental considerations are embedded into our business with the objective of reducing our environmental impact. We are advancing technologies with the goal of reducing the amount of water, natural gas and electricity consumed in our operations and minimizing surface land disturbance.

### *Dividend*

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return.

### *Net Asset Value*

We measure our success in a number of ways with a key measure being growth in net asset value. Our operational and financial performance in 2012 and consistent production growth has increased our net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.



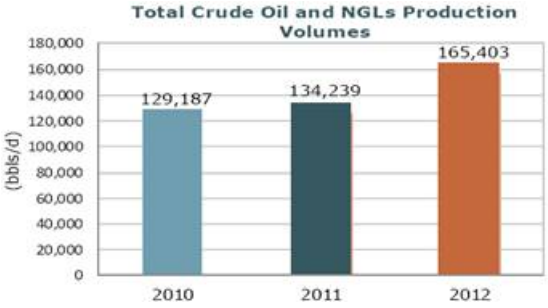
Table of Contents

## 2012 OPERATING AND FINANCIAL HIGHLIGHTS

In 2012, we delivered solid performance and achieved or exceeded the milestones we set out for the year. We completed our planned capital programs, met or exceeded our production targets and increased our net asset value.

### Operational Results

Crude oil production from our Oil Sands segment averaged 112,288 barrels per day, an increase of 29 percent, primarily due to increased production at Christina Lake and Foster Creek. Christina Lake phase D, our 9th SAGD expansion phase to come online, came on production ahead of schedule in late July, 2012 and below budgeted cost. This was the result of effective use of our Nisku module yard, faster ramp-up of production from improved start-up techniques and production commencing in a higher quality area of the reservoir. Christina Lake set a new single day gross production high of almost 94,000 barrels per day in 2012 and has exceeded gross nameplate capacity of 98,000 barrels per day in early 2013.




Within our Conventional segment, crude oil and NGLs production averaged 53,115 barrels per day, an increase of 12 percent, as a result of our successful drilling programs. Alberta production increased 10 percent to an average of 30,357 barrels per day and Saskatchewan production increased 15 percent to an average of 22,758 barrels per day.

Our proved bitumen reserves increased 18 percent to over 1.7 billion barrels and our economic bitumen best estimate contingent resources increased 17 percent to 9.6 billion barrels, demonstrating our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Our refining operations produced approximately 433,000 barrels per day of refined products, an increase of about 14,000 barrels per day. The increase resulted from greater heavy crude oil processing capability as a result of a full year of operations from the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery which was completed in the fourth quarter of 2011. Refining operations processed an average of 412,000 (2011 – 401,000) barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, despite planned turnarounds at both refineries in the fourth quarter of 2012.

Other significant operational results in 2012, as compared to 2011, include:

- Christina Lake production averaging 31,903 barrels per day, more than doubling, due to the start-up of phases C and D in the third quarters of 2011 and 2012, respectively;
- Foster Creek production averaging 57,833 barrels per day, an increase of five percent due to plant optimization;
- Pelican Lake production averaging 22,552 barrels per day, an increase of 10 percent as a result of our infill drilling and polymer flood programs;
- Natural gas production declining nine percent to an average of 594 MMcf per day, primarily due to expected natural declines and the divestiture of a non-core property early in the first quarter of 2012;
- Receiving regulatory approval for phases A, B and C, and partner approval for phase A of our Narrows Lake project;
- Completing planned refinery turnarounds at both Borger and Wood River; and
- Accessing new markets for our crude oil through pipeline to the west coast and rail to the east coast and U.S.

### Financial Results

Throughout 2012, our financial results benefited from strong crude oil production and continued high refining margins, despite declines in crude oil, NGLs and natural gas

prices. Total operating cash flow reached $4.4 billion (an increase of 15 percent) and cash flow was $3.6 billion (an increase of 11 percent). Operating earnings were $866 million (a decrease of 30 percent) primarily due to a goodwill impairment in the fourth quarter related to our Suffield area within our Conventional segment. Net earnings declined 33 percent to $993 million, primarily resulting from non-cash items related to decreases in gains recorded on unrealized risk management activities and divestitures. We completed a US$1.25 billion public offering of senior unsecured notes in August and paid annual dividends of $0.88 per share (2011 – $0.80 per share).



Table of Contents

Other financial highlights for 2012, as compared to 2011, include:

***Revenues***

Revenues of $16,842 million, increasing $1,146 million or seven percent as a result of:
- Crude oil and NGLs sales volumes increasing 25 percent;
- Refining and Marketing revenues rising $731 million due primarily to higher refinery output and refined product prices; and
- A decrease in crude oil and NGLs royalties by 20 percent primarily due to an increase in capital investment.

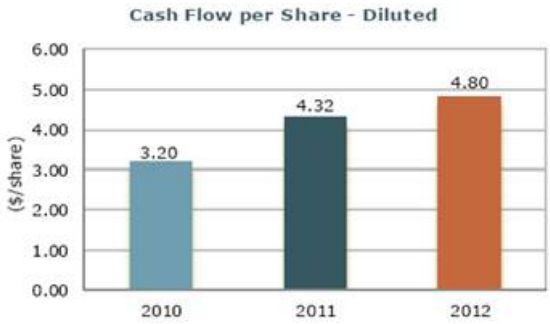
Partially offsetting these increases in revenues were:
- Our crude oil and NGLs average sales prices (excluding financial hedging) decreasing 10 percent; and
- Natural gas revenues decreasing $344 million due to declining production and lower average sales prices.

***Operating Cash Flow***

Operating cash flow of $4,436 million, increasing $574 million or 15 percent due to:
- Upstream operating cash flow of $3,169 million, an improvement of $288 million, due to higher crude oil and NGLs volumes, partially offset by lower realized crude oil and natural gas prices and lower natural gas volumes; and
- Operating cash flow of $1,267 million from our Refining and Marketing segment increasing $286 million on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

***Cash Flow***

Cash flow of $3,643 million, increasing $367 million or 11 percent, primarily due to higher operating cash flow, partially offset by:
- An increase in current income tax, excluding tax on divestitures, of $168 million mainly due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and improved operating cash flow from our Canadian operations; and
- An increase in our general and administrative expenses due to higher staffing and office support costs in-line with our growth.




***Operating Earnings***

Operating earnings of $866 million, decreasing $373 million or 30 percent primarily due to the following non-cash items:
- Goodwill impairment of $393 million in our Conventional segment at Suffield, resulting primarily from declining future cash flows due to lower natural gas and crude oil prices and increased operating costs. We have also had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the goodwill which arose in 2002, exceeded its fair value;
- Increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates; and
- Increased exploration expense.

Higher cash flow partially offset the decreases in operating earnings as discussed above.

***Net Earnings***

Net earnings of $993 million, decreasing $485 million or 33 percent, as decreases in operating earnings discussed above, decreases in unrealized risk management gains, after tax and a gain on divestiture in 2011 were partially offset by higher unrealized foreign exchange gains.

***Capital Investment***

Capital investment of $3,368 million, increasing $645 million or 24 percent primarily due to expansion of our Oil Sands operations and the development of tight oil opportunities in our Conventional segment, partially offset by reduced capital spending in Refining and Marketing with the completion of the CORE project in 2011.



Table of Contents

## OPERATING RESULTS

### Crude Oil Production Volumes

| (barrels per day) | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| **Oil Sands** | | | | | |
| Foster Creek | 57,833 | 5% | 54,868 | 7% | 51,147 |
| Christina Lake | 31,903 | 173% | 11,665 | 48% | 7,898 |
| Pelican Lake | 22,552 | 10% | 20,424 | -11% | 22,966 |
| **Conventional** | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Heavy Oil | 16,015 | 2% | 15,657 | -6% | 16,659 |
| Light & Medium Oil | 36,071 | 18% | 30,524 | 4% | 29,346 |
| NGLs [1] | 1,029 | -7% | 1,101 | -6% | 1,171 |
| | 165,403 | 23% | 134,239 | 4% | 129,187 |

*(1) NGLs include condensate volumes.*

In 2012, our crude oil and NGLs production increased 23 percent due to the start-up of Christina Lake phases C and D in the third quarters of 2011 and 2012 respectively, improved well performance and plant optimization at Foster Creek and rising production at Pelican Lake from our infill drilling and polymer flood program. Our successful drilling program in Alberta and drilling, completions and facilities work in Saskatchewan, also contributed to higher production.

### Natural Gas Production Volumes

| (MMcf per day) | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| Conventional | 561 | -9% | 619 | -11% | 694 |
| Oil Sands | 33 | -11% | 37 | -14% | 43 |
| | 594 | -9% | 656 | -11% | 737 |

In 2012, our natural gas production declined nine percent. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years. Declines were also a result of the divestiture of our Boyer property in early 2012, partially offset by the absence of weather related production issues that were encountered in 2011. Excluding the impact of the first quarter divestiture, our natural gas production would have decreased six percent.

### Operating Netbacks

| | 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| | Crude Oil & NGLs ($/bbl) | Natural Gas ($/Mcf) | Crude Oil & NGLs ($/bbl) | Natural Gas ($/Mcf) | Crude Oil & NGLs ($/bbl) | Natural Gas ($/Mcf) |
| Price [1] | 65.79 | 2.42 | 72.84 | 3.65 | 62.96 | 4.09 |
| Royalties | 6.29 | 0.03 | 9.84 | 0.06 | 9.33 | 0.07 |
| Transportation and Blending [1] | 2.65 | 0.10 | 2.76 | 0.15 | 1.88 | 0.17 |
| Operating Expenses | 13.90 | 1.10 | 13.47 | 1.10 | 11.74 | 0.95 |
| Production and Mineral Taxes | 0.56 | 0.01 | 0.56 | 0.04 | 0.62 | 0.02 |
| **Netback Excluding Realized Risk Management** | 42.39 | 1.18 | 46.21 | 2.30 | 39.39 | 2.88 |
| Realized Risk Management Gains (Losses) | 1.39 | 1.14 | (2.79) | 0.87 | (0.36) | 1.07 |
| **Netback Including Realized Risk Management** | 43.78 | 2.32 | 43.42 | 3.17 | 39.03 | 3.95 |

*(1) Heavy crude oil is mixed with purchased condensate. The crude oil and NGLs price and transportation and blending costs exclude the impact of condensate purchases of $26.72 per barrel (2011 – $24.91 per barrel; 2010 – $20.36 per barrel).*

In 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $3.82 per barrel from 2011. Sales prices were lower in 2012, consistent with lower benchmark prices and decreased sales prices for Christina Lake due to the Christina Dilbit Blend ("CDB") differential to Western Canadian Select ("WCS"). In addition, higher operating costs as a result of workover activities, workforce and repairs and maintenance costs also decreased our average netback. This decrease was offset by a reduction in royalties primarily due to increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.12 per Mcf in 2012 predominantly as a result of lower sales prices as compared to 2011.



Table of Contents

### Refining [1]

| | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| Crude Oil Runs (Mbbls/d) | 412 | 3% | 401 | 4% | 386 |
| Refined Product (Mbbls/d) | 433 | 3% | 419 | 3% | 405 |
| Crude Utilization (percent) | 91 | 2% | 89 | 3% | 86 |

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

Crude oil runs and refined product improved three percent as a result of a full year of operations after completion of the CORE project at the Wood River Refinery. Improvements were partially offset by longer than expected planned turnarounds at both refineries in the fourth quarter of 2012.

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

## COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

### Selected Benchmark Prices and Exchange Rates [1]

| | Q4 2012 | 2012 | 2011 | 2010 |
|---|---|---|---|---|
| **Crude Oil Prices** (US$/bbl) | | | | |
| Brent Futures | | | | |
| Average | 110.13 | 111.68 | 110.91 | 80.34 |
| End of period | 111.11 | 111.11 | 107.38 | 94.75 |
| WTI | | | | |
| Average | 88.23 | 94.15 | 95.11 | 79.61 |
| End of period | 91.82 | 91.82 | 98.83 | 91.38 |
| Average Differential Brent-WTI | 21.90 | 17.53 | 15.80 | 0.73 |
| WCS | | | | |
| Average | 70.12 | 73.12 | 77.96 | 65.38 |
| End of period | 59.16 | 59.16 | 84.37 | 72.87 |
| Average Differential WTI-WCS | 18.11 | 21.03 | 17.15 | 14.23 |
| Condensate (C5 @ Edmonton) Average | 98.14 | 100.88 | 105.34 | 81.91 |

| | | | | |
|---|---|---|---|---|
| Average Differential | | | | |
| WTI-Condensate Premium | (9.91) | (6.73) | (10.23) | (2.30) |
| **Refining Margin 3-2-1 Average Crack Spreads** [2] (US$/bbl) | | | | |
| Chicago | 28.18 | 27.76 | 24.55 | 9.33 |
| Midwest Combined ("Group 3") | 28.49 | 28.56 | 25.26 | 9.48 |
| **Natural Gas Average Prices** | | | | |
| AECO ($/GJ) | 2.90 | 2.28 | 3.48 | 3.91 |
| NYMEX (US$/MMBtu) | 3.40 | 2.79 | 4.04 | 4.39 |
| Basis Differential NYMEX-AECO (US$/MMBtu) | 0.31 | 0.38 | 0.31 | 0.40 |
| **U.S./Canadian Dollar Exchange Rate** | | | | |
| Average | 1.009 | 1.001 | 1.012 | 0.971 |

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

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

### *Crude Oil Benchmarks*

The Brent benchmark is representative of global crude oil prices and is also a better indicator than WTI of changes in inland refined product prices, which are tied to global markets. In 2012, the average price of Brent crude oil was roughly the same as in 2011, averaging near US$112 per barrel, as the effects of weak demand growth, was offset by supply outages caused by operational and geopolitical problems. Demand weakness was the result of weak European and North American economies, as governments addressed fiscal imbalances and slowing Chinese growth, as authorities tried to reduce the inflated value of products within the Chinese economy.

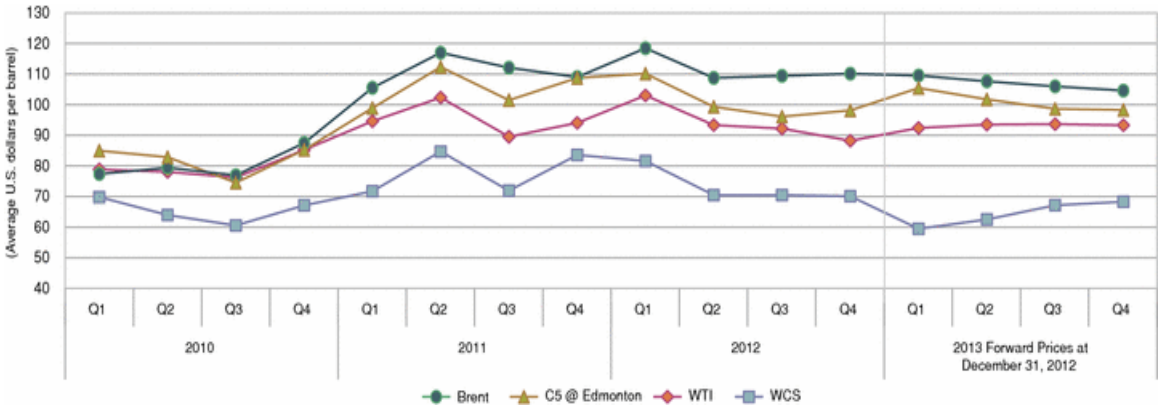
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI has been trading at a significant discount to Brent prices for the past two



Table of Contents

years as inland supply growth has strained the capacity of takeaway transportation from inland markets. These discounts widened somewhat in 2012 as additional transportation capacity provided by reversing the Seaway pipeline to flow out of the U.S. Midwest, was more than offset by growth in inland supply.

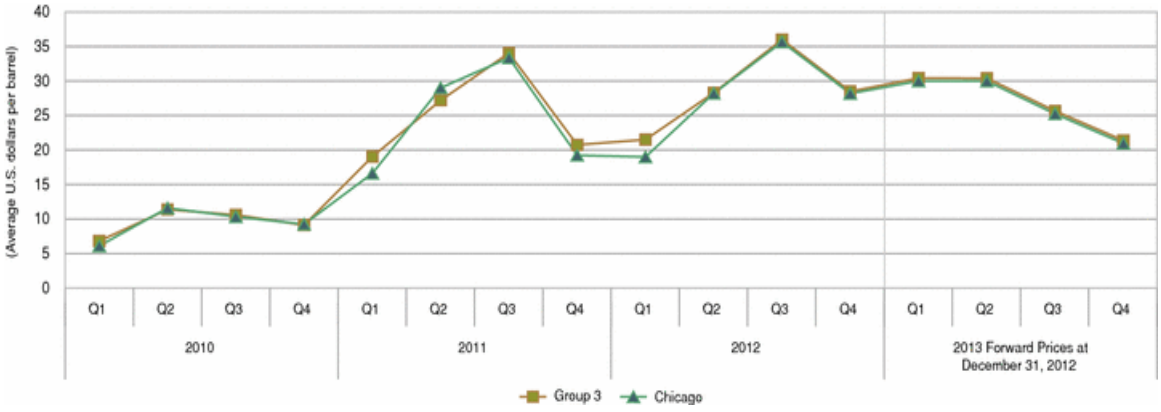
WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential widened in 2012, primarily due to greater transportation congestion out of the Western Canadian Sedimentary Basin ("WCSB"), despite increased supply outages and availability of rail capacity.




Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The WTI-Condensate differential is the Edmonton benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. Condensate differentials at Edmonton weakened in 2012 by US$3.50 per barrel due largely to the continued strong growth in North American condensate supply, mostly from the Eagleford basin in Texas, offset partially by increased costs of transport to the Edmonton market.

### *Refining 3-2-1 Crack Spread Benchmarks*

Average 2012 crack spreads in the U.S. inland Chicago and Group 3 markets increased from strong 2011 levels due to increased North American crude oil discounts and global refinery closures.




Benchmark crack spreads are a simplified view of the market based on LIFO and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and feedstock costs based on first in, first out accounting basis.

***Other Benchmarks***

Average natural gas prices in 2012 fell sharply from 2011 levels due to one of the warmest winters on record coupled with continued strong growth in North American supply despite a falling rig count. In order to create sufficient demand to offset these imbalances, gas prices fell sufficiently to induce fuel switching away from coal-fired power generation to gas-fired power generation.



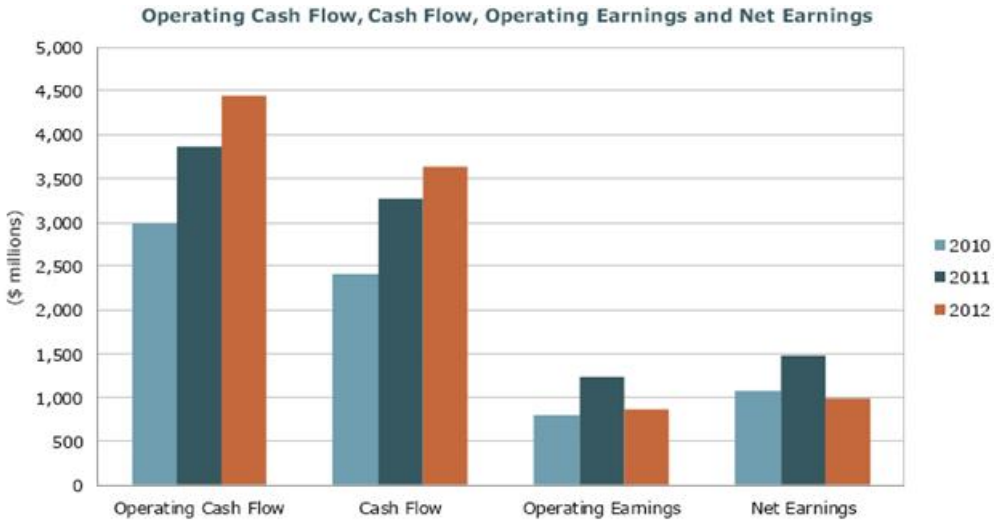
Table of Contents

A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar increases our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. During 2012, the Canadian dollar weakened slightly relative to the U.S. dollar, but remained close to parity.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section:




| ($ millions, except per share amounts) | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| **Revenues** | 16,842 | 7% | 15,696 | 24% | 12,641 |
| **Operating Cash Flow** [1] | 4,436 | 15% | 3,862 | 30% | 2,981 |
| **Cash Flow** [1] | 3,643 | 11% | 3,276 | 36% | 2,412 |
| per Share – Diluted | 4.80 | 11% | 4.32 | 35% | 3.20 |
| **Operating Earnings** [1] | 866 | -30% | 1,239 | 55% | 799 |
| per Share – Diluted | 1.14 | -30% | 1.64 | 55% | 1.06 |
| **Net Earnings** | 993 | -33% | 1,478 | 37% | 1,081 |
| per Share – Basic | 1.31 | -33% | 1.96 | 36% | 1.44 |
| per Share – Diluted | 1.31 | -33% | 1.95 | 36% | 1.43 |
| **Total Assets** | 24,216 | 9% | 22,194 | 12% | 19,840 |
| **Total Long-Term Financial Liabilities** | 6,128 | 13% | 5,411 | -4% | 5,618 |
| **Capital Investment** [2] | 3,368 | 24% | 2,723 | 29% | 2,115 |
| **Cash Dividends** | 665 | 10% | 603 | 0% | 601 |
| per Share | 0.88 | 10% | 0.80 | 0% | 0.80 |

*(1) Non-GAAP Measure and defined in this MD&A.*
*(2) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.*



Table of Contents

### Revenue Variance

| ($ millions) | 2012 vs. 2011 | 2011 vs. 2010 |
|---|---|---|
| **Revenues, Comparative Year** | 15,696 | 12,641 |
| Increase (Decrease) due to: | | |
| Oil Sands | 866 | 584 |
| Conventional | (227) | 9 |
| Refining and Marketing | 731 | 2,397 |
| Corporate and Eliminations | (224) | 65 |
| **Revenues, End of Year** | 16,842 | 15,696 |

Oil Sands revenues increased 29 percent primarily due to increased crude oil and condensate volumes, partially offset by decreased average crude oil prices. Conventional revenues decreased by 11 percent as crude oil and NGLs production increases were offset by lower crude oil prices and lower natural gas production and prices. Revenues generated by the Refining and Marketing segment rose by seven percent as a result of increased refined product output and higher refined product prices, despite reduced output levels during planned turnarounds. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility also increased revenues. Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

### Operating Cash Flow

Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Revenues** [1] | 17,125 | 15,755 | 12,765 |
| (Add Back) Deduct: | | | |
| Purchased Product [1] | 9,506 | 9,149 | 7,674 |
| Transportation and Blending | 1,798 | 1,369 | 1,065 |
| Operating Expenses [1] | 1,684 | 1,407 | 1,289 |
| Production and Mineral Taxes | 37 | 36 | 34 |
| Realized Gain on Risk Management Activities [1] | (336) | (68) | (278) |
| **Operating Cash Flow** | 4,436 | 3,862 | 2,981 |

*(1) Excludes any revenues, purchased product and operating expenses included in the Corporate and Eliminations segment. See the notes to the Consolidated Financial Statements for details.*



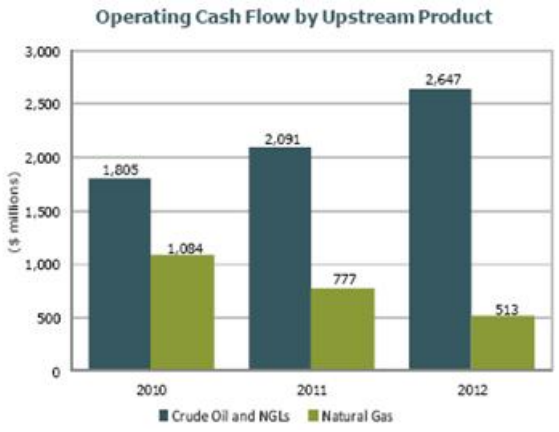



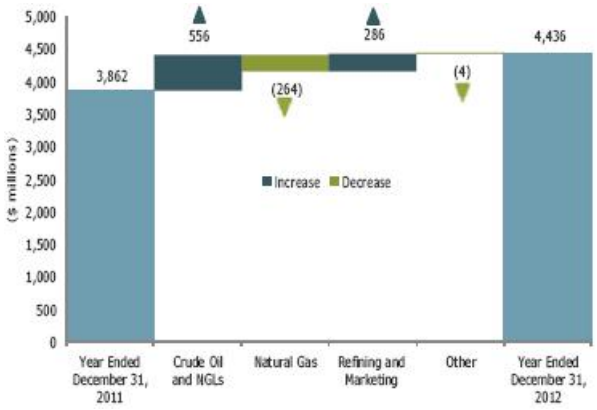



Table of Contents

#### *Operating Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011*

Overall, operating cash flow increased $574 million or 15 percent as operating cash flow from crude oil and NGLs and Refining and Marketing increased 27 percent and 29 percent, respectively.

The increase in operating cash flow from crude oil and NGLs was driven by increased production volumes, partially offset by lower average crude oil sales prices and higher operating costs. Operating cash flow from natural gas declined $264 million (34 percent), as a result of lower average sales prices combined with reduced production volumes from expected natural declines and the divestiture of a non-core natural gas property in the first quarter of 2012. Refining and Marketing operating cash flow rose on improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.




Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

### Cash Flow

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

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Cash From Operating Activities** | 3,420 | 3,273 | 2,591 |
| (Add Back) Deduct: | | | |
| Net Change in Other Assets and Liabilities | (113) | (82) | (55) |
| Net Change in Non-Cash Working Capital | (110) | 79 | 234 |
| **Cash Flow** | 3,643 | 3,276 | 2,412 |

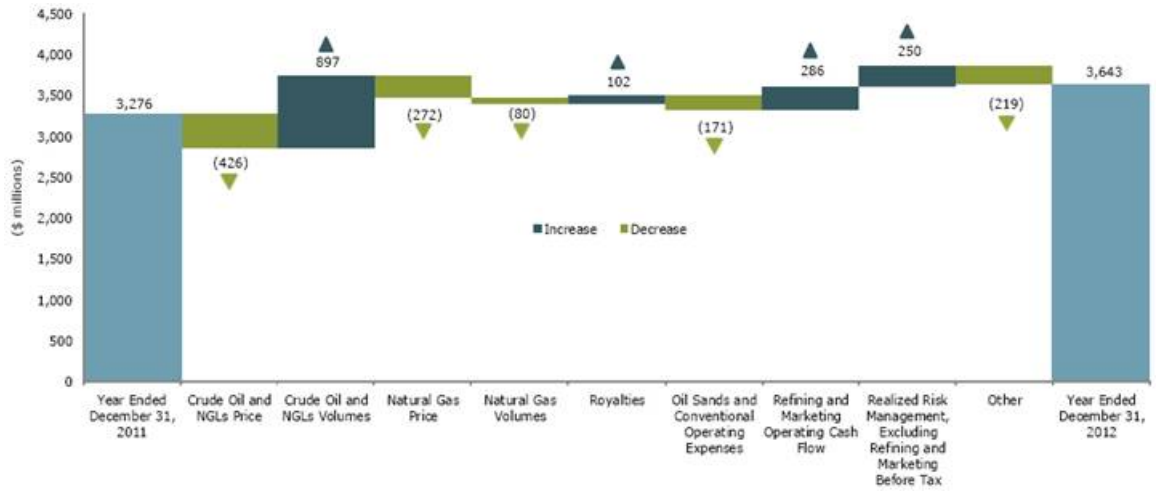
#### *Cash Flow Variance for the Year Ended December 31, 2012 compared to December 31, 2011*

In 2012, our cash flow increased $367 million or 11 percent primarily due to:

- A 25 percent increase in our crude oil and NGLs sales volumes;
- An increase in operating cash flow from Refining and Marketing of $286 million due to improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds;
- Realized risk management gains before tax, excluding Refining and Marketing, of $332 million compared to gains of $82 million in 2011; and
- A decrease in royalties of $102 million primarily as a result of increased capital investment at Foster Creek and Pelican Lake. In 2011, inclusion of the Foster Creek expansion phases F, G and H capital investment was approved as part of the Foster Creek royalty calculation, resulting in a $65 million reduction in royalties in 2011.



Table of Contents




The increases in our cash flow for 2012 were partially offset by:

- A 10 percent decrease in the average realized sales price of crude oil and NGLs to $65.79 per barrel;
- A 34 percent decrease in the average natural gas sales price to $2.42 per Mcf;
- An increase in operating expenses of $171 million, primarily from increased crude oil production at all of our upstream properties with crude oil per barrel operating costs increasing three percent to $13.99 per barrel;
- Increase in other expenditures of $219 million, primarily related to a $168 million increase in current income tax due to $68 million of withholding tax on a U.S. dividend, higher U.S. income tax and higher Canadian tax due to improved operating cash flow from our Canadian operations; and
- A nine percent decline in natural gas production, primarily as a result of expected natural declines and the divestiture of a non-core property early in the first quarter of 2012.

### Operating Earnings

Operating earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating earnings is defined as net earnings excluding the after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax gains (losses) on non-operating foreign exchange, after-tax effect of gains (losses) on divestiture of assets and the effect of changes in statutory income tax rates.

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Net Earnings** | 993 | 1,478 | 1,081 |
| (Add Back) Deduct: | | | |
| Unrealized Risk Management Gains (Losses), after-tax [1] | 43 | 134 | 34 |
| Non-Operating Unrealized Foreign Exchange Gains (Losses), after-tax [2] | 84 | 14 | 153 |
| Gain (Loss) on Divestiture of Assets, after-tax | - | 91 | 83 |
| Gain (Loss) on Bargain Purchase, after-tax | - | - | 12 |
| **Operating Earnings** | 866 | 1,239 | 799 |

*(1) The unrealized risk management gains (losses), after-tax include the reversal of unrealized gains (losses) recognized in prior periods.*

*(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.*

Operating earnings of $866 million, decreased $373 million or 30 percent primarily due to a goodwill impairment, increased DD&A and exploration expense, partially offset by higher cash flow as discussed above.



Table of Contents

### Net Earnings Variance

| ($ millions) | 2012 vs. 2011 | 2011 vs. 2010 |
|---|---|---|
| **Net Earnings, Comparative Year** | 1,478 | 1,081 |
| Increase (Decrease) due to: | | |
| Operating Cash Flow | 574 | 881 |
| Corporate and Eliminations: | | |
| Unrealized Risk Management Gains (Losses), after-tax | (91) | 100 |
| Unrealized Foreign Exchange Gains (Losses) | 28 | (27) |
| Gain (Loss) on Divestiture of Assets | (107) | (9) |

| | | |
|---|---|---|
| Expenses [1] | (52) | (86) |
| Depreciation, Depletion and Amortization | (290) | 7 |
| Goodwill Impairment | (393) | - |
| Exploration Expense | (68) | 3 |
| Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gains (Losses) | (86) | (472) |
| **Net Earnings, End of Year** | 993 | 1,478 |

*(1) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net and Corporate and Eliminations operating expenses.*

Year over year, our net earnings decreased $485 million or 33 percent, primarily as a result of a goodwill impairment and the absence of gains recorded on divestitures of assets in 2012. Significant factors that impacted our net earnings for the year include:

- Goodwill impairment of $393 million on the carrying amount of the Suffield cash generating unit ("CGU") within our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area;
- An increase of $290 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs associated with total proved reserves and increased depreciable costs in Refining and Marketing, partially offset by decreased natural gas production;
- No gains recorded on divestitures of assets during 2012 as compared to a gain of $107 million in 2011;
- Unrealized risk management gains, after-tax, of $43 million, compared to gains of $134 million in 2011;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $769 million, compared to $683 million in 2011;
- An increase in exploration expense of $68 million; and
- An increase of $57 million for general and administrative expenses primarily due to higher staffing and office support costs.

Partially offset by:

- Increased operating cash flow as discussed previously; and
- Unrealized foreign exchange gains of $70 million compared to a gain of $42 million in 2011, consistent with the strengthening of the Canadian dollar exchange rate at December 31, 2012 resulting from the translation of our U.S. dollar long-term debt and Partnership Contribution Receivable.

### Net Capital Investment

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Oil Sands | 2,211 | 1,415 | 857 |
| Conventional | 848 | 788 | 526 |
| Refining and Marketing | 118 | 393 | 656 |
| Corporate and Eliminations | 191 | 127 | 76 |
| **Capital Investment** | 3,368 | 2,723 | 2,115 |
| Acquisitions [2] | 114 | 71 | 86 |
| Divestitures | (76) | (173) | (307) |
| **Net Capital Investment [1]** | 3,406 | 2,621 | 1,894 |

(1) *Includes expenditures on PP&E and E&E.*
(2) *Asset acquisition included the assumption of a decommissioning liability of $33 million.*

Oil Sands capital investment increased primarily due to higher spending at Foster Creek on module assembly and facility construction for phase F, piling work, steel fabrication, module assembly and major equipment procurement for phase G and design engineering for phase H. In addition, Foster Creek also incurred main facility and infrastructure spending. At Christina Lake, the increase in capital investment included drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, as well as phase F site preparation, engineering and major equipment fabrication. Pelican Lake capital investment included infill drilling for expansion of the polymer flood, facility expansion, pipeline construction and maintenance capital. Capital investment in 2012 included the drilling of 473 gross stratigraphic test wells, down from the 480 gross wells drilled during 2011. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.



Table of Contents

Conventional capital investment in 2012 was centered on the development of our crude oil properties including drilling, completion and major facilities work in Saskatchewan as well as drilling completion and tie-in in Alberta focused on tight oil opportunities.

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

Included in our capital investment is spending on technology development. Our teams look for ways to either improve existing technology or pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas. One of our ongoing objectives is to advance technologies that increase production while minimizing the use of water, natural gas, electricity and land. This philosophy is evidenced through the use of our Wedge Well™ technology at Foster Creek and Christina Lake, the use of enhanced start-up techniques at Christina Lake phase C and the development of our SkyStrat™ drilling rig used for the drilling of stratigraphic wells in remote areas.

Capital investment in our Corporate and Eliminations segment was for information technology and tenant improvements to new office space.

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

#### *Acquisitions and Divestitures*

The acquisitions were primarily for oil sands properties adjacent to our Telephone Lake and Narrows Lake properties as well as producing conventional crude oil properties in Alberta and Saskatchewan located adjacent to existing production. Divestitures in 2012 were mainly related to the sale of our Boyer natural gas property, located in northern Alberta, in the first quarter.

### Capital Investment Decisions

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

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

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow.

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Cash Flow | 3,643 | 3,276 | 2,412 |
| Capital Investment (Committed and Growth) | 3,368 | 2,723 | 2,115 |
| Free Cash Flow [1] | 275 | 553 | 297 |
| Dividends Paid | 665 | 603 | 601 |

| | | | |
|---|---|---|---|
| | (390) | (50) | (304) |

*(1) Free Cash Flow is a non-GAAP measure defined as cash flow less capital investment.*

Over the next decade, we expect to increase our net crude oil production to approximately 500,000 barrels per day. In order to meet these project targets, we anticipate capital expenditures to average between $3.0 and $3.5 billion a year. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. In August 2012, we completed a public debt offering for the principal amount of US$1.25 billion. As at December 31, 2012, we have cash and cash equivalents of approximately $1.2 billion to fund future capital investment. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of our financial metrics.



Table of Contents

## REPORTABLE SEGMENTS

Our reportable segments are as follows:

**Oil Sands,** includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

**Conventional**, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the 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. 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 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.

### Revenue by Reportable Segment

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Oil Sands | 3,873 | 3,007 | 2,423 |
| Conventional | 1,896 | 2,123 | 2,114 |
| Refining and Marketing | 11,356 | 10,625 | 8,228 |
| Corporate and Eliminations | (283) | (59) | (124) |
| | 16,842 | 15,696 | 12,641 |

## OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects and we also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Grand Rapids and Telephone Lake. The Oil Sands segment also includes the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in 2012 include:
- Early completion of phase D at Christina Lake with production starting up in the third quarter of 2012;
- Foster Creek demonstrating excellent operating performance in 2012, exceeding nameplate capacity of 120,000 gross barrels per day for six months of the year;
- Expansion work at phases F, G and H at Foster Creek is progressing with added production capacity from phase F expected in the third quarter of 2014; and
- Receiving regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A.



Table of Contents

### Oil Sands – Crude Oil

#### *Financial Results*

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Gross Sales** | 4,037 | 3,217 | 2,610 |
| Less: Royalties | 215 | 282 | 276 |
| **Revenues** | 3,822 | 2,935 | 2,334 |
| **Expenses** | | | |
| Transportation and Blending | 1,651 | 1,229 | 934 |
| Operating | 548 | 409 | 339 |
| (Gains) Losses on Risk Management | (62) | 87 | 14 |
| **Operating Cash Flow** | 1,685 | 1,210 | 1,047 |
| Capital Investment | 2,203 | 1,401 | 850 |
| **Operating Cash Flow in Excess (Deficient) of Related Capital Investment** | (518) | (191) | 197 |

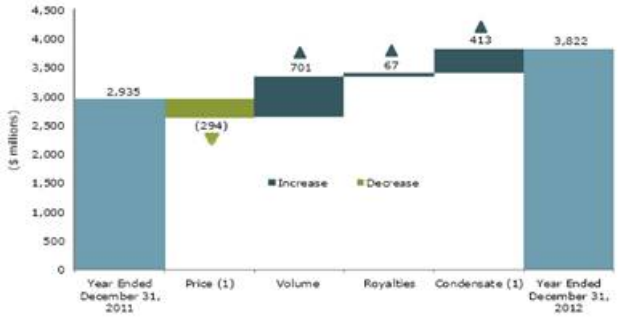
Capital expenditures in excess of operating cash flow for the Oil Sands segment are funded through operating cash flow generated by our conventional and refining operations.

#### *Revenues*

### Pricing

In 2012, our average crude oil sales price was $60.84 per barrel, an 11 percent decrease from 2011, generally consistent with the decrease in the WCS benchmark price.

In 2012, with the introduction of a new crude stream to the market, CDB, approximately 74 percent (2011 – 12 percent) of our Christina Lake production was sold as CDB which sells at a discount to WCS. As the year progressed, the discount from WCS decreased as CDB became more widely accepted as a crude stream. The remaining Christina Lake production is being sold as part of the WCS stream and is subject to a quality equalization charge.




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

### Production

In 2012, the substantial increase in production at Christina Lake resulted from the start-up of phase C in the third quarter of 2011 and phase D coming on production in late July 2012, three months ahead of schedule. Foster Creek production increased due to improved well performance and plant optimization. In 2012, both Christina Lake and Foster Creek achieved new single day production highs of 93,936 and 130,580 gross barrels per day, respectively. Pelican Lake production rose steadily with production averaging 10 percent higher than 2011. The increases at Pelican Lake resulted from infill wells being brought on production in 2012. In addition, 2011 production was curtailed due to a scheduled plant turnaround and wild fires.

| Crude Oil (barrels per day) | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| Foster Creek | 57,833 | 5% | 54,868 | 7% | 51,147 |
| Christina Lake | 31,903 | 173% | 11,665 | 48% | 7,898 |
| | 89,736 | 35% | 66,533 | 13% | 59,045 |
| Pelican Lake | 22,552 | 10% | 20,424 | -11% | 22,966 |
| | 112,288 | 29% | 86,957 | 6% | 82,011 |

### Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined by the Canadian dollar equivalent WTI benchmark price. Royalties at Christina Lake are based on a pre-payout, monthly calculation using the pre-payout royalty rate applied to the net revenue from the project, which is impacted by volumes and realized prices. Foster Creek and Pelican Lake royalties are based on a post-payout, annualized calculation using the post-payout royalty rate applied to a net profit from the



Table of Contents

project which is impacted by volumes, realized prices as well as allowed operating and capital costs.

Royalties decreased $67 million during 2012, primarily due to increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets and a $65 million decrease in 2011 royalties upon receiving approval for the inclusion of Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for 2012 were 11.8 percent at Foster Creek (2011 – 16.8 percent), 6.2 percent at Christina Lake (2011 – 5.2 percent) and 5.0 percent at Pelican Lake (2011 – 11.5 percent).

## *Expenses*

### Transportation and Blending

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce its viscosity in order to transport the product to market. Transportation and blending costs rose $422 million or 34 percent in 2012. The majority of the cost increase, $413 million, stems from additional condensate volumes required to blend as a result of higher production at Christina Lake and Foster Creek. This was partially offset by lower transportation charges on the Trans Mountain pipeline system under our long-term commitment for firm service, which commenced in February 2012.

### Operating

Our operating costs for 2012 were primarily for workforce, workover activities, repairs and maintenance, chemical usage and fuel costs at Foster Creek and Christina Lake. In total, operating costs increased $139 million in 2012 mainly due to higher staffing levels, fuel consumption, chemicals and fluid and waste handling and trucking costs associated with the start-up of Christina Lake phases C and D which increased gross production capacity by 80,000 barrels per day. Overall, on a per barrel basis, operating costs were $13.33 (2011 – $13.27). On a per barrel basis, Christina Lake operating costs decreased 36 percent to $12.95 per barrel due to the increase in production. Foster Creek operating costs increased $0.65 per barrel to $11.99 per barrel due to increased workforce costs, higher waste handling, trucking and workover activity. Operating costs increased $2.22 per barrel at Pelican Lake primarily as the result of additional workover activities, workforce and increased polymer consumption as a result of the expansion of the polymer flood.

### Risk Management

Risk management activities resulted in realized gains of $62 million (2011 – losses of $87 million), consistent with our 2012 contract prices exceeding average benchmark prices in 2012.

### Oil Sands – Natural Gas

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production decreased to 33 MMcf per day in 2012 (2011 – 37 MMcf per day) as the result of anticipated natural declines, partially offset by a reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues in the first quarter of 2012 and reduced volumes in the fourth quarter as a result of lower natural gas prices.

Reduced natural gas production in combination with lower prices resulted in operating cash flow declining to $31 million for 2012 (2011 – $52 million).

### Oil Sands – Capital Investment

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Foster Creek | 735 | 429 | 277 |
| Christina Lake | 579 | 472 | 346 |

| | | | |
|---|---|---|---|
| | **1,314** | 901 | 623 |
| Pelican Lake | **518** | 317 | 104 |
| Narrows Lake | **44** | 19 | 10 |
| Telephone Lake | **138** | 61 | 27 |
| Grand Rapids | **65** | 31 | 59 |
| Other [1] | **132** | 86 | 34 |
| **Capital Investment** [2] | **2,211** | 1,415 | 857 |

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

Oil Sands capital investment in 2012 has been primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, facility expansion and infill drilling activities related to our Pelican Lake polymer flood, drilling of stratigraphic test wells to support the development of our Oil Sands projects and commencing operation of our dewatering pilot at Telephone Lake in the fourth quarter. In addition, capital investment increased at Narrows Lake as site preparation commenced for phase A. Construction of the phase A plant is scheduled to start in the third quarter of 2013.



Table of Contents

### *Foster Creek*

Foster Creek capital investment increased in 2012 compared to 2011 primarily as a result of higher phase F spending on module assembly and facility construction, phase G spending on piling work, steel fabrication, module assembly and major equipment procurement and phase H design engineering. Capital includes the drilling of 141 gross stratigraphic test wells in 2012 (2011 – 118 wells) and higher spending on the main facility and infrastructure. First production at phase F is expected in the third quarter of 2014 increasing production capacity by 45,000 gross barrels per day.

### *Christina Lake*

Christina Lake capital investment increased in 2012 compared to 2011 primarily due to drilling of SAGD well pairs related to facility ramp-up, phase E facility construction, phase F site preparation, engineering and major equipment fabrication and phase G design engineering, in addition to maintenance capital. Capital investment also included the drilling of stratigraphic test wells (2012 – 29 gross wells; 2011 – 63 gross wells). The increases in capital investment were partially offset by the completion of phases C and D construction in the second quarters of 2011 and 2012, respectively.

### *Pelican Lake*

Pelican Lake capital investment in 2012 was primarily related to infill drilling to progress the polymer flood, facilities expansions, pipeline construction and maintenance capital. Facilities spending focused on expanding fluid handling capacity at Pelican Lake through additions and upgrades to our crude oil treating units and emulsion pipelines.

### *Telephone Lake*

At Telephone Lake capital investment was primarily related to drilling, infrastructure, fuel storage and facility construction related to the dewatering pilot which started up in the fourth quarter of 2012.

### *Gross Production Wells Drilled* [1]

| | **2012** | 2011 | 2010 |
|---|---|---|---|
| Foster Creek | **28** | 21 | 37 |
| Christina Lake | **32** | 19 | 32 |
| | **60** | 40 | 69 |
| Pelican Lake | **76** | 31 | 12 |
| Grand Rapids | **1** | - | 1 |
| Other | **-** | 3 | - |
| | **137** | 74 | 82 |

*(1) Includes wells drilled using our Wedge Well™ technology.*

### Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned with additional production capacity from phase F expected in the third quarter of 2014. Progress is also being made for phase G on module assembly and facility construction and on phase H engineering and procurement is continuing with piling work and module assembly, scheduled to start in 2013. We anticipate submitting an application to regulators in 2013 for an additional expansion, phase J.

Production from phase E at Christina Lake is anticipated in the third quarter of 2013, a few months earlier than originally planned. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G. Expansion work on these phases is continuing in 2013 with module assembly, facility construction and procurement for phase F and detailed engineering for phase G.

In 2012, Narrows Lake received regulatory approval for phases A, B and C, and partner approval for phase A. Site preparation is underway, with construction of the phase A plant scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $140 million and $160 million in 2013.

Additional capital of approximately $270 to $300 million is expected to be invested in the emerging SAGD projects including Grand Rapids and Telephone Lake in 2013. We anticipate regulatory approval for Grand Rapids by the end of 2013. Steam injection started on the second pilot well pair during the third quarter of 2012, with first production expected early in 2013. At Telephone Lake, we are advancing the regulatory application for the project and continuing with operation of the dewatering pilot. We anticipate receiving regulatory approval in 2014.



Table of Contents

### *Stratigraphic Test Wells*

Consistent with our strategy to unlock the value of our resource base, we completed another large stratigraphic test well program in the first quarter of 2012. The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake are to support the expansion phases, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs between the end of the fourth quarter and the end of the first quarter. In 2012 we developed the SkyStrat™ drilling rig, which uses a helicopter and an experimental lightweight drilling rig to allow stratigraphic well drilling to be

completed in remote exploratory drilling locations year-round.

Our 2012 stratigraphic test well program provided the primary basis for the 1.4 billion barrel increase to our economic bitumen best estimate contingent resources as results from the program caused prospective resources to be reclassified as contingent resources. Additional information about our resources, including definitions and year end results, is included in the Oil and Gas Reserves and Resources section of this MD&A.

### Gross Stratigraphic Test Wells Drilled

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Foster Creek | 141 | 118 | 82 |
| Christina Lake | 29 | 63 | 24 |
| | 170 | 181 | 106 |
| Pelican Lake | 5 | 57 | - |
| Narrows Lake | 42 | 47 | 39 |
| Grand Rapids | 62 | 59 | 71 |
| Telephone Lake | 29 | 40 | 26 |
| Borealis | 59 | 44 | - |
| Other | 106 | 52 | 17 |
| | 473 | 480 | 259 |

## CONVENTIONAL

Our Conventional operations include the development and production of crude oil and NGLs and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In Saskatchewan, our Conventional properties are predominantly crude oil producing properties, most notably the carbon dioxide enhanced oil recovery project in Weyburn. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to continue to assess the potential of new crude oil projects within our existing properties, as well as new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2012 include:

- Alberta crude oil and NGLs production averaging 30,357 barrels per day, increasing 10 percent primarily due to successful tight oil drilling programs and fewer weather and access issues than in 2011;
- Completing the construction and commissioning of batteries in both the Bakken and Lower Shaunavon areas, including all supporting infrastructure, to support production in the respective areas;
- Bakken and Lower Shaunavon crude oil and NGLs production averaging 6,480 barrels per day, a 79 percent increase due to ongoing drilling; and
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $439 million, a decrease of 30 percent from 2011. In the low price environment, we have chosen to restrict natural gas capital spending for the past several years.

### Conventional – Crude Oil and NGLs

#### *Financial Results*

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Gross Sales** | 1,559 | 1,492 | 1,229 |
| Less: Royalties | 166 | 193 | 153 |
| **Revenues** | 1,393 | 1,299 | 1,076 |
| **Expenses** | | | |
| Transportation and Blending | 126 | 104 | 86 |
| Operating | 294 | 244 | 199 |
| Production and Mineral Taxes | 34 | 27 | 28 |
| (Gains) Losses on Risk Management | (23) | 43 | 5 |
| **Operating Cash Flow** | 962 | 881 | 758 |
| Capital Investment | 805 | 686 | 363 |
| **Operating Cash Flow in Excess of Related Capital Investment** | 157 | 195 | 395 |



Table of Contents

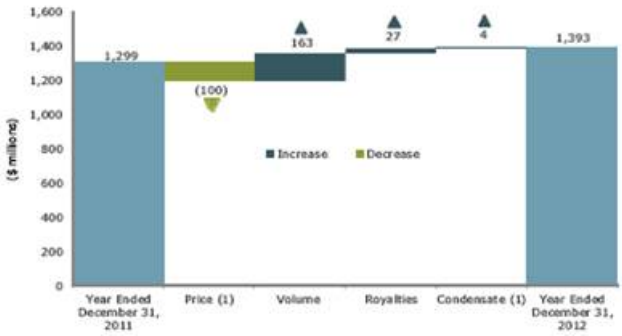
#### *Revenues*

### Pricing

Our average crude oil and NGLs sales price in 2012 decreased six percent to $76.25 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

### Production

Our crude oil and NGLs production increased 12 percent in 2012 as a result of successful drilling completion and tie-in programs. Production in Alberta increased 10 percent to an average of 30,357 barrels per day and production in Saskatchewan increased 15 percent to an average of 22,758 barrels per day.




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

| (barrels per day) | 2012 | 2012 vs. 2011 | 2011 | 2011 vs. 2010 | 2010 |
|---|---|---|---|---|---|
| **Heavy Oil** | | | | | |
| Alberta | 16,015 | 2% | 15,657 | -6% | 16,659 |
| **Light and Medium Oil** | | | | | |
| Alberta | 13,378 | 24% | 10,763 | -1% | 10,854 |
| Saskatchewan | 22,693 | 15% | 19,761 | 7% | 18,492 |
| **NGLs** | 1,029 | -7% | 1,101 | -6% | 1,171 |
| | 53,115 | 12% | 47,282 | 0% | 47,176 |

### Royalties

Royalties decreased $27 million largely due to lower royalties in Weyburn primarily as a result of lower realized crude oil prices. The effective crude oil royalty rate in 2012 for the Conventional segment was 11.8 percent (2011 – 14.2 percent). Most of our crude oil and NGLs production in the Conventional segment is located on fee land which results in mineral tax recorded within production and mineral taxes.

### *Expenses*

#### Transportation and Blending

Transportation and blending costs increased $22 million in 2012. The overall cost of condensate used in blending increased $4 million as slightly lower prices only partially offset increased usage in our heavy oil operations. Transportation costs increased $18 million due to higher produced volumes, an increase of trucking expenses attributable to the clean oil sold out of Shaunavon prior to the construction of the pipeline connected battery, a higher proportion of our volumes being subject to spot pipeline tolls and increased costs associated with accessing new markets, such as transporting our growing light and medium crude oil production by rail.

#### Operating

Operating costs are predominantly comprised of workover activities, electricity, repairs and maintenance and workforce. Operating costs increased $50 million in 2012 primarily due to a combination of fluid waste handling and trucking costs, additional workover activities, repairs and maintenance in connection with single well batteries and higher workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil which has resulted in higher crude oil production.

#### Risk Management

Risk management activities in 2012 resulted in realized gains of $23 million (2011 – loss of $43 million), consistent with our contract prices exceeding the average benchmark prices.

#### Operating Cash Flow in Excess of Capital Investment

Operating cash flow from crude oil and NGLs in excess of capital investment decreased by $38 million in 2012 as the $81 million increase in operating cash flow was more than offset by the $119 million increase in capital investment which was focused on drilling, completions and facilities work in Alberta and Saskatchewan.



Table of Contents

## Conventional – Natural Gas

### *Financial Results*

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Gross Sales** | 496 | 825 | 1,042 |
| Less: Royalties | 6 | 12 | 17 |
| **Revenues** | 490 | 813 | 1,025 |
| **Expenses** | | | |
| Transportation and Blending | 19 | 34 | 44 |
| Operating | 215 | 240 | 231 |
| Production and Mineral Taxes | 3 | 9 | 6 |
| Gains on Risk Management | (229) | (195) | (263) |
| **Operating Cash Flow** | 482 | 725 | 1,007 |
| Capital Investment | 43 | 102 | 163 |
| **Operating Cash Flow in Excess of Related Capital Investment** | 439 | 623 | 844 |

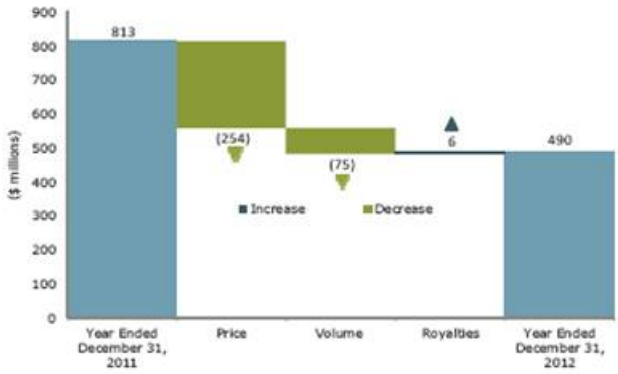
### *Revenues*

#### Pricing

Our average natural gas sales price in 2012 decreased to $2.42 per Mcf compared to $3.65 per Mcf in 2011, consistent with the decline in the benchmark AECO price.

#### Production

Our Conventional natural gas production decreased nine percent to 561 MMcf per day, primarily due to expected natural declines. Further production decreases stemmed from the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 21 MMcf per day. Excluding the impact of the Boyer divestiture, our natural gas production would have been six percent lower than in 2011.




#### Royalties

Royalties decreased $6 million in 2012 due to lower volumes in combination with lower prices. The average royalty rate in 2012 was 1.3 percent (2011 – 1.5 percent). Most of our natural gas production in the Conventional segment is located on fee land where we hold mineral rights which results in mineral tax recorded within production and mineral taxes.

### *Expenses*

#### Transportation

Transportation costs decreased $15 million due to lower production volumes.

#### Operating

Our operating expenses are composed largely of property taxes and lease costs, repairs and maintenance and workforce. Operating expenses decreased $25 million in 2012. The reduction in natural gas activity and the disposition of the Boyer property early in 2012 resulted in lower repairs and maintenance and workover activity costs.

#### Risk Management

Risk management activities resulted in realized gains in 2012 of $229 million (2011 – gains of $195 million) consistent with our 2012 contract prices exceeding the 2012 average benchmark price.

#### Operating Cash Flow in Excess of Capital Investment

Operating cash flow from natural gas in excess of capital investment decreased $184 million primarily due to lower operating cash flow partially offset by a $59 million reduction in capital investment.



Table of Contents

**Conventional – Capital Investment** [1]

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Crude Oil and NGLs | 805 | 686 | 363 |
| Natural Gas | 43 | 102 | 163 |
| | 848 | 788 | 526 |

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

Capital investments in our Conventional segment focused on crude oil opportunities. Capital was invested in our tight oil drilling programs in Saskatchewan and southeast Alberta. In addition, drilling and facilities work continued in Weyburn. Spending on natural gas activities was reduced in response to low natural gas prices.

Crude oil and NGLs wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

***Conventional Drilling Activity***

| (net wells, unless otherwise stated) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Crude Oil and NGLs | 276 | 325 | 180 |
| Natural Gas | - | 65 | 495 |
| Recompletions | 977 | 1,122 | 1,194 |
| Gross Stratigraphic Test Wells | 14 | 11 | 9 |

Subsequent to December 31, 2012, Management decided to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The public sales process is expected to be launched in late February 2013. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. Operating results from these properties are included in the Conventional segment.

## REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against reduced crude oil prices by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors related to our Refining and Marketing segment in 2012 include:

- Increased total heavy crude oil processing capacity to between 235,000 to 255,000 barrels per day (dependent on the quality of heavy crude oil that is economically available) as a result of a full year of operations from the CORE project at the Wood River Refinery, enhancing our ability to further integrate our growing bitumen production;
- Our refineries processing 412,000 barrels per day of crude oil, including 198,000 barrels per day of heavy crude oil, resulting in 433,000 barrels per day of refined product output; and
- Strong refining margins, resulting from higher crack spreads and discounted crude oil feedstock costs.

**Refinery Operations** [1]

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Crude Oil Capacity** (Mbbls/d) | 452 | 452 | 452 |
| **Crude Oil Runs** (Mbbls/d) | 412 | 401 | 386 |
| Heavy Oil | 198 | 126 | 104 |
| Light/Medium | 214 | 275 | 282 |
| **Crude Utilization** (percent) | 91 | 89 | 86 |
| **Refined Products** (Mbbls/d) | 433 | 419 | 405 |
| Gasoline | 216 | 207 | 204 |
| Distillate | 138 | 132 | 124 |
| Other | 79 | 80 | 77 |

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

Refining operations in 2012 reflect the start-up of the CORE project in the fourth quarter of 2011, which has increased heavy crude oil runs and refined product output. On a 100 percent basis, our refineries had a capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 235,000 to 255,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy oil production.

Our crude utilization represents the percentage of crude oil, heavy and other, that is processed in our refineries relative to the total capacity. The amount of heavy crude oils processed, such as WCS and CDB, is dependent on the quality of available crude oils with the total crude input slate being optimized to maximize economic benefit. The amount of heavy crude processed increased by 72,000 barrels per day, a 57 percent increase.

Clean product yield is the percentage output of high value product from every barrel of inputs going into our refineries. Our clean product yield has increased as a result of the start-up of the CORE project which increased our processing capacity of blended heavy crude oil. Total refined product



Table of Contents

output increased by three percent over 2011 with the proportion of gasoline, distillate and other refined products remaining relatively the same.

**Financial Results**

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Revenues** | 11,356 | 10,625 | 8,228 |

| | | | |
|---|---|---|---|
| Purchased Product | **9,506** | 9,149 | 7,674 |
| **Gross Margin** | **1,850** | 1,476 | 554 |
| **Expenses** | | | |
| Operating | **587** | 481 | 488 |
| (Gain) Loss on Risk Management | **(4)** | 14 | (10) |
| **Operating Cash Flow** | **1,267** | 981 | 76 |
| Capital Investment | **118** | 393 | 656 |
| **Operating Cash Flow in Excess (Deficient) of Capital Investment** | **1,149** | 588 | (580) |

### *Gross Margin*

The gross margin for the Refining and Marketing segment increased $374 million in 2012 primarily due to improved refined product output from higher clean product yield at Wood River, higher refined products prices and lower feedstock costs from processing more discounted heavy crude oil as a result of a full year of operations after completion of the CORE project.

### *Operating*

Total operating costs consist mainly of labour, maintenance, utilities and supplies. Operating costs for 2012 increased $106 million due to higher labour and maintenance expenses, consistent with higher utilization, as well as costs related to turnaround activities at both refineries in the fourth quarter. While there is an increase in utility usage at the Wood River Refinery subsequent to the CORE project start-up, utilities costs have declined at both refineries due to significantly lower prices for fuel gas and electricity.

### *Operating Cash Flow*

Operating cash flow from the Refining and Marketing segment increased $286 million to $1,267 million in 2012 as a result of improved refinery output, feedstock costs and crack spreads, partially offset by higher operating costs for planned turnarounds.

#### Refining and Marketing – Capital Investment

| ($ millions) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Wood River Refinery | **54** | 346 | 568 |
| Borger Refinery | **64** | 45 | 87 |
| Marketing | **-** | 2 | 1 |
| | **118** | 393 | 656 |

Our capital investment in the Refining and Marketing segment declined significantly with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

## CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on the long-term power purchase contract. The unrealized gains on risk management were $57 million for the year ended December 31, 2012 (December 31, 2011 – gains of $180 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.



Table of Contents

#### General and Administrative and Financing Costs

| ($ millions) | **2012** | 2011 | 2010 |
|---|---|---|---|
| General and Administrative | **352** | 295 | 246 |
| Finance Costs | **455** | 447 | 498 |
| Interest Income | **(109)** | (124) | (144) |
| Foreign Exchange (Gain) Loss, net | **(20)** | 26 | (51) |
| (Gain) Loss on Divestiture of Assets | **-** | (107) | (116) |
| Other (Income) Loss, net | **(5)** | 4 | (13) |
| | **673** | 541 | 420 |

### *Expenses*

#### General and Administrative

General and administrative expenses increased $57 million in 2012 primarily due to the recruiting of new employees to fill positions created by our growth, which resulted in additional staffing and office support costs, including training and development, information technology and office space.

#### Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In 2012, finance costs were $8 million higher than 2011 due to the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2012 was 5.3 percent (2011 – 5.5 percent).

#### Interest Income

Interest income primarily includes interest earned on our U.S. dollar denominated Partnership Contribution Receivable as well as short-term investments. Interest income in 2012 decreased by $15 million, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

#### Foreign Exchange

For 2012, we recognized net foreign exchange gains of $20 million (2011 – losses $26 million) which includes unrealized gains of $70 million (2011 – unrealized gains of $42 million) and realized losses of $50 million (2011 – realized losses $68 million). The majority of unrealized gains are due to translation of our U.S. dollar denominated debt as a result of a stronger Canadian dollar at December 31, 2012.

#### DD&A

| ($ millions) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Oil Sands | **482** | 347 | 375 |
| Conventional | **905** | 778 | 799 |

| | | | |
|---|---|---|---|
| Refining and Marketing | **146** | 130 | 96 |
| Corporate and Eliminations | **52** | 40 | 32 |
| | **1,585** | 1,295 | 1,302 |

Oil Sands DD&A for 2012 increased $135 million due to higher sales volumes at Foster Creek, Christina Lake and Pelican Lake as well as increased DD&A rates due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment increased $127 million in 2012 due to higher crude oil sales volumes and increased DD&A rates due to higher future development costs associated with higher proved reserves, partially offset by reduced natural gas sales volumes.

Refining and Marketing DD&A increased $16 million in 2012 as the capital costs of the CORE project are now subject to depreciation.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

### Exploration Expense

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability has been established are capitalized as E&E assets. If a field, project or area is determined to no longer be technically feasible or commercially viable and we decide not to continue the E&E activity, the unrecoverable costs are charged to exploration expense.



Table of Contents

During 2012, $68 million of capitalized E&E costs, related primarily to the Roncott asset, a small exploration acreage within the Conventional segment, were deemed not to be commercially viable and technically feasible, and were recognized as exploration expense.

### Goodwill Impairment

For the purpose of impairment testing, goodwill, which arose on the acquisition of exploration and production assets, is allocated to the CGU to which it relates. At December 31, 2012, Cenovus determined that the carrying amount of the Suffield CGU, including the allocated goodwill, exceeded its fair value less costs to sell resulting in an impairment loss of $393 million. The full amount of the impairment was attributed to goodwill. This goodwill arose in 2002 upon the formation of the predecessor corporation. The impairment resulted primarily due to a decline in natural gas and crude oil prices and increased operating costs. In addition, we have had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill, which is not subject to depreciation, depletion and amortization, exceeded its fair value.

### Income Tax Expense

| ($ millions) | **2012** | 2011 | 2010 |
|---|---|---|---|
| Current Tax | | | |
| Canada | **188** | 150 | 82 |
| U.S. | **121** | 4 | - |
| Total Current Tax | **309** | 154 | 82 |
| Deferred Tax | **474** | 575 | 141 |
| | **783** | 729 | 223 |

In 2012, current taxes were higher due to increased cash flow from upstream operations taxed at Canadian rates, additional U.S. income tax from our refining operations and $68 million of withholding tax on the payment of a U.S. dividend. We did not have U.S. federal taxable income as we had sufficient deductions for 2012. U.S. current tax expense is much higher than 2011 because of higher state income tax, where certain loss deductions are deferred to future years for state tax purposes. The decrease in deferred tax is due to lower unrealized risk management gains, the reversal of certain taxable timing differences, partially offset by an increase in income from our refining operations.

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

| ($ millions, except percent amounts) | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Earnings Before Income Tax** | **1,776** | 2,207 | 1,304 |
| **Canadian Statutory Rate** | **25.2%** | 26.7% | 28.2% |
| **Expected Income Tax** | **448** | 589 | 368 |
| Effect of Taxes Resulting From: | | | |
| Foreign Tax Rate Differential | **146** | 82 | (22) |
| Non-deductible Stock-based Compensation | **10** | 18 | 34 |
| Multi-jurisdictional Financing | **(27)** | (50) | (93) |
| Foreign Exchange Gains (Losses) not Included in Net Earnings | **14** | (9) | 28 |
| Non-taxable Capital Gains | **(7)** | (8) | (13) |
| Recognition of Capital Losses | **(22)** | 26 | (107) |
| Adjustments Arising From Prior Year Tax Filings | **33** | 31 | 26 |
| Withholding Tax on Foreign Dividends | **68** | - | - |
| Goodwill Impairment | **99** | - | - |
| Other | **21** | 50 | 2 |
| **Total Tax** | **783** | 729 | 223 |
| **Effective Tax Rate** | **44.1%** | 33.0% | 17.1% |

The Canadian statutory tax rate decreased to 25.2 percent as a result of tax legislation enacted in 2007. The U.S. statutory tax rate has increased to 38.5 percent as a result of the allocation of taxable income to U.S. states.

The increase in our effective tax rate in 2012 is primarily due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, the impairment of goodwill, U.S. withholding tax on the payment of a dividend in 2012 and lower benefits of multi-jurisdictional financing.

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



Table of Contents

Permanent differences include:
- Withholding tax on foreign dividends;
- Goodwill impairment;

- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. The effective rate for 2012 is higher than 2011 due to a change in the weighting of income between our U.S. and Canadian operations.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

## QUARTERLY RESULTS

| ($ millions, except per share amounts) | Q4 2012 | Q3 2012 | Q2 2012 | Q1 2012 | Q4 2011 | Q3 2011 | Q2 2011 | Q1 2011 | Q4 2010 |
|---|---|---|---|---|---|---|---|---|---|
| **Production Volumes** | | | | | | | | | |
| Crude Oil and NGLs (bbls/d) | 177,646 | 171,350 | 155,566 | 156,850 | 144,273 | 133,496 | 121,762 | 137,355 | 129,593 |
| Natural Gas (MMcf/d) | 566 | 577 | 596 | 636 | 660 | 656 | 654 | 652 | 688 |
| **Revenues** | 3,724 | 4,340 | 4,214 | 4,564 | 4,329 | 3,858 | 4,009 | 3,500 | 3,363 |
| **Operating Cash Flow** [1] | 963 | 1,310 | 1,078 | 1,085 | 1,019 | 945 | 1,064 | 834 | 815 |
| **Cash Flow** [1] | 697 | 1,117 | 925 | 904 | 851 | 793 | 939 | 693 | 645 |
| per Share – Diluted | 0.92 | 1.47 | 1.22 | 1.19 | 1.12 | 1.05 | 1.24 | 0.91 | 0.85 |
| **Operating Earnings (Loss)** [1] | (189) | 432 | 283 | 340 | 332 | 303 | 395 | 209 | 147 |
| per Share – Diluted | (0.25) | 0.57 | 0.37 | 0.45 | 0.44 | 0.40 | 0.52 | 0.28 | 0.19 |
| **Net Earnings (Loss)** | (118) | 289 | 396 | 426 | 266 | 510 | 655 | 47 | 78 |
| per Share – Basic | (0.16) | 0.38 | 0.52 | 0.56 | 0.35 | 0.68 | 0.87 | 0.06 | 0.10 |
| per Share – Diluted | (0.16) | 0.38 | 0.52 | 0.56 | 0.35 | 0.67 | 0.86 | 0.06 | 0.10 |
| **Capital Investment** [2] | 978 | 830 | 660 | 900 | 903 | 631 | 476 | 713 | 701 |
| **Cash Dividends** | 167 | 166 | 166 | 166 | 151 | 150 | 151 | 151 | 151 |
| per Share | 0.22 | 0.22 | 0.22 | 0.22 | 0.20 | 0.20 | 0.20 | 0.20 | 0.20 |

*(1) Non-GAAP measures defined in the Financial Results section of this MD&A.*
*(2) Includes expenditures on PP&E and E&E assets.*

### Fourth Quarter 2012 Results of Operations

In the fourth quarter, our financial results were negatively impacted by lower crude oil and natural gas prices, with significant decreases in crude oil benchmark prices in the month of December. The average WTI-WCS differential in December was US$30.37 per barrel as compared to US$11.72 per barrel for the same period last year. The fourth quarter was also impacted by a $393 million goodwill impairment charge, resulting primarily from the decline in future natural gas and crude oil prices and increased operating costs at our Suffield property within our Conventional segment. In addition, low refinery utilization as a result of planned turnaround activities, negatively impacted our financial results.

Realized price decreases were partially offset by crude oil and NGLs production increases of 23 percent, with the most significant increase at Christina Lake mainly due to phase C reaching full production capacity in the second quarter of 2012 and the start of production at phase D in the third quarter of 2012. In 2012, we achieved a new single day production high of 93,936 gross barrels at Christina Lake. At Narrows Lake we received final partner approval for the first phase.

Natural gas production in the fourth quarter of 2012 was 566 MMcf per day, a decrease of 14 percent from 2011, mainly due to expected declines in production from limited capital investment.



Table of Contents

### Fourth Quarter 2012 Financial Results

#### *Operating Cash Flow*

Operating cash flow decreased $56 million in the fourth quarter of 2012, as compared to the same period in 2011, primarily due to:
- A decrease of $116 million in Refining and Marketing operating cash flow due to lower refinery utilization during planned turnarounds and higher operating costs related to those activities; and
- A 25 percent decrease in our average sales price of crude oil and NGLs to $60.13 per barrel, caused mainly by the increase in benchmark price differentials.

Partially offset by:
- Crude oil and NGLs sales volumes increasing 31 percent, primarily resulting from an increase in production volumes at Christina Lake;
- Realized risk management gains before tax, excluding Refining and Marketing, of $102 million compared to gains of $29 million in 2011; and
- A decrease in crude oil and NGLs royalties of 48 percent due mainly to an increase in capital investments.

#### *Cash Flow*

Our cash flow decreased $154 million in the fourth quarter of 2012 primarily due to decreases in operating cash flow as discussed above; and
- An increase in current tax expense, excluding tax on divestitures, of $74 million in the fourth quarter of 2012 primarily due to withholding tax on U.S. dividends.

#### *Operating Earnings*

Our operating earnings decreased $521 million in the fourth quarter of 2012 primarily due to:
- Goodwill impairment of $393 million in our Conventional segment, resulting primarily from declining future natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production has exceeded reserve replacement in the area. With the lower future cash flows and decreasing volumes, the carrying amount of the goodwill, exceeded its fair value;
- Decreased cash flow as discussed above; and
- Increased DD&A as a result of higher production and higher DD&A rates.

Partially offset by:
- A decrease in deferred income tax, excluding deferred tax on gains and losses on unrealized risk management, non-operating foreign exchange and divestitures of $20 million.

#### *Net Earnings*

In the fourth quarter of 2012, our net earnings decreased $384 million. The factors discussed above that decreased our operating earnings also impacted net earnings in addition to:
- No divestitures in 2012 as compared to an after-tax gain on divestiture of $89 million in the same period in 2011; and
- Unrealized foreign exchange losses in 2012 as compared to gains in 2011.

Partially offset by:
- Unrealized risk management gains, after-tax, of $87 million as compared to losses of $180 million in the fourth quarter of 2011.

***Capital Investment***

Capital investment in the fourth quarter of 2012 was $978 million, an increase of $75 million from the same period in 2011. The fourth quarter was busy with construction on three phases at Foster Creek, two phases at Christina Lake and our drilling and completions programs across the other areas.

## OIL AND GAS RESERVES AND RESOURCES

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 & 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 also evaluated 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to crude oil and natural gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets independently with Management and with each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to provide a recommendation on approval of the reserves and resources disclosure to the Board.



Table of Contents

Highlights in 2012 include:

- Proved bitumen reserves increased approximately 18 percent and proved plus probable reserves increased approximately 23 percent;
  - Regulatory approval for phases A, B and C, and partner approval for phase A of the Narrows Lake project added proved reserves of 222 million barrels and proved plus probable reserves of 359 million barrels, transitioning contingent resources to proved reserves;
  - Christina Lake added proved reserves of 41 million barrels while proved plus probable reserves increased by 42 million barrels. Increases at Christina Lake were a result of increasing well density through most of the project area and improving steam to oil ratio performance;
  - Foster Creek added proved reserves of 32 million barrels and proved plus probable reserves of 80 million barrels. Increases at Foster Creek were a result of improved recovery due to improving steam to oil ratio performance and more efficient drainage of bitumen in the steam chamber;
- Heavy oil proved reserves increased approximately five percent and proved plus probable reserves increased approximately two percent. These increases were a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves increased by approximately three percent, as a result of expanding waterflood and carbon dioxide flood areas at Weyburn;
- Natural gas proved reserves declined approximately 21 percent and proved plus probable reserves declined approximately 19 percent as reduced extensions and technical revisions from lower capital investment did not offset production and dispositions. Also included in the decline, is a loss of 58 Bcf of gas reserves due to lower gas prices in the forecast causing some gas reserves to become uneconomic to produce;
- Economic bitumen best estimate contingent resources increased 1.4 billion barrels or approximately 17 percent. This increase is a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources, the recognition of SAGD feasibility in the Wabiskaw formation adjacent to Foster Creek and the recognition of contingent resources on the acquired land near Telephone Lake; and
- Bitumen best estimate prospective resources declined 1.5 billion barrels or approximately 15 percent, as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling and the sterilization of lands through approval of the Lower Athabasca Regional Plan ("LARP").

The reserves and resources data that follows is presented as at December 31, 2012 using McDaniel's January 1, 2013 forecast prices and costs and comparative information as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

**Reserves as at December 31**

| | Bitumen (MMbbls) | | Heavy Oil (MMbbls) | | Light & Medium Oil & NGLs (MMbbls) | | Natural Gas & CBM (Bcf) | |
|---|---|---|---|---|---|---|---|---|
| Before Royalties | **2012** | 2011 | **2012** | 2011 | **2012** | 2011 | **2012** | 2011 |
| Proved | **1,717** | 1,455 | **184** | 175 | **115** | 115 | **955** | 1,203 |
| Probable | **676** | 490 | **105** | 109 | **56** | 51 | **338** | 391 |
| **Proved plus Probable** | **2,393** | 1,945 | **289** | 284 | **171** | 166 | **1,293** | 1,594 |



Table of Contents

**Reconciliation of Proved Reserves**

| Before Royalties | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2011 | **1,455** | **175** | **115** | **1,203** |
| Extensions and Improved Recovery | **265** | **17** | **13** | **29** |
| Discoveries | **-** | **-** | **-** | **-** |
| Technical Revisions | **30** | **6** | **(2)** | **51** |
| Economic Factors | **-** | **-** | **-** | **(58)** |
| Acquisitions | **-** | **-** | **1** | **1** |
| Dispositions | **-** | **-** | **-** | **(59)** |
| Production | **(33)** | **(14)** | **(12)** | **(212)** |
| **December 31, 2012** | **1,717** | **184** | **115** | **955** |

| | | | | |
|---|---|---|---|---|
| Year Over Year Change | 262 | 9 | - | (248) |
| | 18% | 5% | 0% | (21)% |

### Reconciliation of Probable Reserves

| Before Royalties | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2011 | 490 | 109 | 51 | 391 |
| Extensions and Improved Recovery | 140 | 11 | 5 | 8 |
| Discoveries | - | - | - | - |
| Technical Revisions | 46 | (15) | - | (30) |
| Economic Factors | - | - | - | (4) |
| Acquisitions | - | - | - | - |
| Dispositions | - | - | - | (27) |
| Production | - | - | - | - |
| **December 31, 2012** | 676 | 105 | 56 | 338 |
| Year Over Year Change | 186 | (4) | 5 | (53) |
| | 38% | (4)% | 10% | (14)% |

### Economic Contingent and Prospective Resources as at December 31

| (billions of barrels, before royalties) | Bitumen 2012 | Bitumen 2011 |
|---|---|---|
| **Economic Contingent Resources** [1] | | |
| Low Estimate | 7.1 | 6.0 |
| Best Estimate | 9.6 | 8.2 |
| High Estimate | 12.8 | 10.8 |
| **Prospective Resources** [1][2] | | |
| Low Estimate | 5.0 | 5.7 |
| Best Estimate | 8.5 | 10.0 |
| High Estimate | 14.8 | 17.9 |

*(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and low, best and high estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.*

*(2) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective resources are not screened for economic viability.*

Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation 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 contingent resources do not include economic contingencies. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican.



Table of Contents

At Foster Creek and Christina Lake we have economic contingent resources located outside the currently approved development project areas. Regulatory approval of development project area expansion is necessary to enable the reclassification of these economic contingent resources as reserves. The rate at which we submit applications for development area expansion 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 have submitted an application for a development project at the Telephone Lake property which, if approved, would enable the reclassification of certain economic contingent resources in the area to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity in order to submit regulatory applications for development projects. Stratigraphic test well drilling and seismic activity is 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 development project approval at the Grand Rapids property. Provided all regulatory requirements are met, we anticipate receiving regulatory approval in 2013. Pilot project work is underway to examine optimal development strategies.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, approval of the Narrows Lake project resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic test well program in the Borealis Region moved some prospective resources to contingent resources. The overall reduction to prospective resources is the expected outcome of a successful stratigraphic test well 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.

Information with respect to pricing as well as additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resource estimates, is contained in our AIF for the year ended December 31, 2012.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions) | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Net Cash From (Used) In** | | | |
| Operating Activities | 3,420 | 3,273 | 2,591 |
| Investing Activities | (3,336) | (2,530) | (1,793) |
| **Net Cash Provided before Financing Activities** | 84 | 743 | 798 |
| Financing Activities | 592 | (558) | (631) |
| Foreign Exchange Gains (Losses) on Cash and Cash Equivalents Held in Foreign Currency | (11) | 10 | (22) |
| **Increase in Cash and Cash Equivalents** | 665 | 195 | 145 |

### Operating Activities

Cash from operating activities was $147 million higher in 2012 mainly due to the $367 million increase in cash flow, partially offset by the net change in non-cash working capital. Cash flow is discussed in the Financial Results section of this MD&A. Cash from operating activities is also impacted by the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $1,043 million at December 31, 2012 compared to $283 million at December 31, 2011. We anticipate that we will continue to meet our payment obligations as they come due.

### Investing Activities

Cash used for investing activities in 2012 was $806 million higher than 2011. The increase is primarily due to higher capital expenditures of $3.4 billion in 2012. Capital expenditures are further discussed under Net Capital Investment within the Financial Results section and Capital Investment within the Reportable Segments section of this MD&A.

### Financing Activities

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend and finally to growth capital. In 2012, we paid a dividend of $0.88 per share (2011 – $0.80 per share). Total dividend payments in 2012 were $665 million (2011 – $603 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.



Table of Contents

Cash from financing activities in 2012 increased $1.15 billion as a result of the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by increased dividends paid and the repayment of short-term borrowings throughout the year.

Our long-term debt was $4,679 million at December 31, 2012 with no payments of principal due until September 2014 (US$800 million). We had cash and cash equivalents of $1,160 million at December 31, 2012. Long-term debt and cash and cash equivalents increased with the issuance of senior unsecured notes in 2012.

#### *U.S. Senior Unsecured Notes*

On August 17, 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00 percent due August 15, 2022 (10 year) and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042 (30 year). The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

### Available Sources of Liquidity

| ($ millions) | Amount | Term |
|---|---|---|
| Cash and Cash Equivalents | **1,160** | Not applicable |
| Committed Credit Facility | **3,000** | November 2016 |
| Canadian Base Shelf Prospectus (1) | **1,500** | June 2014 |
| U.S. Base Shelf Prospectus (1) | **US$ 750** | July 2014 |

*(1) Availability is subject to market conditions.*

As at December 31, 2012, we are in compliance with all of the terms of our debt agreements.

#### *Committed Credit Facility*

In September 2012, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and reducing both the standby fees to maintain the facility as well as the cost of future borrowings. We also have a commercial paper program which, together with the committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding. As of December 31, 2012, no amounts were drawn on our committed credit facility and there was no commercial paper outstanding.

#### *Canadian Base Shelf Prospectus*

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

#### *U.S. Base Shelf Prospectus*

On June 6, 2012, we filed a U.S. base shelf prospectus for senior unsecured notes in the amount of US$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2012, US$750 million remains available under our U.S. base shelf prospectus. The U.S. base shelf prospectus expires in July 2014.

### Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairment, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Debt to Capitalization | **32%** | 27% | 29% |
| Debt to Adjusted EBITDA (times) | **1.1x** | 1.0x | 1.3x |



Table of Contents

Debt to Capitalization is calculated as follows:

| As at December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Debt | **4,679** | 3,527 | 3,432 |
| Shareholders' Equity | **9,806** | 9,406 | 8,395 |
| Capitalization | **14,485** | 12,933 | 11,827 |
| **Debt to Capitalization** | **32%** | 27% | 29% |

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

| As at December 31, | **2012** | 2011 | 2010 |
|---|---|---|---|
| **Debt** | **4,679** | 3,527 | 3,432 |
| **Net Earnings** | **993** | 1,478 | 1,081 |
| Add (Deduct): | | | |
| Finance Costs | **455** | 447 | 498 |
| Interest Income | **(109)** | (124) | (144) |
| Income Tax Expense | **783** | 729 | 223 |
| DD&A | **1,585** | 1,295 | 1,302 |
| Goodwill Impairment | **393** | - | - |
| Exploration Expense | **68** | - | - |
| Unrealized Gain on Risk Management | **(57)** | (180) | (46) |
| Foreign Exchange (Gain) Loss, net | **(20)** | 26 | (51) |
| (Gain) Loss on Divestiture of Assets | **-** | (107) | (116) |
| Other (Income) Loss, net | **(5)** | 4 | (13) |
| **Adjusted EBITDA** | **4,086** | 3,568 | 2,734 |
| **Debt to Adjusted EBITDA** | **1.1x** | 1.0x | 1.3x |

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At December 31, 2012, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

Our debt levels at December 31, 2012 were higher than at December 31, 2011 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter of 2012. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

### Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2012, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of Cenovus. Options issued by Cenovus prior to February 24, 2011, have associated tandem stock appreciation rights ("TSARs") and options issued after February 24, 2011 have associated net settlement rights ("NSRs").

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. DSUs vest immediately and are equivalent in value to a Cenovus common share on the date of redemption.

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSR's and PSU's are 1.42, 5.85 and 1.24 years, respectively. See the notes to the Consolidated Financial Statements for details of our stock-based compensation plans.



Table of Contents

#### *Total Outstanding Common Shares and Stock-Based Compensation Plans*

| (thousands of units) | **December 31, 2012** |
|---|---|
| **Common Shares** | **755,843** |
| **Stock Options** | |
| NSRs | **15,074** |
| TSARs | **11,251** |
| Cenovus Replacement TSARs | **5,229** |
| Encana Replacement TSARs | **7,722** |
| **Other Stock-Based Compensation Plans** | |
| PSUs | **5,258** |
| DSUs | **1,084** |

### Contractual Obligations and Commitments

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

| | Expected Payment Date | | | | | | |
|---|---|---|---|---|---|---|---|
| ($ millions) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018+ | Total |
| **Operating** | | | | | | | |
| Pipeline Transportation [1] | 145 | 209 | 378 | 403 | 675 | 8,130 | 9,940 |
| Operating Leases (Building Leases) | 109 | 106 | 112 | 110 | 104 | 1,602 | 2,143 |
| Product Purchases | 81 | 18 | 18 | 6 | - | - | 123 |
| Other Long-term Commitments | 32 | 25 | 18 | 7 | 6 | 10 | 98 |
| Interest on Long-term Debt | 254 | 252 | 216 | 216 | 216 | 3,120 | 4,274 |
| Interest on Partnership Contribution Payable | 100 | 76 | 51 | 25 | 2 | - | 254 |
| **Total Operating** | 721 | 686 | 793 | 767 | 1,003 | 12,862 | 16,832 |
| **Investing** | | | | | | | |
| Capital Commitments [2] | 320 | 54 | 61 | 53 | 6 | 2 | 496 |
| Other Long-term Commitments | 1 | - | - | - | - | - | 1 |
| Decommissioning Liabilities | 85 | 142 | 125 | 128 | 137 | 6,248 | 6,865 |
| **Total Investing** | 406 | 196 | 186 | 181 | 143 | 6,250 | 7,362 |
| **Financing** | | | | | | | |
| Long-term Debt | - | 796 | - | - | - | 3,930 | 4,726 |
| Partnership Contribution Payable | 386 | 410 | 435 | 462 | 120 | - | 1,813 |
| **Total Financing** | 386 | 1,206 | 435 | 462 | 120 | 3,930 | 6,539 |
| **Total Payments** [3] | 1,513 | 2,088 | 1,414 | 1,410 | 1,266 | 23,042 | 30,733 |
| Fixed Price Product Sales | 50 | 52 | 54 | 55 | 3 | - | 214 |
| Partnership Contribution Receivable | 471 | 471 | 471 | 471 | 118 | - | 2,002 |

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

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), debt, future building leases, marketing agreements and capital commitments. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information please see the notes to the Consolidated Financial Statements.

As at December 31, 2012, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 49 Bcf of natural gas at a weighted average price of $4.38 per Mcf.

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

### Legal Proceedings

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



Table of Contents

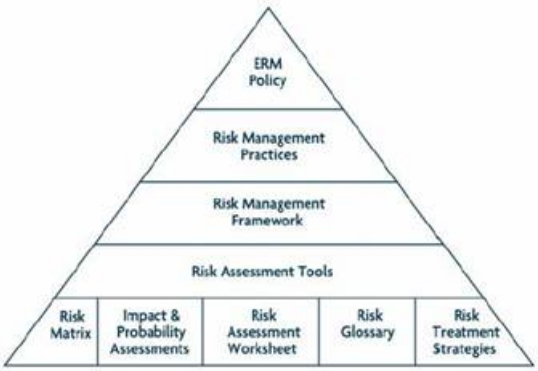
## RISK MANAGEMENT

The Canadian Institute of Chartered Accountants issued new guidance in 2012, which suggested that corporate reporting would be enhanced with further disclosures of how companies approach and mitigate risks generally. Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others that are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk within our risk appetite ultimately determined by Management and confirmed by the Board.

### Risk Governance

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

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




### Risk Assessment

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

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

Management determines if additional risk treatment is required based on the residual risk ranking and there are prescribed actions for elevating these exposures to the right decision makers.

### Risk Management Roles and Responsibilities

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

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

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

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

### Principal and Strategic Risks

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

Principal and strategic risks are categorized into:

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

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2012.

The following is a discussion of how some of the material principal and strategic risks impact our business:

### *Financial Risk*

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit is managed through our Board approved credit policy.

#### Commodity Price Risk

Fluctuations in future commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints and alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

Changes in future commodity prices will affect the revenue generated by the sale of our crude oil, NGLs, natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

We anticipate commodity prices and refining margins will continue to be volatile over the next few years. If crude oil and natural gas prices decline significantly and remained at low levels for an extended period of time, the carrying value of our assets may be subject to impairment, future capital programs could be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations.

We manage our commodity price exposure through a combination of activities including integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations.

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

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

The details of these financial instruments as at December 31, 2012 are disclosed in the notes to the Consolidated Financial Statements. The financial impact is summarized below:

*Financial Impact of Risk Management Activities*

| | 2012 | | | 2011 | | |
|---|---|---|---|---|---|---|
| ($ millions) | Realized | Unrealized | Total | Realized | Unrealized | Total |
| Crude Oil and NGLs | 81 | 247 | 328 | (135) | 106 | (29) |
| Natural Gas | 247 | (176) | 71 | 210 | 38 | 248 |
| Refining | 7 | 1 | 8 | (14) | 7 | (7) |
| Power | 1 | (15) | (14) | 7 | 29 | 36 |
| Gains (Losses) on Risk Management | 336 | 57 | 393 | 68 | 180 | 248 |
| Income Tax Expense | 86 | 14 | 100 | 17 | 46 | 63 |
| Gains (Losses) on Risk Management, after-tax | 250 | 43 | 293 | 51 | 134 | 185 |





In 2012, our strategy to manage commodity price risk resulted in realized gains on both crude oil and natural gas financial instruments as contract benchmark commodity prices settled below our contract prices. We recognized unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices and the widening of light/heavy differentials at the end of 2012 compared to our contract prices. Natural gas financial instruments incurred unrealized losses as a result of increasing forward natural gas commodity prices. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We recognize that on an integrated basis, we have a long position in refined products which has become more strongly correlated to Brent crude rather than WTI. To better align our corporate risk management program with this exposure, we converted all existing 2013 WTI crude oil financial instruments to Brent pricing during 2012. In addition, 17,000 barrels per day were executed through financial instruments at fixed Brent pricing, resulting in a total of 37,000 barrels per day locked into a weighted average Brent price of US$111.32 per barrel.

*Commodity Price Sensitivities – Risk Management Positions*

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) for the year impacting earnings before income tax on open risk management positions as at December 31, 2012 as follows:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10 per bbl applied to Brent & WTI hedges | (156) | 156 |
| Crude Oil Differential Price | ± US$5 per bbl applied to differential hedges tied to production | 111 | (111) |
| Natural Gas Commodity Price | ± $1 per mcf applied to NYMEX natural gas hedges | (55) | 55 |
| Natural Gas Basis Price | ± $0.10 per mcf applied to natural gas basis hedges | 1 | (1) |
| Power Commodity Price | ± $25 per MWHr applied to power hedge | 19 | (19) |

#### Liquidity Risk

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. In depressed economic times or due to unforeseen events, Cenovus's liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2012, we had cash and cash equivalents of $1.2 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$750 million in unused capacity under our U.S. base shelf prospectus, the availability of which are dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term from unforeseen economic events that could create further volatility in cash flow.

### *Operational Risk*

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

#### Safety Risk

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

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

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



Table of Contents

#### Transportation Restrictions

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

To help mitigate these risks, we employ a diversified sales strategy which includes sales at multiple market hubs to a variety of creditworthy counterparties utilizing multiple transportation options. In addition, we support and are prepared to commit to new and expanding transportation infrastructure with access to additional markets for our production, including cargo and railcar transportation methods.

We anticipate transportation constraints will continue in the near term. The Keystone XL project and the Northern Gateway Pipeline project, if approved, will benefit heavy oil producers. The Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Northern Gateway pipeline project in its current form will connect Alberta's oil sands to the western Canada coast, allowing for transportation to new markets, such as Asia. Other industry options are being developed and we are actively participating in those developments.

#### Capital Project Execution and Operating Risk

There are risks associated with the execution and operations of our upstream and refining projects. Over the next 10 years, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations and availability of skilled labour, key components or other scarce resources, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures.

Operational risks affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. Our operational risks include, but are not limited to safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, phased growth execution of oil sands projects and partner risks. We attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

#### Reserves Replacement Risk

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

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

To date our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our 10 year strategic plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2012.

#### Environmental Risk

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

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, and oversees compliance with 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.

#### *Regulatory Risk*

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

#### Environmental Regulation Risk

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

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

##### *Water Use Impacts*

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements under these licenses reduces the amount of water available for our use, our production could decline or operating costs could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

##### *Greenhouse Gases & Air Pollutants*

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

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating costs and reduce demand for crude oil, natural gas and certain refined products. Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. We incorporate the potential costs of carbon, ranging from $15-$65 per tonne of $CO_2$ into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

##### *Land Use, Habitat and Biodiversity*

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





policy resulting from the implementation of a regional plan. On August 22, 2012, the Government of Alberta approved its LARP, which was issued under the ALSA, and came into effect on September 1, 2012.

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. Some of our Oil Sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted limiting the pace of development due to environmental limits and thresholds. The areas identified have no direct impact on our strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications.

## CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

### Critical Accounting Judgments in Applying Accounting Policies

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

#### *Exploration and Evaluation Assets*

The application of Cenovus's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is no longer technically feasible or commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

#### *Identification of CGUs*

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

### Key Sources of Estimation Uncertainty

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

#### *Reserves*

There are a number of inherent uncertainties associated with estimating reserves. Reserve estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserve estimates which would have a significant impact on the impairment test and depreciation, depletion and amortization expense of Cenovus's crude oil and natural gas assets. Cenovus's crude oil and natural gas reserves are evaluated and reported to us by independent qualified reserves evaluators.



Table of Contents

#### *Impairment of Assets*

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

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

At December 31, 2012, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs to sell. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

### Oil and Natural Gas Prices

The future prices used to determine cash flows from oil and gas reserves are as follows:

| | 2013 | 2014 | 2015 | 2016 | 2017 | Average Annual Percent Change to 2024 |
|---|---|---|---|---|---|---|
| WTI (US$/barrel) | 92.50 | 92.50 | 93.60 | 95.50 | 97.40 | 2% |
| AECO ($/Mcf) | 3.35 | 3.85 | 4.35 | 4.70 | 5.10 | 3% |

### Discount Rate

Evaluations of discounted future cash flow generally use, as a starting point, the discount rate of 10 percent which is an industry standard rate used by independent qualified reserve evaluators in preparing their reserve reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

#### *Decommissioning Costs*

Provisions are recognized for the future decommissioning and restoration of Cenovus's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. During the year ended December 31, 2012, the decommissioning liability increased $417 million as a result of changes in the discount rate, the timing of settlement and the estimated costs that will arise on settlement. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

#### *Income Tax Provisions*

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

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

### Changes in Accounting Policies and Future Accounting Pronouncements

During the year ended December 31, 2012, Cenovus did not adopt any new accounting policies.

The following summarizes the future accounting pronouncements that will impact Cenovus. We will adopt each of the following accounting pronouncements on the effective date. Unless otherwise stated below, the impact of the initial application of the standards listed was not known or reasonably estimable at the time of authorization of the Consolidated Financial Statements.

***Joint Arrangements, Consolidation, Associates and Disclosures***

In May 2011, the International Accounting Standards Board ("IASB") issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control to include three elements: (1) power over an investee, (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.
- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". Under IFRS 11, a joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.
- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31 and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities.
- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10, but retains the current guidance for separate financial statements.
- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. It is anticipated that the application of these five standards will not have a significant impact on the Consolidated Financial Statements.

Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of Cenovus's accounting policy under IFRS 11 requires judgment in determining the classification of its joint arrangements. It was determined that Cenovus has rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements will be classified as joint operations under IFRS 11 and Cenovus's share of the assets, liabilities, revenues and expenses will be recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, Cenovus considered the following:

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





***Employee Benefits***

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendments require the recognition of changes in defined benefit obligations and fair value of plan assets when they occur, eliminating the 'corridor approach', and accelerates the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are to be recognized immediately through Other Comprehensive Income ("OCI"). In addition, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendments also enhance financial statement disclosures.

The amendments to IAS 19 require retrospective application. Based on Cenovus's preliminary assessment, when the amendments are applied for the first time for the year ending December 31, 2013, net earnings for the year ended December 31, 2012 would increase $1 million and other comprehensive income after tax would decrease by $3 million (2011 – $nil and decrease $12 million, respectively). Shareholders' equity as at December 31, 2012 would decrease $24 million (January 1, 2012 – decrease $22 million) with corresponding adjustments being recognized in other liabilities and deferred income tax liability.

***Fair Value Measurement***

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. IFRS 13 will not have a significant impact on the Consolidated Financial Statements.

***Financial Instruments***

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities,

although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. Cenovus is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

***Presentation of Items of Other Comprehensive Income***

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The adoption of this amendment will not have a significant impact on the Consolidated Financial Statements.

***Offsetting Financial Assets and Financial Liabilities***

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures"* ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar arrangements.
- IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. It is anticipated that IFRS 7 and IAS 32 will not have significant impacts on the Consolidated Financial Statements.



Table of Contents

## CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2012. Based on their evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2012.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2012.

There have been no changes to ICFR during the year ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

## TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

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

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 not 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.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. Our Corporate Responsibility Report can be found on our website at www.cenovus.com. This report was aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

In September 2012, we were named to the Dow Jones Sustainability World Index ("DJSI World") for the first time and to the Dow Jones Sustainability North America Index for the third year in a row. We were the only Canadian integrated oil and gas company listed to the DJSI World in 2012. DJSI World recognizes the top 10 percent of the 2,500 largest companies in the Dow Jones Global Total Stock Market Index that lead the field in terms of corporate responsibility performance. In October 2012, for the third year in a row, Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2012 Carbon Disclosure Leadership Index for Canada. In January 2013, we were named for the first time to the Corporate Knights Global 100 list for 2013, which recognizes the world's most sustainable corporations.



Table of Contents

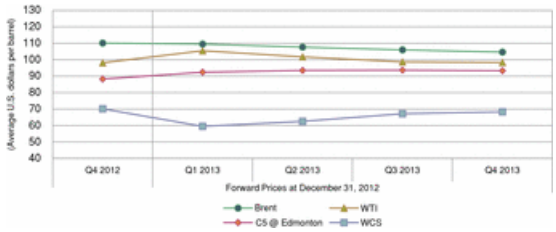
## OUTLOOK

We continue to move forward on our 10 year strategic plan targeting oil sands bitumen production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Grand Rapids and Telephone Lake. We will continue the development of our oil sands resources in multiple phases using a low

cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

### Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

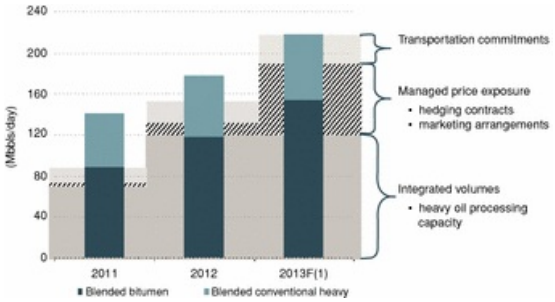



- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. Short-term prices are likely to remain volatile and be impacted by market expectations;
- Brent-WTI differentials are expected to narrow over the first half of 2013 as new pipeline capacity is added to move crude oil from Cushing to U.S. Gulf Coast markets;
- WCS prices should weaken relative to U.S. Gulf Coast pricing as inland crude oil supply continues to grow at a faster pace than rail and pipeline takeaway capacity. Although all WCSB crude oil should show downward price pressure, heavy grades should perform somewhat better in the latter half of 2013 once new coking capacity is added in the U.S. Midwest;
- Refining crack margins are projected to soften in 2013 when new pipeline capacity out of Cushing should cause WTI crude oil discounts to moderate. Refiners processing WCSB crude oil should continue to see strong margins; and
- Natural gas prices should continue to firm, provided weather remains near historic norms, as supply growth moderates with reduced activity and demand growth continues due to still very competitive North American gas pricing.

While we expect to see volatility in crude prices we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products which are closely tied to Brent pricing;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude prices by entering into physical supply transactions with fixed price components directly with refiners; and

***Protection Against Canadian Congestion***




*(1) Expected gross production capacity*

- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

### Key Priorities for 2013

#### *Market Access*

We are focused on near and mid-term strategies to broaden market access for Canadian oil. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. This will include increasing our rail shipping




Table of Contents


capacity for oil to approximately 10,000 barrels per day, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil.

#### *Attacking Cost Structures*

We have a track record of cost efficiency. To continue to meet our business plan, we must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we have a number of opportunities to improve our cost efficiency by further leveraging our supply chain management to improve capital and operating costs.

#### *Other Key Challenges*

We will need to effectively manage our business to support our development plans including timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A. We also direct our shareholders to review the guidance for 2013 that we publish on our website, www.cenovus.com, in connection with our December 2012 news release.

### Capital Allocation in the Future

We will continue to develop our strategy with respect to capital investment and returns to shareholders. We believe that strong operational performance will translate into solid financial performance. Future cash flow will continue to be allocated using a disciplined approached, focusing on the following priorities:

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

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow.

Future dividends are at the sole discretion of the Board and considered quarterly.

## ADVISORY

### Forward-Looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "target", "project", "could", "focus", "vision", "goal", "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 or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology and projected 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 and others that apply to the industry generally.

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

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



Table of Contents

risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; 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; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2012, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

### Oil and Gas Information

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2012 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. The estimates were made in accordance with the Canadian Oil and Gas Evaluation Handbook and comply with the requirements of NI 51-101.

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

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2012 reserves evaluation, which comply with NI 51-101 requirements.

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

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

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 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



Table of Contents

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 estimates for the individual projects.

Additional information relating to our oil and gas reserves and resources is presented in our AIF and Form 40-F for the year ended December 31, 2012, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

## ABBREVIATIONS

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

| Crude Oil and NGLs | | Natural Gas | |
|---|---|---|---|
| bbl | barrel | Mcf | thousand cubic feet |
| bbls/d | barrels per day | MMcf | million cubic feet |
| Mbbls/d | thousand barrels per day | Bcf | billion cubic feet |
| MMbbls | million barrels | MMBtu | million British thermal units |
| | | GJ | Gigajoule |
| | | CBM | Coal Bed Methane |

TM Trademark of Cenovus Energy Inc.



Table of Contents

# Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2012

(Canadian Dollars)

Table of Contents

## Report of Management

***Management's Responsibility for the Consolidated Financial Statements***

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes — Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

***Management's Assessment of Internal Control over Financial Reporting***

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

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

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2012. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control — Integrated Framework to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2012.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2012, as stated in their Auditor's Report dated February 13, 2013. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Brian C. Ferguson

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

/s/ Ivor M. Ruste

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

**February 13, 2013**



Table of Contents

# Independent Auditor's Report

***To the Shareholders of Cenovus Energy Inc.***

We have completed an integrated audit of Cenovus Energy Inc.'s 2012 and 2011 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2012 and an audit of its 2010 Consolidated Financial Statements. Our opinions, based on our audits, are presented below.

***Report on the Consolidated Financial Statements***

We have audited the accompanying Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2012 and December 31, 2011 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years in the period ended December 31, 2012, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

***Management's Responsibility for the Consolidated Financial Statements***

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

***Auditor's Responsibility***

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

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

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

***Opinion***

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of Cenovus Energy Inc. as at December 31, 2012 and December 31, 2011 and its financial performance and cash flows for each of the three years in the period ended December 31, 2012 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

***Report on Internal Control over Financial Reporting***

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2012, based on criteria established in Internal Control – Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

***Management's Responsibility for Internal Control over Financial Reporting***

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management.



Table of Contents

***Auditor's Responsibility***

Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

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

### *Definition of Internal Control over Financial Reporting*

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

### *Inherent Limitations*

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

### *Opinion*

In our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2012 based on criteria established in Internal Control – Integrated Framework, issued by COSO.

/s/ PricewaterhouseCoopers LLP
**PricewaterhouseCoopers LLP**
Chartered Accountants
Calgary, Alberta, Canada

**February 13, 2013**



Table of Contents

# CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

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

| | Notes | 2012 | 2011 | 2010 |
|---|---|---|---|---|
| **Revenues** | 1 | | | |
| Gross Sales | | 17,229 | 16,185 | 13,090 |
| Less: Royalties | | 387 | 489 | 449 |
| | | 16,842 | 15,696 | 12,641 |
| **Expenses** | 1 | | | |
| Purchased Product | | 9,223 | 9,090 | 7,551 |
| Transportation and Blending | | 1,798 | 1,369 | 1,065 |
| Operating | | 1,682 | 1,406 | 1,286 |
| Production and Mineral Taxes | | 37 | 36 | 34 |
| (Gain) Loss on Risk Management | 31 | (393) | (248) | (324) |
| Depreciation, Depletion and Amortization | 16 | 1,585 | 1,295 | 1,302 |
| Goodwill Impairment | 19 | 393 | - | - |
| Exploration Expense | 15 | 68 | - | 3 |
| General and Administrative | | 352 | 295 | 246 |
| Finance Costs | 5 | 455 | 447 | 498 |
| Interest Income | 6 | (109) | (124) | (144) |
| Foreign Exchange (Gain) Loss, net | 7 | (20) | 26 | (51) |
| (Gain) Loss on Divestiture of Assets | 17 | - | (107) | (116) |
| Other (Income) Loss, net | | (5) | 4 | (13) |
| **Earnings Before Income Tax** | | 1,776 | 2,207 | 1,304 |
| Income Tax Expense | 8 | 783 | 729 | 223 |
| **Net Earnings** | | 993 | 1,478 | 1,081 |
| **Other Comprehensive Income (Loss), Net of Tax** | | | | |
| Foreign Currency Translation Adjustment | | (24) | 48 | 71 |
| **Comprehensive Income** | | 969 | 1,526 | 1,152 |
| **Net Earnings per Common Share** | 9 | | | |
| Basic | | $ 1.31 | $ 1.96 | $ 1.44 |
| Diluted | | $ 1.31 | $ 1.95 | $ 1.43 |

*See accompanying Notes to Consolidated Financial Statements.*



Table of Contents

# CONSOLIDATED BALANCE SHEETS

**As at December 31,**
**($ millions)**

| | Notes | 2012 | 2011 |
|---|---|---|---|
| **Assets** | | | |
| **Current Assets** | | | |
| Cash and Cash Equivalents | 10 | **1,160** | 495 |
| Accounts Receivable and Accrued Revenues | 11 | **1,464** | 1,405 |
| Current Portion of Partnership Contribution Receivable | 12 | **384** | 372 |
| Inventories | 13 | **1,288** | 1,291 |
| Risk Management | 31 | **283** | 232 |
| Assets Held for Sale | 14 | **-** | 116 |
| **Current Assets** | | **4,579** | 3,911 |
| Exploration and Evaluation Assets | 1,15 | **1,285** | 880 |
| Property, Plant and Equipment, net | 1,16 | **16,152** | 14,324 |
| Partnership Contribution Receivable | 12 | **1,398** | 1,822 |
| Risk Management | 31 | **5** | 52 |
| Income Tax Receivable | | **-** | 29 |
| Other Assets | 18 | **58** | 44 |
| Goodwill | 1,19 | **739** | 1,132 |
| **Total Assets** | | **24,216** | 22,194 |
| **Liabilities and Shareholders' Equity** | | | |
| **Current Liabilities** | | | |
| Accounts Payable and Accrued Liabilities | 20 | **2,650** | 2,579 |
| Income Tax Payable | | **217** | 329 |
| Current Portion of Partnership Contribution Payable | 12 | **386** | 372 |
| Risk Management | 31 | **17** | 54 |
| Liabilities Related to Assets Held for Sale | 14 | **-** | 54 |
| **Current Liabilities** | | **3,270** | 3,388 |
| Long-Term Debt | 21 | **4,679** | 3,527 |
| Partnership Contribution Payable | 12 | **1,426** | 1,853 |
| Risk Management | 31 | **1** | 14 |
| Decommissioning Liabilities | 22 | **2,315** | 1,777 |
| Other Liabilities | 23 | **151** | 128 |
| Deferred Income Taxes | 8 | **2,568** | 2,101 |
| **Total Liabilities** | | **14,410** | 12,788 |
| Shareholders' Equity | | **9,806** | 9,406 |
| **Total Liabilities and Shareholders' Equity** | | **24,216** | 22,194 |
| Commitments and Contingencies | 33 | | |

*See accompanying Notes to Consolidated Financial Statements.*

Approved by the Board of Directors

/s/ Michael A. Grandin
**Michael A. Grandin**
Director
Cenovus Energy Inc.

/s/ Colin Taylor
**Colin Taylor**
Director
Cenovus Energy Inc.



Table of Contents

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

**($ millions)**

| | Share Capital (Note 25) | Paid in Surplus (Note 25) | Retained Earnings | AOCI [1] | Total |
|---|---|---|---|---|---|
| **Balance as at January 1, 2010** | 3,681 | 4,083 | 45 | - | 7,809 |
| Net Earnings | - | - | 1,081 | - | 1,081 |
| Other Comprehensive Income (Loss) | - | - | - | 71 | 71 |
| Total Comprehensive Income for the Year | - | - | 1,081 | 71 | 1,152 |
| Common Shares Issued Under Option Plans | 35 | - | - | - | 35 |
| Dividends on Common Shares | - | - | (601) | - | (601) |
| **Balance as at December 31, 2010** | 3,716 | 4,083 | 525 | 71 | 8,395 |
| Net Earnings | - | - | 1,478 | - | 1,478 |
| Other Comprehensive Income (Loss) | - | - | - | 48 | 48 |
| Total Comprehensive Income for the Year | - | - | 1,478 | 48 | 1,526 |
| Common Shares Issued Under Option Plans | 64 | - | - | - | 64 |
| Stock-Based Compensation Expense | - | 24 | - | - | 24 |
| Dividends on Common Shares | - | - | (603) | - | (603) |
| **Balance as at December 31, 2011** | 3,780 | 4,107 | 1,400 | 119 | 9,406 |
| Net Earnings | - | - | 993 | - | 993 |
| Other Comprehensive Income (Loss) | - | - | - | (24) | (24) |
| Total Comprehensive Income for the Year | - | - | 993 | (24) | 969 |
| Common Shares Issued Under Option Plans | 49 | - | - | - | 49 |
| Stock-Based Compensation Expense | - | 47 | - | - | 47 |
| Dividends on Common Shares | - | - | (665) | - | (665) |

| | | | | | |
|---|---|---|---|---|---|
| **Balance as at December 31, 2012** | **3,829** | **4,154** | **1,728** | **95** | **9,806** |

*(1) Accumulated Other Comprehensive Income.*

*See accompanying Notes to Consolidated Financial Statements.*



Table of Contents

# CONSOLIDATED STATEMENTS OF CASH FLOWS

**For the years ended December 31,**
**($ millions)**

| | Notes | 2012 | 2011 | 2010 |
|---|---|---|---|---|
| **Operating Activities** | | | | |
| Net Earnings | | **993** | 1,478 | 1,081 |
| Depreciation, Depletion and Amortization | | **1,585** | 1,295 | 1,302 |
| Goodwill Impairment | | **393** | - | - |
| Exploration Expense | | **68** | - | - |
| Deferred Income Taxes | 8 | **474** | 575 | 141 |
| Cash Tax on Divestiture of Assets | | **-** | 13 | - |
| Unrealized (Gain) Loss on Risk Management | 31 | **(57)** | (180) | (46) |
| Unrealized Foreign Exchange (Gain) Loss | 7 | **(70)** | (42) | (69) |
| (Gain) Loss on Divestiture of Assets | 17 | **-** | (107) | (116) |
| Unwinding of Discount on Decommissioning Liabilities | 5,22 | **86** | 75 | 75 |
| Other | | **171** | 169 | 44 |
| | | **3,643** | 3,276 | 2,412 |
| Net Change in Other Assets and Liabilities | | **(113)** | (82) | (55) |
| Net Change in Non-Cash Working Capital | | **(110)** | 79 | 234 |
| **Cash From Operating Activities** | | **3,420** | 3,273 | 2,591 |
| **Investing Activities** | | | | |
| Capital Expenditures – Exploration and Evaluation Assets | 15 | **(654)** | (527) | (350) |
| Capital Expenditures – Property, Plant and Equipment | 16 | **(2,795)** | (2,265) | (1,851) |
| Proceeds From Divestiture of Assets | | **76** | 173 | 309 |
| Cash Tax on Divestiture of Assets | | **-** | (13) | - |
| Net Change in Investments and Other | | **(13)** | (28) | 4 |
| Net Change in Non-Cash Working Capital | | **50** | 130 | 95 |
| **Cash (Used in) Investing Activities** | | **(3,336)** | (2,530) | (1,793) |
| **Net Cash Provided (Used) before Financing Activities** | | **84** | 743 | 798 |
| **Financing Activities** | | | | |
| Net Issuance (Repayment) of Short-Term Borrowings | | **3** | (9) | - |
| Net Issuance (Repayment) of Revolving Long-Term Debt | | **-** | - | (58) |
| Issuance of Long-Term Debt | | **1,219** | - | - |
| Proceeds on Issuance of Common Shares | | **37** | 48 | 28 |
| Dividends Paid on Common Shares | 9 | **(665)** | (603) | (601) |
| Other | | **(2)** | 6 | - |
| **Cash From (Used in) Financing Activities** | | **592** | (558) | (631) |
| **Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency** | | **(11)** | 10 | (22) |
| **Increase (Decrease) in Cash and Cash Equivalents** | | **665** | 195 | 145 |
| **Cash and Cash Equivalents, Beginning of Year** | | **495** | 300 | 155 |
| **Cash and Cash Equivalents, End of Year** | | **1,160** | 495 | 300 |
| Supplementary Cash Flow Information | 32 | | | |

*See accompanying Notes to Consolidated Financial Statements.*



Table of Contents

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

### 1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

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

The Company's reportable segments are as follows:

- **Oil Sands,** includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the 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 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 tabular financial information which follows presents the segmented information first by segment, then by product and geographic location.



Table of Contents

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

### A) Results of Operations - Segment and Operational Information

| For the years ended December 31, | Oil Sands | | | Conventional | | | Refining and Marketing | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | 4,088 | 3,291 | 2,702 | 2,068 | 2,328 | 2,284 | 11,356 | 10,625 | 8,228 |
| Less: Royalties | 215 | 284 | 279 | 172 | 205 | 170 | - | - | - |
| | 3,873 | 3,007 | 2,423 | 1,896 | 2,123 | 2,114 | 11,356 | 10,625 | 8,228 |
| **Expenses** | | | | | | | | | |
| Purchased Product | - | - | - | - | - | - | 9,506 | 9,149 | 7,674 |
| Transportation and Blending | 1,653 | 1,231 | 935 | 145 | 138 | 130 | - | - | - |
| Operating | 584 | 438 | 367 | 513 | 488 | 434 | 587 | 481 | 488 |
| Production and Mineral Taxes | - | - | - | 37 | 36 | 34 | - | - | - |
| (Gain) Loss on Risk Management | (80) | 70 | (10) | (252) | (152) | (258) | (4) | 14 | (10) |
| **Operating Cash Flow** | 1,716 | 1,268 | 1,131 | 1,453 | 1,613 | 1,774 | 1,267 | 981 | 76 |
| Depreciation, Depletion and Amortization | 482 | 347 | 375 | 905 | 778 | 799 | 146 | 130 | 96 |
| Goodwill Impairment | - | - | - | 393 | - | - | - | - | - |
| Exploration Expense | - | - | 3 | 68 | - | - | - | - | - |
| **Segment Income (Loss)** | 1,234 | 921 | 753 | 87 | 835 | 975 | 1,121 | 851 | (20) |

| For the years ended December 31, | Corporate and Eliminations | | | Consolidated | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | |
| Gross Sales | (283) | (59) | (124) | 17,229 | 16,185 | 13,090 |
| Less: Royalties | - | - | - | 387 | 489 | 449 |
| | (283) | (59) | (124) | 16,842 | 15,696 | 12,641 |
| **Expenses** | | | | | | |
| Purchased Product | (283) | (59) | (123) | 9,223 | 9,090 | 7,551 |
| Transportation and Blending | - | - | - | 1,798 | 1,369 | 1,065 |
| Operating | (2) | (1) | (3) | 1,682 | 1,406 | 1,286 |
| Production and Mineral Taxes | - | - | - | 37 | 36 | 34 |
| (Gain) Loss on Risk Management | (57) | (180) | (46) | (393) | (248) | (324) |
| | 59 | 181 | 48 | 4,495 | 4,043 | 3,029 |
| Depreciation, Depletion and Amortization | 52 | 40 | 32 | 1,585 | 1,295 | 1,302 |
| Goodwill Impairment | - | - | - | 393 | - | - |
| Exploration Expense | - | - | - | 68 | - | 3 |
| **Segment Income (Loss)** | 7 | 141 | 16 | 2,449 | 2,748 | 1,724 |
| General and Administrative | 352 | 295 | 246 | 352 | 295 | 246 |
| Finance Costs | 455 | 447 | 498 | 455 | 447 | 498 |
| Interest Income | (109) | (124) | (144) | (109) | (124) | (144) |
| Foreign Exchange (Gain) Loss, net | (20) | 26 | (51) | (20) | 26 | (51) |
| (Gain) Loss on Divestiture of Assets | - | (107) | (116) | - | (107) | (116) |
| Other (Income) Loss, net | (5) | 4 | (13) | (5) | 4 | (13) |
| | 673 | 541 | 420 | 673 | 541 | 420 |
| **Earnings Before Income Tax** | | | | 1,776 | 2,207 | 1,304 |

| | | | |
|---|---|---|---|
| Income Tax Expense | 783 | 729 | 223 |
| **Net Earnings** | 993 | 1,478 | 1,081 |



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

## B) Financial Results by Upstream Product

| | Crude Oil and NGLs | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | 4,037 | 3,217 | 2,610 | 1,559 | 1,492 | 1,229 | 5,596 | 4,709 | 3,839 |
| Less: Royalties | 215 | 282 | 276 | 166 | 193 | 153 | 381 | 475 | 429 |
| | 3,822 | 2,935 | 2,334 | 1,393 | 1,299 | 1,076 | 5,215 | 4,234 | 3,410 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | 1,651 | 1,229 | 934 | 126 | 104 | 86 | 1,777 | 1,333 | 1,020 |
| Operating | 548 | 409 | 339 | 294 | 244 | 199 | 842 | 653 | 538 |
| Production and Mineral Taxes | - | - | - | 34 | 27 | 28 | 34 | 27 | 28 |
| (Gain) Loss on Risk Management | (62) | 87 | 14 | (23) | 43 | 5 | (85) | 130 | 19 |
| **Operating Cash Flow** | 1,685 | 1,210 | 1,047 | 962 | 881 | 758 | 2,647 | 2,091 | 1,805 |

| | Natural Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | 40 | 63 | 78 | 496 | 825 | 1,042 | 536 | 888 | 1,120 |
| Less: Royalties | - | 2 | 1 | 6 | 12 | 17 | 6 | 14 | 18 |
| | 40 | 61 | 77 | 490 | 813 | 1,025 | 530 | 874 | 1,102 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | 2 | 2 | 1 | 19 | 34 | 44 | 21 | 36 | 45 |
| Operating | 25 | 24 | 23 | 215 | 240 | 231 | 240 | 264 | 254 |
| Production and Mineral Taxes | - | - | - | 3 | 9 | 6 | 3 | 9 | 6 |
| (Gain) Loss on Risk Management | (18) | (17) | (24) | (229) | (195) | (263) | (247) | (212) | (287) |
| **Operating Cash Flow** | 31 | 52 | 77 | 482 | 725 | 1,007 | 513 | 777 | 1,084 |

| | Other | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | 11 | 11 | 14 | 13 | 11 | 13 | 24 | 22 | 27 |
| Less: Royalties | - | - | 2 | - | - | - | - | - | 2 |
| | 11 | 11 | 12 | 13 | 11 | 13 | 24 | 22 | 25 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | - | - | - | - | - | - | - | - | - |
| Operating | 11 | 5 | 5 | 4 | 4 | 4 | 15 | 9 | 9 |
| Production and Mineral Taxes | - | - | - | - | - | - | - | - | - |
| (Gain) Loss on Risk Management | - | - | - | - | - | - | - | - | - |
| **Operating Cash Flow** | - | 6 | 7 | 9 | 7 | 9 | 9 | 13 | 16 |

| | Total Upstream | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | 4,088 | 3,291 | 2,702 | 2,068 | 2,328 | 2,284 | 6,156 | 5,619 | 4,986 |
| Less: Royalties | 215 | 284 | 279 | 172 | 205 | 170 | 387 | 489 | 449 |
| | 3,873 | 3,007 | 2,423 | 1,896 | 2,123 | 2,114 | 5,769 | 5,130 | 4,537 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | 1,653 | 1,231 | 935 | 145 | 138 | 130 | 1,798 | 1,369 | 1,065 |
| Operating | 584 | 438 | 367 | 513 | 488 | 434 | 1,097 | 926 | 801 |
| Production and Mineral Taxes | - | - | - | 37 | 36 | 34 | 37 | 36 | 34 |
| (Gain) Loss on Risk Management | (80) | 70 | (10) | (252) | (152) | (258) | (332) | (82) | (268) |
| **Operating Cash Flow** | 1,716 | 1,268 | 1,131 | 1,453 | 1,613 | 1,774 | 3,169 | 2,881 | 2,905 |



Table of Contents

### C) Geographic Information

| For the years ended December 31, | Canada | | | United States | | | Consolidated | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 | **2012** | 2011 | 2010 |
| **Revenues** | | | | | | | | | |
| Gross Sales | **8,069** | 7,513 | 6,466 | **9,160** | 8,672 | 6,624 | **17,229** | 16,185 | 13,090 |
| Less: Royalties | **387** | 489 | 449 | **-** | - | - | **387** | 489 | 449 |
| | **7,682** | 7,024 | 6,017 | **9,160** | 8,672 | 6,624 | **16,842** | 15,696 | 12,641 |
| **Expenses** | | | | | | | | | |
| Purchased Product | **1,884** | 1,867 | 1,456 | **7,339** | 7,223 | 6,095 | **9,223** | 9,090 | 7,551 |
| Transportation and Blending | **1,798** | 1,369 | 1,065 | **-** | - | - | **1,798** | 1,369 | 1,065 |
| Operating | **1,118** | 947 | 814 | **564** | 459 | 472 | **1,682** | 1,406 | 1,286 |
| Production and Mineral Taxes | **37** | 36 | 34 | **-** | - | - | **37** | 36 | 34 |
| (Gain) Loss on Risk Management | **(385)** | (255) | (322) | **(8)** | 7 | (2) | **(393)** | (248) | (324) |
| | **3,230** | 3,060 | 2,970 | **1,265** | 983 | 59 | **4,495** | 4,043 | 3,029 |
| Depreciation, Depletion and Amortization | **1,439** | 1,165 | 1,216 | **146** | 130 | 86 | **1,585** | 1,295 | 1,302 |
| Goodwill Impairment | **393** | - | - | **-** | - | - | **393** | - | - |
| Exploration Expense | **68** | - | 3 | **-** | - | - | **68** | - | 3 |
| **Segment Income (Loss)** | **1,330** | 1,895 | 1,751 | **1,119** | 853 | (27) | **2,449** | 2,748 | 1,724 |

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

#### *Export Sales*

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $671 million (2011 – $700 million; 2010 – $646 million).

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

#### *By Segment*

| As at December 31, | Exploration and Evaluation Assets | | Property, Plant and Equipment | |
|---|---|---|---|---|
| | **2012** | 2011 | **2012** | 2011 |
| Oil Sands | **1,110** | 741 | **7,764** | 6,224 |
| Conventional | **175** | 139 | **4,929** | 4,668 |
| Refining and Marketing | **-** | - | **3,088** | 3,200 |
| Corporate and Eliminations | **-** | - | **371** | 232 |
| **Consolidated** | **1,285** | 880 | **16,152** | 14,324 |

| As at December 31, | Goodwill | | Total Assets | |
|---|---|---|---|---|
| | **2012** | 2011 | **2012** | 2011 |
| Oil Sands | **739** | 739 | **11,972** | 10,524 |
| Conventional | **-** | 393 | **5,304** | 5,566 |
| Refining and Marketing | **-** | - | **5,018** | 4,927 |
| Corporate and Eliminations | **-** | - | **1,922** | 1,177 |
| **Consolidated** | **739** | 1,132 | **24,216** | 22,194 |



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

#### *By Geographic Region*

| As at December 31, | Exploration and Evaluation Assets | | Property, Plant and Equipment | |
|---|---|---|---|---|
| | **2012** | 2011 | **2012** | 2011 |
| Canada | **1,285** | 880 | **13,065** | 11,124 |
| United States | **-** | - | **3,087** | 3,200 |
| **Consolidated** | **1,285** | 880 | **16,152** | 14,324 |

| As at December 31, | Goodwill | | Total Assets | |
|---|---|---|---|---|
| | **2012** | 2011 | **2012** | 2011 |
| Canada | **739** | 1,132 | **19,744** | 17,536 |

| | | | | |
|---|---|---|---|---|
| United States | - | - | 4,472 | 4,658 |
| **Consolidated** | **739** | 1,132 | **24,216** | 22,194 |

### E) Capital Expenditures

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Capital** | | | |
| Oil Sands | **2,211** | 1,415 | 857 |
| Conventional | **848** | 788 | 526 |
| Refining and Marketing | **118** | 393 | 656 |
| Corporate | **191** | 127 | 76 |
| | **3,368** | 2,723 | 2,115 |
| **Acquisition Capital** | | | |
| Oil Sands [2] | **69** | 44 | 23 |
| Conventional | **45** | 25 | 25 |
| Refining and Marketing | **-** | - | 38 |
| Corporate | **-** | 2 | - |
| **Total**[1] | **3,482** | 2,794 | 2,201 |

*(1) Includes expenditures on property, plant and equipment and exploration & evaluation assets.*
*(2) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.*

#### *Major Customers*

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2012, Cenovus had three customers (2011 – two; 2010 – two) which individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $3,928 million, $3,300 million and $2,839 million, respectively (2011 – $7,324 million and $2,683 million; 2010 – $5,376 million and $2,295 million).

## 2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements of Cenovus were approved by the Board of Directors on February 13, 2013.



Table of Contents



## 3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has the power to govern the financial and operating policies. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Investments in jointly controlled partnerships and unincorporated joint operations carry on certain of Cenovus's development, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby Cenovus's proportionate share of revenues, expenses, assets and liabilities are included in the consolidated accounts.

### B) Segment Reporting

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

### C) Foreign Currency Translation

#### *Functional and Presentation Currency*

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation which continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

#### *Transactions and Balances*

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any

gains or losses are recorded in the Consolidated Statements of Earnings and Comprehensive Income.

**D) Revenue and Interest Income Recognition**

***Sales of Product***

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

***Interest Income***

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

**E) Transportation and Blending**

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is sold.



Table of Contents



**F) Production and Mineral Taxes**

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

**G) Exploration Expense**

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the field/project/area is not technically feasible or commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

**H) Employee Benefit Plans**

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component, and other post-employment benefit plans ("OPEB").

Accruals for obligations under the employee defined benefit pension plan and the related costs are recorded net of plan assets.

The cost of the defined benefit pension plan and other post-employment benefits is actuarially determined using the projected unit credit method based on length of service and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is calculated on a straight-line basis over a period covering the non-vested expected average remaining service lives of employees and recognized immediately for vested benefits covered by the plans.

Pension expense for the defined contribution pension is recorded as the benefits are earned.

**I) Income Taxes**

Income taxes comprise current and deferred taxes. Current and deferred income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized.

Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction.

Deferred income tax assets and liabilities are presented as non-current.

**J) Net Earnings per Share Amounts**

Basic net earnings per common share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

**K) Cash and Cash Equivalents**

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

**L) Inventories**

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused it no longer exist.

**M) Assets (Disposal Group) Held for Sale**

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

**N) Exploration and Evaluation ("E&E") Assets**

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired.

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

E&E costs are subject to regular technical, commercial and management review to confirm the continued intent to develop the resources. If a field/project/area is determined to no longer be technically feasible or commercially viable, and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense in the period in which the determination occurs.

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

**O) Property, Plant and Equipment**

***Development and Production Assets***

Development and production assets are stated at cost less accumulated depreciation, depletion, amortization and net impairment losses. Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of the crude oil and natural gas properties, as well as any E&E expenditures incurred in finding commercial reserves of crude oil or natural gas transferred from E&E assets. Capitalized costs include internal costs, decommissioning liabilities, and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For the purpose of this calculation, natural gas is converted to oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of development and production assets are recognized in net earnings.

***Other Upstream Assets***

Other upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

***Refining Assets***

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

The initial acquisition costs of refining property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs. Routine maintenance and repair costs are expensed in the period in which they are incurred.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

| | |
|---|---|
| Land Improvements and Buildings | 25 to 40 years |
| Office Equipment and Vehicles | 3 to 20 years |
| Refining Equipment | 5 to 35 years |

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted if appropriate.

***Other Assets***

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted, if appropriate. Assets under construction are not subject to depreciation until they are available for use. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

**P) Impairment**

***Non-Financial Assets***

Property, plant and equipment and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The recoverable amount is determined as the greater of an asset's or cash-generating unit's ("CGU") value-in-use ("VIU") and fair value less costs to sell ("FVLCTS"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or asset.

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

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

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

***Financial Assets***

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flow and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.





An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

**Q) Borrowing Costs**

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

**R) Government Grants**

Government grants are recognized at fair value when there is reasonable assurance that the grants will be received and the Company will comply with the conditions of the grant. Grants related to assets are recorded as a reduction of the asset's carrying value and are depreciated over the useful life of the asset. Grants related to income are treated as a reduction of the related expense in the Consolidated Statements of Earnings and Comprehensive Income.

**S) Leases**

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within property, plant and equipment.

**T) Business Combinations and Goodwill**

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

### U) Provisions

#### *General*

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

#### *Decommissioning Liabilities*

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities and refining facilities. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in property, plant and equipment is depreciated over the useful life of the related asset. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.



Table of Contents



### V) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

### W) Dividends

Dividends are accrued when declared by the Board of Directors.

### X) Stock-Based Compensation

Cenovus has a number of cash and stock-based compensation plans which include stock options with associated tandem stock appreciation rights, stock options with associated net settlement rights, performance share units and deferred share units.

#### *Tandem Stock Appreciation Rights*

Stock options with associated tandem stock appreciation rights (“TSARs”) are accounted for as liability instruments which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

#### *Net Settlement Rights*

Stock options with associated net settlement rights (“NSRs”) are accounted for as equity instruments which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as compensation costs over the vesting period of the options, with a corresponding increase recorded as paid in surplus in Shareholders’ Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

#### *Performance and Deferred Share Units*

Performance share units (“PSUs”) and deferred share units (“DSUs”) are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus’s common shares at each period end. The fair value is recognized as compensation costs over the vesting period. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

### Y) Financial Instruments

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings and Comprehensive Income.

Financial instruments are classified as either “fair value through profit and loss”, “loans and receivables”, “held-to-maturity investments”, “available for sale financial assets” or “financial liabilities measured at amortized cost”. The Company determines the classification of its financial assets at initial recognition. Financial instruments are initially measured at fair value except in the case of “financial liabilities measured at amortized cost” which are initially measured at fair value net of directly attributable transaction costs.

The Company’s consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivable, the Partnership Contribution Receivable, risk management assets and long-term receivables. The Company’s financial liabilities include accounts payable and accrued liabilities, partner

loans payable, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

***Fair Value through Profit or Loss***

Financial assets and financial liabilities at “fair value through profit or loss” are either “held-for-trading” or have been “designated at fair value through profit or loss”. In both cases the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.



Table of Contents



Risk management assets and liabilities are derivative financial instruments classified as “held-for-trading” unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

***Loans and Receivables***

“Loans and receivables” are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. “Loans and receivables” comprise cash and cash equivalents, accounts receivable and accrued revenue, partner loans receivable, the Partnership Contribution Receivable and long-term receivables. Gains and losses on “loans and receivables” are recognized in net earnings when the “loans and receivables” are derecognized or impaired.

***Held to Maturity Investments***

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

***Available for Sale Financial Assets***

“Available for sale financial assets” are measured at fair value, with changes in the fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost.

***Financial Liabilities Measured at Amortized Cost***

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

**Z) Reclassification**

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2012.

**AA) Recent Accounting Pronouncements**

***New and Amended Standards Adopted***

The Company did not adopt any new standards, amendments or interpretations effective during the year ended December 31, 2012.

***New Standards and Interpretations not Yet Adopted***

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning after January 1, 2012, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2012. The standards and interpretations applicable to the Company are as follows and will be adopted on their respective effective date:



Table of Contents



**Joint Arrangements, Consolidation, Associates and Disclosures**

In May 2011, the IASB issued the following new and amended standards:

- IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") replaces IAS 27, "*Consolidated and Separate Financial Statements*" ("IAS 27") and Standing Interpretations Committee ("SIC") 12, "*Consolidation – Special Purpose Entities*". IFRS 10 revises the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.

- IFRS 11, "*Joint Arrangements*" ("IFRS 11") replaces IAS 31, "*Interest in Joint Ventures*" ("IAS 31") and SIC 13, "*Jointly Controlled Entities – Non-Monetary Contributions by Venturers*". Under IFRS 11, a joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method.

- IFRS 12, "*Disclosure of Interest in Other Entities*" ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and IAS 28, "*Investments in Associates*". It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities.

- IAS 27, "*Separate Financial Statements*" has been amended to conform to the changes made in IFRS 10, but retains the current guidance for separate financial statements.

- IAS 28, "*Investments in Associates and Joint Ventures*" has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013 and must be adopted concurrently. It is anticipated that the application of these five standards will not have a significant impact on the Consolidated Financial Statements.

Cenovus performed a comprehensive review of its interests in other entities and identified two individually significant interests, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of the Company's accounting policy under IFRS 11 requires judgment in determining the classification of its joint arrangements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements will be classified as joint operations under IFRS 11 and the Company's share of the assets, liabilities, revenues and expenses will be recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, the Company considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.

- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.

- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.

- Cenovus and Phillips 66, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.

- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.



Table of Contents



### Employee Benefits

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendments require the recognition of changes in defined benefit obligations and fair value of plan assets when they occur, eliminating the "corridor approach", and accelerates the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are to be recognized immediately through OCI. In addition, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendments also enhance financial statement disclosures.

The amendments to IAS 19 require retrospective application. Based on Cenovus's preliminary assessment, when the amendments are applied for the first time for the year ending December 31, 2013, net earnings for the year ended December 31, 2012 would increase by $1 million and other comprehensive income after tax would decrease by $3 million (2011 – $nil and decrease $12 million, respectively). Shareholders' equity as at December 31, 2012 would decrease by $24 million (January 1, 2012 – decrease $22 million) with corresponding adjustments, being recognized in other liabilities and deferred income taxes.

### Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "*Fair Value Measurement*" ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. IFRS 13 will not have a significant impact on the Consolidated Financial Statements.

### Financial Instruments

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses accounting for financial assets and financial liabilities. The second phase will address impairment of financial instruments and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. Although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. The Company is currently evaluating the impact of adopting IFRS 9 on its Consolidated Financial Statements.

### Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1") requiring companies to group items presented within OCI based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. The adoption of this amendment will not have a significant impact on the Consolidated Financial Statements.

### Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued the following amended standards:

- IFRS 7, "*Financial Instruments: Disclosures"* ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the Consolidated Balance Sheets or that are subject to enforceable master netting or similar arrangements.
- IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.



Table of Contents



The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. It is anticipated that IFRS 7 and IAS 32 will not have significant impacts on the Consolidated Financial Statements.

## 4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

### A) Critical Judgments in Applying Accounting Policies

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

#### *Exploration and Evaluation Assets*

The application of the Company's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is no longer technically feasible or commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

#### *Identification of CGUs*

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

### B) Key Sources of Estimation Uncertainty

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

#### *Reserves*

There are a number of inherent uncertainties associated with estimating reserves. Reserve estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would have a significant impact on the impairment test and depreciation, depletion and amortization expense of the Company's crude oil and natural gas assets. The Company's crude oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserves evaluators.

***Impairment of Assets***

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

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

At December 31, 2012, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs to sell. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

**Oil and Natural Gas Prices**

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

| | 2013 | 2014 | 2015 | 2016 | 2017 | Average Annual % Change to 2024 |
|---|---|---|---|---|---|---|
| WTI (US$/barrel) | 92.50 | 92.50 | 93.60 | 95.50 | 97.40 | 2% |
| AECO ($/Mcf) | 3.35 | 3.85 | 4.35 | 4.70 | 5.10 | 3% |

**Discount Rate**

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent which is an industry standard rate used by independent qualified reserve evaluators in preparing their reserve reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

***Decommissioning Costs***

Provisions are recognized for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

***Income Tax Provisions***

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

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



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

## 5. FINANCE COSTS

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Interest Expense – Short-Term Borrowings and Long-Term Debt | 230 | 213 | 227 |
| Interest Expense – Partnership Contribution Payable (Note 12) | 118 | 138 | 165 |
| Unwinding of Discount on Decommissioning Liabilities | 86 | 75 | 75 |
| Other | 21 | 21 | 31 |
| | 455 | 447 | 498 |

## 6. INTEREST INCOME

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Interest Income – Partnership Contribution Receivable (Note 12) | (102) | (120) | (144) |
| Other | (7) | (4) | - |
| | (109) | (124) | (144) |

## 7. FOREIGN EXCHANGE (GAIN) LOSS, NET

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Unrealized Foreign Exchange (Gain) Loss on translation of: | | | |
| U.S. Dollar Debt Issued from Canada | (69) | 78 | (182) |
| U.S. Dollar Partnership Contribution Receivable Issued from Canada | (15) | (107) | 91 |
| Other | 14 | (13) | 22 |
| Unrealized Foreign Exchange (Gain) Loss | (70) | (42) | (69) |
| Realized Foreign Exchange (Gain) Loss | 50 | 68 | 18 |
| | (20) | 26 | (51) |

## 8. INCOME TAXES

The provision for income taxes is as follows:

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Current Tax | | | |
| Canada | 188 | 150 | 82 |
| United States [1] | 121 | 4 | - |
| Total Current Tax | 309 | 154 | 82 |
| Deferred Tax | 474 | 575 | 141 |
| | 783 | 729 | 223 |

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



Table of Contents



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

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Earnings Before Income Tax** | 1,776 | 2,207 | 1,304 |
| Canadian Statutory Rate | 25.2% | 26.7% | 28.2% |
| **Expected Income Tax** | 448 | 589 | 368 |
| Effect of Taxes Resulting from: | | | |
| Foreign Tax Rate Differential | 146 | 82 | (22) |
| Non-Deductible Stock-Based Compensation | 10 | 18 | 34 |
| Multi-Jurisdictional Financing | (27) | (50) | (93) |
| Foreign Exchange Gains (Losses) Not Included in Net Earnings | 14 | (9) | 28 |
| Non-Taxable Capital (Gains) Losses | (7) | (8) | (13) |
| Recognition of Capital Losses | (22) | 26 | (107) |
| Adjustments Arising from Prior Year Tax Filings | 33 | 31 | 26 |
| Withholding Tax on Foreign Dividend | 68 | - | - |
| Goodwill Impairment | 99 | - | - |
| Other | 21 | 50 | 2 |
| **Total Tax** | 783 | 729 | 223 |
| **Effective Tax Rate** | 44.1% | 33.0% | 17.1% |

The Canadian statutory tax rate decreased to 25.2 percent in 2012 from 26.7 percent in 2011 and 28.2 percent in 2010 as a result of tax legislation enacted in 2007. The U.S. statutory tax rate has increased to 38.5 percent in 2012 from 37.5 percent in 2011 and 2010 as a result of the allocation of taxable income to U.S. states.

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

| As at December 31, | 2012 | 2011 |
|---|---|---|
| **Deferred Income Tax Liabilities** | | |
| Deferred Tax Liabilities to be Settled Within 12 Months | 140 | 117 |
| Deferred Tax Liabilities to be Settled After More Than 12 Months | 2,428 | 1,984 |
| **Net Deferred Income Tax Liability** | 2,568 | 2,101 |

For the purposes of the above table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these occur in the same entity and jurisdiction. The deferred income tax liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

| Deferred Income Tax Liabilities | Property, Plant and Equipment | Timing of Partnership Items | Net Foreign Exchange Gains | Risk Management | Other | Total |
|---|---|---|---|---|---|---|
| As at January 1, 2010 | 1,678 | 9 | 61 | 17 | - | 1,765 |
| Charged/(Credited) to Earnings | 83 | 116 | 66 | 38 | 54 | 357 |
| Charged/(Credited) to Held for Sale | 2 | - | - | - | - | 2 |
| Charged/(Credited) to OCI | (112) | - | - | - | 1 | (111) |
| As at December 31, 2010 | 1,651 | 125 | 127 | 55 | 55 | 2,013 |
| Charged/(Credited) to Earnings | 725 | 38 | (15) | 16 | 75 | 839 |
| Charged/(Credited) to OCI | 18 | - | - | - | 2 | 20 |
| As at December 31, 2011 | 2,394 | 163 | 112 | 71 | 132 | 2,872 |
| Charged/(Credited) to Earnings | 418 | (104) | (85) | 2 | (32) | 199 |
| Charged/(Credited) to OCI | (17) | - | - | - | (1) | (18) |
| **As at December 31, 2012** | **2,795** | **59** | **27** | **73** | **99** | **3,053** |

| Deferred Income Tax Assets | Unused Tax Losses | Risk Management | Other | Total |
|---|---|---|---|---|
| As at January 1, 2010 | (242) | (33) | (9) | (284) |
| Charged/(Credited) to Earnings | (47) | (12) | (161) | (220) |
| Charged/(Credited) to OCI | 8 | - | - | 8 |
| As at December 31, 2010 | (281) | (45) | (170) | (496) |
| Charged/(Credited) to Earnings | (270) | 29 | (21) | (262) |
| Charged/(Credited) to OCI | (13) | - | - | (13) |
| As at December 31, 2011 | (564) | (16) | (191) | (771) |
| Charged/(Credited) to Earnings | 244 | 11 | 20 | 275 |
| Charged/(Credited) to OCI | 11 | - | - | 11 |
| **As at December 31, 2012** | **(309)** | **(5)** | **(171)** | **(485)** |

| Net Deferred Income Tax Liabilities | Total |
|---|---|
| Net Deferred Income Tax Liabilities as at January 1, 2010 | 1,481 |
| Charged/(Credited) to Earnings | 137 |
| Charged/(Credited) to Held for Sale | 2 |
| Charged/(Credited) to OCI | (103) |
| Net Deferred Income Tax Liabilities as at December 31, 2010 | 1,517 |
| Charged/(Credited) to Earnings | 577 |
| Charged/(Credited) to OCI | 7 |
| Net Deferred Income Tax Liabilities as at December 31, 2011 | 2,101 |
| Charged/(Credited) to Earnings | 474 |
| Charged/(Credited) to OCI | (7) |
| **Net Deferred Income Tax Liabilities as at December 31, 2012** | **2,568** |

The allocation of deferred income tax expense is comprised of:

| As at December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Credited/(Charged) to Net Deferred Income Tax Liabilities | **474** | 577 | 137 |
| Credited/(Charged) to Liabilities Related to Assets Held for Sale | **-** | (2) | 4 |
| **Deferred Income Tax Expense** | **474** | 575 | 141 |

No tax liability has been recognized in respect of temporary differences associated with investments in subsidiaries. As no taxes are expected to be paid in respect of these differences related to Canadian subsidiaries, the amounts have not been determined. There are no taxable temporary differences associated with investments in non-Canadian subsidiaries.





The approximate amounts of tax pools available are as follows:

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Canada | **4,895** | 4,471 |
| United States | **1,607** | 2,740 |
| | **6,502** | 7,211 |

At December 31, 2012, the above tax pools included $13 million (2011 – $78 million; 2010 – $236 million) of Canadian non-capital losses and $791 million (2011 – $1,479 million; 2010 – $607 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2012 tax pools are Canadian net capital losses totaling $512 million (2011 – $759 million; 2010 – $983 million) which are available for carry forward to reduce future capital gains. Of these losses, $406 million are unrecognized as a deferred income tax asset at December 31, 2012 (2011 – $286 million; 2010 – $415 million). Recognition is dependent on the level of future capital gains.

## 9. PER SHARE AMOUNTS

### A) Net Earnings per Share

| For the years ended December 31, ($ millions, except earnings per share) | 2012 | 2011 | 2010 |
|---|---|---|---|
| Net Earnings – Basic and Diluted | 993 | 1,478 | 1,081 |
| Weighted Average Number of Shares – Basic | 755.6 | 754.0 | 751.9 |
| Dilutive Effect of Cenovus TSARs | 2.9 | 3.7 | 2.1 |
| Dilutive Effect of NSRs | - | - | - |
| Weighted Average Number of Shares – Diluted | 758.5 | 757.7 | 754.0 |
| Basic Earnings per share | $1.31 | $1.96 | $1.44 |
| Diluted Earnings per share | $1.31 | $1.95 | $1.43 |

### B) Dividends per Share

The dividends paid in 2012 were $665 million or $0.88 per share, (2011 – $603 million, $0.80 per share; 2010 – $601 million, $0.80 per share). The Cenovus Board of Directors declared a first quarter 2013 dividend of $0.242 per share, payable on March 28, 2013, to common shareholders of record as of March 15, 2013.

## 10. CASH AND CASH EQUIVALENTS

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Cash | 339 | 232 |
| Short-Term Investments | 821 | 263 |
| | 1,160 | 495 |



Table of Contents



## 11. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Accruals | 965 | 801 |
| Trade | 232 | 251 |
| Joint Operations with Partners | 30 | 30 |
| Prepaids and Deposits | 45 | 34 |
| Interest | 23 | 28 |
| Other | 169 | 261 |
| | 1,464 | 1,405 |

## 12. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

Cenovus has two significant joint operations, FCCL and WRB (Note 29). Through its interests in these joint operations, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Receivable and Payable which arose when Cenovus became a 50 percent partner of an integrated North American oil business. The integrated business consists of an upstream entity, FCCL, and a refining entity, WRB. On formation of the upstream entity Cenovus contributed assets, primarily Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable of an equal amount was contributed by the partner ("Partnership Contribution Receivable"). For the refining entity, the partner contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Cenovus contributed a note payable of an equal amount ("Partnership Contribution Payable").

### Partnership Contribution Receivable

This note receivable is denominated in US$ and bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Receivable shown in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of receipts to date.

#### *Mandatory Receipts – Partnership Contribution Receivable*

| | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| US$ | 386 | 407 | 429 | 452 | 117 | - | 1,791 |
| C$ equivalent | 384 | 405 | 427 | 450 | 116 | - | 1,782 |

### Partnership Contribution Payable

This note payable is denominated in US$ and bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Payable amounts shown in the Consolidated Balance Sheets represent Cenovus's

50 percent share of this promissory note, net of payments to date.

***Mandatory Payments – Partnership Contribution Payable***

| | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter | **Total** |
|---|---|---|---|---|---|---|---|
| US$ | 388 | 412 | 437 | 464 | 121 | - | **1,822** |
| C$ equivalent | 386 | 410 | 435 | 462 | 119 | - | **1,812** |



Table of Contents



## 13. INVENTORIES

| As at December 31, | **2012** | 2011 |
|---|---|---|
| **Product** | | |
| Refining and Marketing | **1,056** | 1,079 |
| Oil Sands | **202** | 186 |
| Conventional | **1** | 1 |
| **Parts and Supplies** | **29** | 25 |
| | **1,288** | 1,291 |

During the year ended December 31, 2012, approximately $12,378 million of produced and purchased inventory was recognized as an expense (2011 – $11,576 million; 2010 – $9,692 million). Inventory costs include purchased product, the cost of condensate blended with heavy oil and related operating costs.

## 14. ASSETS AND LIABILITIES HELD FOR SALE

| As at December 31, | **2012** | 2011 |
|---|---|---|
| **Assets Held for Sale** | | |
| Property, Plant and Equipment | **-** | 116 |
| **Liabilities Related to Assets Held for Sale** | | |
| Decommissioning Liabilities | **-** | 54 |
| Deferred Income Taxes | **-** | - |
| | **-** | 54 |

***Non-Core Natural Gas Assets***

At December 31, 2011, the Company classified certain non-core natural gas assets located in Northern Alberta as assets held for sale. The assets were recorded at the lesser of fair value less costs to sell and their carrying amount. This resulted in an impairment loss of approximately $2 million which has been recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income. These assets and the related liabilities were reported in the Conventional segment.

In January 2012, the Company completed the sale of these natural gas assets to an unrelated third party for net proceeds of $64 million.

## 15. EXPLORATION AND EVALUATION ASSETS

| | **E&E** |
|---|---|
| **COST** | |
| As at December 31, 2010 | 713 |
| Additions | 527 |
| Transfers to Property, Plant and Equipment (Note 16) | (356) |
| Divestitures | (3) |
| Change in Decommissioning Liabilities | (1) |
| As at December 31, 2011 | 880 |
| Additions [(1)] | 687 |
| Transfers to Property, Plant and Equipment (Note 16) | (218) |
| Exploration Expense | (68) |
| Divestitures | (11) |
| Change in Decommissioning Liabilities | 15 |
| **As at December 31, 2012** | **1,285** |

*(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.*

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

Additions to E&E assets for the year ended December 31, 2012 include $37 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – $15 million).

For the year ended December 31, 2012, $218 million of E&E assetswere transferred to property, plant and equipment – development and production assets, following the determination of technical feasibility and commercial viability of the projects (year ended December 31, 2011 – $356 million).

### Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2012, $68 million of previously capitalized E&E costs related primarily to the Roncott assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense. There were no impairment losses for the years ended December 31, 2011 and 2010.

## 16. PROPERTY, PLANT AND EQUIPMENT, NET

| | Upstream Assets | | | | |
|---|---|---|---|---|---|
| | Development & Production | Other Upstream | Refining Equipment | Other [1] | Total |
| **COST** | | | | | |
| As at December 31, 2010 | 21,720 | 153 | 2,950 | 450 | 25,273 |
| Additions | 1,704 | 41 | 391 | 131 | 2,267 |
| Transfers from E&E Assets (Note 15) | 356 | - | - | - | 356 |
| Transfers and Reclassifications | (326) | - | (5) | (2) | (333) |
| Change in Decommissioning Liabilities | 403 | - | 10 | 1 | 414 |
| Exchange Rate Movements | 1 | - | 79 | - | 80 |
| Divestitures | - | - | - | (4) | (4) |
| As at December 31, 2011 | 23,858 | 194 | 3,425 | 576 | 28,053 |
| Additions | 2,442 | 44 | 118 | 191 | 2,795 |
| Transfers from E&E Assets (Note 15) | 218 | - | - | - | 218 |
| Transfers and Reclassifications | - | - | (55) | - | (55) |
| Change in Decommissioning Liabilities | 484 | - | (16) | - | 468 |
| Exchange Rate Movements | 1 | - | (73) | - | (72) |
| Divestitures | - | - | - | - | - |
| **As at December 31, 2012** | **27,003** | **238** | **3,399** | **767** | **31,407** |
| **ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION** | | | | | |
| As at December 31, 2010 | 12,121 | 124 | 97 | 304 | 12,646 |
| Depreciation and Depletion Expense | 1,108 | 15 | 85 | 40 | 1,248 |
| Transfers and Reclassifications | (211) | - | (5) | - | (216) |
| Impairment Losses | 2 | - | 45 | - | 47 |
| Exchange Rate Movements | 1 | - | 3 | - | 4 |
| As at December 31, 2011 | 13,021 | 139 | 225 | 344 | 13,729 |
| Depreciation and Depletion Expense | 1,368 | 19 | 146 | 52 | 1,585 |
| Transfers and Reclassifications | - | - | (55) | - | (55) |
| Impairment Losses | - | - | - | - | - |
| Exchange Rate Movements | 1 | - | (5) | - | (4) |
| **As at December 31, 2012** | **14,390** | **158** | **311** | **396** | **15,255** |
| **CARRYING VALUE** | | | | | |
| As at December 31, 2010 | 9,599 | 29 | 2,853 | 146 | 12,627 |
| As at December 31, 2011 | 10,837 | 55 | 3,200 | 232 | 14,324 |
| **As at December 31, 2012** | **12,613** | **80** | **3,088** | **371** | **16,152** |

*(1) Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.*





Additions to development and production assets include internal costs directly related to the development, construction and production of crude oil and natural gas properties of $161 million (2011 – $125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized in 2012 (2011 – $nil).

Property, plant and equipment include the following amounts in respect of assets not available for use which are not subject to depreciation until put into use:

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Development and Production | 38 | 52 |
| Refining Equipment | 13 | 125 |
| Other | 11 | 112 |
| | 62 | 289 |

### Impairment

The impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income.

Depreciation, depletion and amortization expense includes impairment losses as follows:

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Development and Production | - | 2 | - |
| Refining Equipment | - | 45 | 14 |
| | - | 47 | 14 |

There were no impairments or impairment reversals of property, plant and equipment in 2012. The impairment losses for the year ended December 31, 2011 were related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations, and an impairment on non-core natural gas assets that were reclassified as held for sale (Note 14). The natural gas assets reside in the Conventional segment. The 2010 impairment loss related to a processing unit at the Borger Refinery which was determined to be a redundant asset.

## 17. DIVESTITURES

In January 2012, the Company completed the sale of non-core natural gas assets located in Northern Alberta. A loss of $2 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

In 2011, the Company disposed of non-core crude oil and natural gas properties and marine terminal facilities recognizing an after-tax gain of $91 million in the Statement of Earnings and Comprehensive Income. In 2010, an after-tax gain of $116 million was recognized on the disposition of non-core crude oil and natural gas properties and corporate assets.

## 18. OTHER ASSETS

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Long-Term Receivables | 22 | 18 |
| Prepaids | 8 | 8 |
| Other | 28 | 18 |
| | 58 | 44 |



Table of Contents



## 19. GOODWILL

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Carrying Value, Beginning of Year | 1,132 | 1,132 |
| Impairment | (393) | - |
| Carrying Value, End of Year | 739 | 1,132 |

There were no additions to goodwill during 2012 or 2011.

### Impairment Test for Cash-Generating Units Containing Goodwill

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose on the acquisition of exploration and production assets. The carrying amount of goodwill allocated to the Company's exploration and production CGUs was as follows:

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Suffield | - | 393 |
| Foster Creek | 242 | 242 |
| Northern Alberta | 497 | 497 |
| | 739 | 1,132 |

At December 31, 2012, the Company determined that the carrying amount of the Suffield CGU exceeded its fair value less costs to sell and the full amount of the impairment was attributed to goodwill. This goodwill arose in 2002 upon the formation of the predecessor corporation. An impairment loss of $393 million was recorded as goodwill impairment on the Consolidated Statement of Earnings and Comprehensive Income. The Suffield property resides on the Canadian Forces Base in southeast Alberta and the operating results are included in the Conventional segment. Future cash flows for the area have declined due to lower natural gas and crude oil prices and increased operating costs. In addition, minimal levels of capital spending for natural gas resulted in production exceeding reserve replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the goodwill exceeded its fair value.

The recoverable amount was determined using fair value less costs to sell. A calculation based on discounted after-tax cash flows of proved and probable reserves using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators was completed (Note 4). To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed.

There was no impairment of goodwill in 2011 or 2010.

### Sensitivities

Changes to the assumed discount rate or forward price estimates independently would have the following impact on the impairment of the Suffield CGU:

| | One Percent Increase in the Discount Rate | Five Percent Decrease in the Forward Price Estimates |
|---|---|---|
| Impairment of Goodwill | - | - |
| Impairment of PP&E | 50 | 100 |



Table of Contents



## 20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Accruals | 1,510 | 1,193 |
| Trade | 676 | 789 |
| Employee Long-Term Incentives | 196 | 209 |
| Interest | 82 | 72 |
| Other | 186 | 316 |
| | 2,650 | 2,579 |

## 21. LONG-TERM DEBT

| As at December 31, | | 2012 | 2011 |
|---|---|---|---|
| Revolving Term Debt [1] | A | - | - |
| U.S. Dollar Denominated Unsecured Notes | B | 4,726 | 3,559 |
| Total Debt Principal | C | 4,726 | 3,559 |
| Debt Discounts and Transaction Costs | D | (47) | (32) |
| | | 4,679 | 3,527 |

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

The weighted average interest rate on outstanding debt for the year ended December 31, 2012 was 5.3 percent (2011 – 5.5 percent, 2010 – 5.8 percent).

### A) Revolving Term Debt

At December 31, 2012, Cenovus had in place a committed credit facility in the amount of $3.0 billion or the equivalent amount in U.S. dollars. The committed credit facility was renegotiated in September 2012 to slightly reduce both the standby fees required to maintain the facility as well as the cost of future borrowings. The maturity date was extended to November 30, 2016 and is extendable from time to time, for a period of up to four years at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. At December 31, 2012, there were no amounts drawn on Cenovus's committed bank credit facility (2011 – $nil).

### B) Unsecured Notes

Unsecured notes are comprised of the following:

| As at December 31, | US$ Principal Amount | 2012 | 2011 |
|---|---|---|---|
| 4.50% due September 15, 2014 | 800 | 796 | 814 |
| 5.70% due October 15, 2019 | 1,300 | 1,293 | 1,322 |
| 3.00% due August 15, 2022 | 500 | 498 | - |
| 6.75% due November 15, 2039 | 1,400 | 1,393 | 1,423 |
| 4.45% due September 15, 2042 | 750 | 746 | - |
| | 4,750 | 4,726 | 3,559 |

Cenovus has in place a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.



Table of Contents



Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2012, US$750 million remains under this U.S. base shelf

prospectus. The U.S. shelf prospectus expires in July 2014.

On August 17, 2012, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$500 million, with a coupon rate of 3.00 percent, due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042, for an aggregate principal amount of US$1.25 billion. The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

As at December 31, 2012, the Company is in compliance with all of the terms of its debt agreements.

### C) Mandatory Debt Payments

| | US$ Principal Amount | C$ Principal Amount | Total C$ Equivalent |
|---|---|---|---|
| 2013 | - | - | - |
| 2014 | 800 | - | 796 |
| 2015 | - | - | - |
| 2016 | - | - | - |
| 2017 | - | - | - |
| Thereafter | 3,950 | - | 3,930 |
| | 4,750 | - | 4,726 |

### D) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are being amortized over the remaining term of the committed credit facility. During 2012, additional transaction costs of $19 million were recorded (2011 – $3 million).

## 22. DECOMMISSIONING LIABILITIES

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

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Decommissioning Liabilities, Beginning of Year | 1,777 | 1,399 |
| Liabilities Incurred | 99 | 49 |
| Liabilities Settled | (66) | (56) |
| Transfers and Reclassifications | 3 | (55) |
| Change in Estimated Future Cash Flows | 144 | 146 |
| Change in Discount Rate | 273 | 218 |
| Unwinding of Discount on Decommissioning Liabilities | 86 | 75 |
| Foreign Currency Translation | (1) | 1 |
| Decommissioning Liabilities, End of Year | 2,315 | 1,777 |

The undiscounted amount of estimated cash flows required to settle the obligation is $6,865 million (2011 – $6,541 million), which has been discounted using a credit-adjusted risk-free rate of 4.2 percent (2011 – 4.8 percent). Most of these obligations are not expected to be paid for several years, or decades, and will be funded from general resources at that time. Revisions in estimated cash flows resulted from accelerated timing of forecast abandonment and reclamation spending and higher cost estimates.



Table of Contents



### Sensitivities

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

| | 2012 | | 2011 | |
|---|---|---|---|---|
| As at December 31, | Credit-Adjusted Risk-Free Rate | Inflation Rate | Credit-Adjusted Risk-Free Rate | Inflation Rate |
| One Percent Increase | (408) | 572 | (367) | 504 |
| One Percent Decrease | 565 | (418) | 494 | (379) |

## 23. OTHER LIABILITIES

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Deferred Revenue | 31 | 35 |
| Employee Long-Term Incentives | 64 | 55 |
| Pension and Other Post-Employment Benefits (Note 24) | 28 | 16 |
| Other | 28 | 22 |
| | 151 | 128 |

## 24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and other post-employment benefit plans ("OPEB"). Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria are eligible to elect to convert from

the current defined contribution pension to a defined benefit pension.

The Company is required to file an actuarial valuation of its registered defined benefit pension plan with the provincial regulator at least every three years. The most recently filed valuation was dated June 30, 2012 and the next required actuarial valuation will be as at December 31, 2014.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The defined benefit pension is funded according to the federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plans are based on the results of the actuarial valuation and direction by the Human Resources and Compensation Committee of the Board.

The Company's OPEB provides retired employees with life insurance benefits, health care and dental benefits until age 65. These benefits are funded on an as required basis.



Table of Contents



### A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is as follows:

| | Pension Benefits | | OPEB | |
|---|---|---|---|---|
| As at December 31, | 2012 | 2011 | 2012 | 2011 |
| **Defined Benefit Obligation** | | | | |
| Defined Benefit Obligation, Beginning of Year | 84 | 68 | 19 | 14 |
| Current Service Costs | 10 | 3 | 2 | 2 |
| Interest Costs | 4 | 3 | 1 | 1 |
| Benefits Paid | (2) | (1) | - | - |
| Plan Participant Contributions | 1 | - | - | - |
| Actuarial (Gains) Losses | 7 | 11 | (2) | 2 |
| Plan Conversion | 30 | - | - | - |
| Defined Benefit Obligation, End of Year | 134 | 84 | 20 | 19 |
| **Plan Assets** | | | | |
| Fair Value of Plan Assets, Beginning of Year | 61 | 59 | - | - |
| Expected Return on Plan Assets | 4 | 3 | - | - |
| Employer Contributions | 22 | 4 | - | - |
| Plan Participant Contributions | 1 | - | - | - |
| Actuarial Gains (Losses) | - | (4) | - | - |
| Benefits Paid | (2) | (1) | - | - |
| Asset Transfer from Plan Conversion | 12 | - | - | - |
| Fair Value of Plan Assets, End of Year | 98 | 61 | - | - |
| Funded Status – Plan Assets (Less) than Benefit Obligation | (36) | (23) | (20) | (19) |
| Unamortized Net Actuarial (Gain) Loss not Recognized | 26 | 22 | 2 | 4 |
| **Pension and Other Post-Employment Benefit (Liability)** | (10) | (1) | (18) | (15) |

The pension and other post-employment benefit liability is included in other liabilities on the Consolidated Balance Sheets.

### B) Pension and Other Post-Employment Benefit Costs

Pension and other post-employment benefit costs are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| Current Service Cost | 10 | 3 | 3 | 3 | 2 | 1 |
| Interest Cost | 4 | 4 | 3 | 1 | 1 | 1 |
| Expected Return on Plan Assets | (4) | (4) | (3) | - | - | - |
| Actuarial Gains (Losses) | 3 | 1 | - | - | - | - |
| Past Service Cost [1] | 18 | - | - | - | - | - |
| Defined Benefit Plan Cost | 31 | 4 | 3 | 4 | 3 | 2 |
| Defined Contribution Plan Cost | 25 | 22 | 18 | - | - | - |
| Total Plan Cost | 56 | 26 | 21 | 4 | 3 | 2 |

*(1) Past service costs for eligible employees who were given a one-time option to convert from the defined contribution pension to defined benefit pension retrospectively to the later of the date they would have been eligible to enroll in the defined benefit pension or November 30, 2009. Past service costs were fully vested and recorded immediately.*

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



Table of Contents

### C) Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Benefit Obligation at December 31** | | | | | | |
| Discount Rate | 4.00% | 4.25% | 5.25% | 4.00% | 4.25% | 5.25% |
| Rate of Compensation Increase | 4.39% | 3.99% | 4.05% | 5.77% | 5.77% | 5.65% |
| **Benefit Expense for the Year** | | | | | | |
| Discount Rate | 4.25% | 5.25% | 6.00% | 4.25% | 5.25% | 6.00% |
| Expected Return on Plan Assets | 5.54% | 5.59% | 5.59% | N/A | N/A | N/A |
| Rate of Compensation Increase | 3.99% | 4.05% | 4.05% | 5.77% | 5.65% | 5.77% |

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio.

The expected average remaining service period of the active employees covered by the defined benefit pension and OPEB plans are seven and 11 years, respectively.

Assumed health care cost trend rates are as follows:

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Health Care Cost Trend for Next Year | 8% | 10% | 10% |
| Rate that the Trend Rate Gradually Trends to | 5% | 5% | 5% |
| Year that the Trend Rate Reaches the Rate Which it is Expected to Remain At | 2021 | 2022 | 2021 |

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

| | One Percentage Point Increase | One Percentage Point Decrease |
|---|---|---|
| Effect on Service and Interest Cost | - | - |
| Effect on Pension and Other Post-Employment Benefit Liability | 1 | (1) |

### D) Plan Assets and Investment Objectives

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The actual return on the plan assets for the year ended December 31, 2012 was $3 million (2011 – $nil).

The Company's weighted average pension plan asset allocation, based on market values as at December 31, 2011 and 2010, are as follows:

| | Target Allocation | Percentage of Plan Assets | |
|---|---|---|---|
| | | 2012 | 2011 |
| Equity Securities | 65-70% | 63% | 60% |
| Debt Securities | 30% | 30% | 33% |
| Real Estate and Other | 0-5% | 7% | 7% |
| Total | 100% | 100% | 100% |

Equity securities do not include any direct investments in Cenovus shares.



Table of Contents



The expected contributions for the year ended December 31, 2013 is $15 million for the defined benefit pension plan and $nil for the OPEB.

### E) Defined Benefit Plan and OPEB Experience Adjustments

Experience adjustments as a percentage of total plan assets and liabilities are as follows:

| As at December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Defined Benefit** | | | |
| Experience Adjustments Arising on Plan Liabilities | 2% | (1)% | 3% |
| Experience Adjustments Arising on Plan Assets | 0% | 7% | (2)% |
| **OPEB** | | | |
| Experience Adjustments Arising on Plan Liabilities | 3% | 2% | 2% |

## 25. SHARE CAPITAL

### A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

### B) Issued and Outstanding

| | 2012 | | 2011 | |
|---|---|---|---|---|
| As at December 31, | Number of Common Shares (thousands) | Amount | Number of Common Shares (thousands) | Amount |
| Outstanding, Beginning of Year | 754,499 | 3,780 | 752,675 | 3,716 |
| Common Shares Issued under Stock Option Plans | 1,344 | 49 | 1,824 | 64 |
| Outstanding, End of Year | 755,843 | 3,829 | 754,499 | 3,780 |

There were no preferred shares outstanding as at December 31, 2012 (2011 – nil).

At December 31, 2012, there were 28 million (2011 – 30 million) common shares available for future issuance under stock option plans.

The Company has a dividend reinvestment plan ("DRIP"). Under the DRIP, holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury or purchased on the market.



Table of Contents



### C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana under the Arrangement into two independent energy companies, Encana and Cenovus. In addition, paid in surplus includes compensation expense related to the Company's NSRs discussed in Note 26 A.

| | Pre-Arrangement Earnings | Stock-Based Compensation | Total |
|---|---|---|---|
| As at December 31, 2010 | 4,083 | - | 4,083 |
| Stock-Based Compensation Expense | - | 24 | 24 |
| As at December 31, 2011 | 4,083 | 24 | 4,107 |
| Stock-Based Compensation Expense | - | 47 | 47 |
| As at December 31, 2012 | 4,083 | 71 | 4,154 |

## 26. STOCK-BASED COMPENSATION PLANS

### A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

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

In addition, certain of the TSARs are performance based ("Performance TSARs"). The Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and have an additional vesting requirement whereby vesting is subject to achievement of prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited.

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus Replacement TSARs are measured against the Cenovus common share price while Encana Replacement TSARs are measured against the Encana common share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

| As at December 31, 2012 | Issued | Term (Years) | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price ($) | Closing Share Price ($) | Units Outstanding |
|---|---|---|---|---|---|---|
| Encana Replacement TSARs held by Cenovus Employees | Prior to Arrangement | 5 | 0.66 | 32.66 | 19.66 | 7,722 |
| Cenovus Replacement TSARs held by Encana Employees | Prior to Arrangement | 5 | 0.70 | 29.29 | 33.29 | 5,229 |
| TSARs | Prior to February 17, 2010 | 5 | 0.72 | 29.28 | 33.29 | 6,225 |
| TSARs | On or After February 17, 2010 | 7 | 4.20 | 26.71 | 33.29 | 5,026 |
| NSRs | On or After February 24, 2011 | 7 | 5.85 | 37.52 | 33.29 | 15,074 |

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

***NSRs***

The weighted average unit fair value of NSRs granted during the year ended December 31, 2012 was $7.62 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

| | |
|---|---|
| Risk-Free Interest Rate | 1.37% |
| Expected Dividend Yield | 2.31% |
| Expected Volatility [(1)] | 28.62% |
| Expected Life (Years) | 4.55 |

*(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The following tables summarize information related to the NSRs as at December 31, 2012:

| As at December 31, 2012 (thousands of units) | NSRs | Weighted Average Exercise Price ($) |
|---|---|---|
| Outstanding, Beginning of Year | 5,809 | 36.95 |
| Granted | 9,665 | 37.87 |
| Exercised for Common Shares | (5) | 33.99 |
| Forfeited | (395) | 37.56 |
| Outstanding, End of Year | 15,074 | 37.52 |
| Exercisable, End of Year | 1,700 | 36.98 |

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $35.28.

| | Outstanding NSRs (thousands of units) | | |
|---|---|---|---|
| As at December 31, 2012 Range of Exercise Price ($) | NSRs | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price ($) |
| 30.00 to 39.99 | 15,074 | 5.85 | 37.52 |

| | Exercisable NSRs (thousands of units) | |
|---|---|---|
| As at December 31, 2012 Range of Exercise Price ($) | NSRs | Weighted Average Exercise Price ($) |
| 30.00 to 39.99 | 1,700 | 36.98 |



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

***TSARs Held by Cenovus Employees***

The Company has recorded a liability of $64 million at December 31, 2012 (December 31, 2011 – $90 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

| | |
|---|---|
| Risk-Free Interest Rate | 1.28% |
| Expected Dividend Yield | 2.58% |
| Expected Volatility [1] | 27.80% |
| Cenovus's Common Share Price | $33.29 |

*(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2012 was $45 million (2011 – $43 million).

The following tables summarize information related to the TSARs held by Cenovus employees as at December 31, 2012:

| As at December 31, 2012 (thousands of units) | TSARs | Performance TSARs | Total | Weighted Average Exercise Price ($) |
|---|---|---|---|---|
| Outstanding, Beginning of Year | 9,391 | 5,530 | 14,921 | 28.12 |
| Granted | - | - | - | - |
| Exercised for Cash Payment | (937) | (1,057) | (1,994) | 28.52 |
| Exercised as Options for Common Shares | (683) | (641) | (1,324) | 27.77 |
| Forfeited | (134) | (207) | (341) | 26.77 |
| Expired | (11) | - | (11) | 30.85 |
| Outstanding, End of Year | 7,626 | 3,625 | 11,251 | 28.13 |
| Exercisable, End of Year | 5,369 | 3,625 | 8,994 | 28.46 |

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.73.

| | Outstanding TSARs (thousands of units) | | | | |
|---|---|---|---|---|---|
| As at December 31, 2012 Range of Exercise Price ($) | TSARs | Performance TSARs | Total | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price ($) |
| 20.00 to 29.99 | 6,269 | 2,143 | 8,412 | 2.88 | 26.38 |
| 30.00 to 39.99 | 1,294 | 1,482 | 2,776 | 0.48 | 33.10 |
| 40.00 to 49.99 | 63 | - | 63 | 0.45 | 43.29 |
| | 7,626 | 3,625 | 11,251 | 2.27 | 28.13 |

| | Exercisable TSARs (thousands of units) | | | |
|---|---|---|---|---|
| As at December 31, 2012 Range of Exercise Price ($) | TSARs | Performance TSARs | Total | Weighted Average Exercise Price ($) |
| 20.00 to 29.99 | 4,132 | 2,143 | 6,275 | 26.35 |
| 30.00 to 39.99 | 1,174 | 1,482 | 2,656 | 33.11 |
| 40.00 to 49.99 | 63 | - | 63 | 43.29 |
| | 5,369 | 3,625 | 8,994 | 28.46 |

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

### *Encana Replacement TSARs Held by Cenovus Employees*

Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana Replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of $1 million at December 31, 2012 (2011 - $1 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

| | |
|---|---|
| Risk-Free Interest Rate | 1.21% |
| Expected Dividend Yield | 3.86% |
| Expected Volatility [1] | 30.40% |
| Encana's Common Share Price | $19.66 |

*(1) Expected volatility has been based on the historical volatility of Encana's publicly traded shares.*

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at December 31, 2012 was $nil (2011 – $nil).

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2012:

| As at December 31, 2012 (thousands of units) | TSARs | Performance TSARs | Total | Weighted Average Exercise Price ($) |
|---|---|---|---|---|
| Outstanding, Beginning of Year | 4,281 | 6,130 | 10,411 | 31.97 |
| Exercised for Cash Payment | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Exercised as Options for Encana Common Shares | - | - | - | - |
| Forfeited | (112) | (333) | (445) | 31.04 |
| Expired | (1,008) | (1,236) | (2,244) | 29.79 |
| Outstanding, End of Year | 3,161 | 4,561 | 7,722 | 32.66 |
| Exercisable, End of Year | 3,161 | 4,561 | 7,722 | 32.66 |

| | Outstanding & Exercisable TSARs (thousands of units) | | | | |
|---|---|---|---|---|---|
| As at December 31, 2012<br>Range of Exercise Price ($) | TSARs | Performance TSARs | Total | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price ($) |
| 20.00 to 29.99 | 1,564 | 2,510 | 4,074 | 1.12 | 29.02 |
| 30.00 to 39.99 | 1,465 | 2,051 | 3,516 | 0.15 | 36.41 |
| 40.00 to 49.99 | 130 | - | 130 | 0.48 | 44.85 |
| 50.00 to 59.99 | 2 | - | 2 | 0.39 | 50.39 |
| | 3,161 | 4,561 | 7,722 | 0.66 | 32.66 |

The closing price of Encana common shares on the TSX as at December 31, 2012 was $19.66.

***Cenovus Replacement TSARs Held by Encana Employees***

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana employees when these employees exercise a Cenovus Replacement TSAR for cash. No compensation expense is recognized and no further Cenovus Replacement TSARs will be granted to Encana employees.



Table of Contents



The Company has recorded a liability of $35 million at December 31, 2012 (2011 – $83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

| | |
|---|---|
| Risk-Free Interest Rate | 1.21% |
| Expected Dividend Yield | 2.58% |
| Expected Volatility (1) | 27.80% |
| Cenovus's Common Share Price | $33.29 |

*(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at December 31, 2012 was $22 million (2011 – $32 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2012:

| As at December 31, 2012<br>(thousands of units) | TSARs | Performance TSARs | Total | Weighted Average Exercise Price ($) |
|---|---|---|---|---|
| Outstanding, Beginning of Year | 3,935 | 5,751 | 9,686 | 28.96 |
| Exercised for Cash Payment | (1,788) | (2,189) | (3,977) | 28.69 |
| Exercised as Options for Common Shares | (8) | (12) | (20) | 26.64 |
| Forfeited | (84) | (314) | (398) | 27.67 |
| Expired | (30) | (32) | (62) | 27.67 |
| Outstanding, End of Year | 2,025 | 3,204 | 5,229 | 29.29 |
| Exercisable, End of Year | 2,025 | 3,204 | 5,229 | 29.29 |

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $36.72.

| | Outstanding & Exercisable TSARs (thousands of units) | | | | |
|---|---|---|---|---|---|
| As at December 31, 2012<br>Range of Exercise Price ($) | TSARs | Performance TSARs | Total | Weighted Average Remaining Contractual Life (Years) | Weighted Average Exercise Price ($) |
| 20.00 to 29.99 | 1,087 | 1,899 | 2,986 | 1.12 | 26.27 |
| 30.00 to 39.99 | 886 | 1,305 | 2,191 | 0.14 | 33.08 |
| 40.00 to 49.99 | 52 | - | 52 | 0.44 | 42.70 |
| | 2,025 | 3,204 | 5,229 | 0.70 | 29.29 |

The closing price of Cenovus common shares on the TSX as at December 31, 2012 was $33.29.

**B) Performance Share Units**

Cenovus has granted Performance Share Units ("PSUs") to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $124 million at December 31, 2012 (2011 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2012. The intrinsic value of vested PSUs was $nil at December 31, 2012 and 2011 as PSUs are paid out upon vesting.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

The following table summarizes the information related to the PSUs held by Cenovus employees as at December 31, 2012:

| (thousands of units) | PSUs |
|---|---|
| Outstanding, Beginning of Year | 2,623 |
| Granted | 2,704 |
| Cancelled | (183) |
| Units in Lieu of Dividends | 114 |
| Outstanding, End of Year | 5,258 |

### C) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive Deferred Share Units ("DSUs"), which are equivalent in value to a common share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $36 million at December 31, 2012 (2011 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2012. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2012:

| (thousands of units) | DSUs |
|---|---|
| Outstanding, Beginning of Year | 1,042 |
| Granted to Directors | 64 |
| Granted from Annual Bonus Awards | 22 |
| Units in Lieu of Dividends | 30 |
| Exercised | (74) |
| Outstanding, End of Year | 1,084 |

### D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses on the Consolidated Statements of Earnings and Comprehensive Income:

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| NSRs | 27 | 16 | - |
| TSARs Held by Cenovus Employees | (1) | 24 | 45 |
| Encana Replacement TSARs Held by Cenovus Employees | - | (8) | (20) |
| PSUs | 46 | 27 | 13 |
| DSUs | 3 | 4 | 9 |
| **Total Stock-Based Compensation Expense (Recovery)** | 75 | 63 | 47 |

## 27. EMPLOYEE SALARIES AND BENEFIT EXPENSES

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Salaries, Bonuses and Other Short-Term Employee Benefits | 441 | 399 | 348 |
| Defined Contribution Pension Plan | 14 | 13 | 11 |
| Defined Benefit Pension Plan and OPEB | 20 | 4 | (1) |
| Stock-Based Compensation (Note 26) | 75 | 63 | 47 |
| | 550 | 479 | 405 |



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

## 28. RELATED PARTY TRANSACTIONS

### Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is as follows:

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Salaries, Director Fees and Short-Term Benefits | 27 | 25 | 22 |
| Post-Employment Benefits | 7 | 3 | 2 |
| Other Long-Term Benefits | - | - | - |
| Stock-Based Compensation | 35 | 35 | 37 |
| **Total** | 69 | 63 | 61 |

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recognized during the year associated with stock options, NSRs, TSARs, PSUs and DSUs.

## 29. INTEREST IN JOINT OPERATIONS

On January 2, 2007, Cenovus became a 50 percent partner in an integrated North American heavy oil business. The integrated business is structured through two joint arrangements. The upstream entity, FCCL Partnership, is involved in the development and production of crude oil and is jointly controlled with ConocoPhillips. The refining entity, WRB Refining LP, includes two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with Phillips 66.

Cenovus recognizes its share of the assets, liabilities, revenues and expenses (proportionately consolidates) of these joint operations with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Cenovus's Consolidated Financial Statements include the following amounts related to these joint arrangements:

| | FCCL Partnership [1] | | | WRB Refining LP [1] | | |
|---|---|---|---|---|---|---|
| Statements of Earnings<br>For the years ended December 31, | 2012 | 2011 | 2010 | 2012 | 2011 | 2010 |
| **Revenues** | 3,132 | 2,364 | 1,829 | 9,160 | 8,672 | 6,624 |
| **Expenses** | | | | | | |
| Purchased Product | - | - | - | 7,339 | 7,223 | 6,095 |
| Operating, Transportation and Blending and Realized Gain/Loss on Risk Management | 1,944 | 1,397 | 1,074 | 552 | 473 | 462 |
| **Operating Cash Flow** | 1,188 | 967 | 755 | 1,269 | 976 | 67 |
| Depreciation, Depletion and Amortization | 303 | 205 | 210 | 135 | 130 | 86 |
| Other Expenses (Income) | 1 | (136) | 20 | 4 | (4) | 13 |
| **Net Earnings (Loss)** | 884 | 898 | 525 | 1,130 | 850 | (32) |

*(1) FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.*

| | FCCL Partnership | | WRB Refining LP | |
|---|---|---|---|---|
| As at December 31, | 2012 | 2011 | 2012 | 2011 |
| Cash and Cash Equivalents | 388 | 145 | 172 | 166 |
| Other Current Assets | 761 | 792 | 1,111 | 1,236 |
| Long-Term Assets | 7,599 | 6,864 | 3,087 | 3,188 |
| Current Liabilities | 350 | 317 | 566 | 759 |
| Long-Term Liabilities | 137 | 83 | 58 | 73 |



Table of Contents



Capital commitments through jointly controlled entities are as follows:

| As at December 31, 2012 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Capital Commitments [1] | 268 | 34 | 44 | 40 | 2 | 1 | 389 |

*(1) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.*

| As at December 31, 2011 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Capital Commitments [1] | 179 | 58 | 11 | 2 | 3 | - | 253 |

*(1) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.*

There are no contingent liabilities related to the Company's interest in jointly controlled entities, nor contingent liabilities of the jointly controlled entities themselves.

## 30. CAPITAL STRUCTURE

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

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

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

| As at December 31, | 2012 | 2011 |
|---|---|---|

| | | | |
|---|---|---|---|
| Long-Term Debt | **4,679** | 3,527 |
| Shareholders' Equity | **9,806** | 9,406 |
| Capitalization | **14,485** | 12,933 |
| **Debt to Capitalization** | **32%** | 27% |

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

| As at December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Debt | **4,679** | 3,527 | 3,432 |
| Net Earnings | **993** | 1,478 | 1,081 |
| Add (Deduct): | | | |
| Finance Costs | **455** | 447 | 498 |
| Interest Income | **(109)** | (124) | (144) |
| Income Tax Expense | **783** | 729 | 223 |
| Depreciation, Depletion and Amortization | **1,585** | 1,295 | 1,302 |
| Goodwill Impairment | **393** | - | - |
| Exploration Expense | **68** | - | - |
| Unrealized (Gain) Loss on Risk Management | **(57)** | (180) | (46) |
| Foreign Exchange (Gain) Loss, net | **(20)** | 26 | (51) |
| (Gain) Loss on Divestiture of Assets | **-** | (107) | (116) |
| Other (Income) Loss, net | **(5)** | 4 | (13) |
| Adjusted EBITDA | **4,086** | 3,568 | 2,734 |
| **Debt to Adjusted EBITDA** | **1.1x** | 1.0x | 1.3x |



Table of Contents



It is Cenovus's intention to maintain investment grade credit ratings to help ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

At December 31, 2012, Cenovus is in compliance with all of the terms of its debt agreements.

## 31. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

### A) Fair Value of Financial Assets and Liabilities

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

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable, partner loans and long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on prices sourced from market data. As at December 31, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $4,679 million and the fair value was $5,582 million (December 31, 2011 carrying value – $3,527 million, fair value – $4,316 million).

### B) Risk Management Assets and Liabilities

Under the terms of the Arrangement, risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

#### *Net Risk Management Position*

| As at December 31, | 2012 | 2011 |
|---|---|---|
| **Risk Management Assets** | | |
| Current Asset | **283** | 232 |
| Long-Term Asset | **5** | 52 |
| | **288** | 284 |
| **Risk Management Liabilities** | | |
| Current Liability | **17** | 54 |
| Long-Term Liability | **1** | 14 |
| | **18** | 68 |
| **Net Risk Management Asset (Liability)** | **270** | 216 |

### *Summary of Unrealized Risk Management Positions*

| | 2012 | | | 2011 | | |
|---|---|---|---|---|---|---|
| | | Risk Management | | | Risk Management | |
| As at December 31, | Asset | Liability | Net | Asset | Liability | Net |
| **Commodity Prices** | | | | | | |
| Crude Oil | 221 | 16 | 205 | 22 | 65 | (43) |
| Natural Gas | 66 | 1 | 65 | 247 | 3 | 244 |
| Power | 1 | 1 | - | 15 | - | 15 |
| **Total Fair Value** | 288 | 18 | 270 | 284 | 68 | 216 |

### *Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions*

| As at December 31, | 2012 | 2011 |
|---|---|---|
| Prices Actively Quoted (Level 1) | 120 | 226 |
| Prices Sourced from Observable Data or Market Corroboration (Level 2) | 150 | (10) |
| Total Fair Value | 270 | 216 |

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

### *Net Fair Value of Commodity Price Positions at December 31, 2012*

| As at December 31, 2012 | Notional Volumes | Term | Average Price | Fair Value |
|---|---|---|---|---|
| **Crude Oil Contracts** | | | | |
| Fixed Price Contracts | | | | |
| Brent Fixed Price [1] | 18,500 bbls/d | 2013 | US$110.36/bbl | 23 |
| Brent Fixed Price [1] | 18,500 bbls/d | 2013 | $111.72/bbl | 33 |
| WCS Differential [2] | 49,200 bbls/d | 2013 | US$(20.74)/bbl | 145 |
| WCS Differential [2] | 9,400 bbls/d | 2014 | US$(20.13)/bbl | 5 |
| Other Financial Positions [3] | | | | (1) |
| Crude Oil Fair Value Position | | | | 205 |
| **Natural Gas Contracts** | | | | |
| Fixed Price Contracts | | | | |
| NYMEX Fixed Price | 166 MMcf/d | 2013 | US$4.64/Mcf | 66 |
| Other Fixed Price Contracts [4] | | | | (1) |
| Natural Gas Fair Value Position | | | | 65 |
| **Power Purchase Contracts** | | | | |
| Power Fair Value Position | | | | - |

*(1) Brent fixed price positions consist of both Brent fixed price swaps and WTI swaps converted to Brent.*
*(2) Cenovus has entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.*
*(3) Other financial positions are part of ongoing operations to market the Company's production.*
*(4) Cenovus has entered into other fixed price contracts to protect against widening price differentials between production areas and various sales points.*



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

### *Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions*

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| **Realized Gain (Loss)** [1] | | | |
| Crude Oil | 81 | (135) | (17) |
| Natural Gas | 247 | 210 | 289 |
| Refining | 7 | (14) | 10 |
| Power | 1 | 7 | (4) |
| | 336 | 68 | 278 |
| **Unrealized Gain (Loss)** [2] | | | |
| Crude Oil | 247 | 106 | (92) |
| Natural Gas | (176) | 38 | 152 |
| Refining | 1 | 7 | (8) |
| Power | (15) | 29 | (6) |
| | 57 | 180 | 46 |
| **Gain (Loss) on Risk Management** | 393 | 248 | 324 |

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

***Reconciliation of Unrealized Risk Management Positions from January 1 to December 31, 2012***

| | 2012 | | 2011 | 2010 |
|---|---|---|---|---|
| | Fair Value | Total Unrealized Gain (Loss) | Total Unrealized Gain (Loss) | Total Unrealized Gain (Loss) |
| Fair Value of Contracts, Beginning of Year | 216 | | | |
| Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year | 393 | 393 | 248 | 324 |
| Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts | (3) | - | - | - |
| Fair Value of Contracts Realized During the Year | (336) | (336) | (68) | (278) |
| Fair Value of Contracts, End of Year | 270 | 57 | 180 | 46 |

***Commodity Price Sensitivities – Risk Management Positions***

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

**Risk Management Positions in Place as at December 31, 2012**

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10 per bbl Applied to Brent and WTI Hedges | (156) | 156 |
| Crude Oil Differential Price | ± US$5 per bbl Applied to Differential Hedges tied to Production | 111 | (111) |
| Natural Gas Commodity Price | ± $1 per mcf Applied to NYMEX Natural Gas Hedges | (55) | 55 |
| Natural Gas Basis Price | ± $0.10 per mcf Applied to Natural Gas Basis Hedges | 1 | (1) |
| Power Commodity Price | ± $25 per MWHr Applied to Power Hedge | 19 | (19) |

**Risk Management Positions in Place as at December 31, 2011**

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10 per bbl Applied to WTI Hedges | (214) | 214 |
| Crude Oil Differential Price | ± US$5 per bbl Applied to Differential Hedges tied to Production | 67 | (67) |
| Natural Gas Commodity Price | ± $1 per mcf Applied to NYMEX and AECO Hedges | (160) | 160 |
| Natural Gas Basis Price | ± $0.10 per mcf Applied to Natural Gas Basis Hedges | 2 | (2) |
| Power Commodity Price | ± $25 per MWHr Applied to Power Hedge | 19 | (19) |



Table of Contents



## C) Risks Associated with Financial Assets and Liabilities

***Commodity Price Risk***

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX price. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

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

***Credit Risk***

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with large commercial counterparties, most of which have investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. At December 31, 2012 and 2011, substantially all of the Company's accounts receivable were current. As at December 31, 2012, 87 percent (2011 – 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2012, Cenovus had two counterparties (2011 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value. The majority of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

***Liquidity Risk***

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 30, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. At December 31, 2012, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$750 million under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

Undiscounted cash outflows relating to financial liabilities are:

| 2012 | Less than 1 Year | 1-3 Years | 4-5 Years | Thereafter | Total |
|---|---|---|---|---|---|
| Accounts Payable and Accrued Liabilities | 2,650 | - | - | - | **2,650** |
| Risk Management Liabilities | 17 | 1 | - | - | **18** |
| Long-Term Debt [1] | 254 | 1,263 | 432 | 7,051 | **9,000** |
| Partnership Contribution Payable [1] | 486 | 972 | 609 | - | **2,067** |
| Other [1] | - | 9 | 4 | 4 | **17** |

*(1) Principal and interest, including current portion.*

| 2011 | Less than 1 Year | 1-3 Years | 4-5 Years | Thereafter | Total |
|---|---|---|---|---|---|
| Accounts Payable and Accrued Liabilities | 2,579 | - | - | - | 2,579 |
| Risk Management Liabilities | 54 | 14 | - | - | 68 |
| Long-Term Debt [1] | 208 | 1,230 | 343 | 5,182 | 6,963 |
| Partnership Contribution Payable [1] | 497 | 994 | 994 | 125 | 2,610 |
| Other [1] | 3 | 10 | 3 | 4 | 20 |

*(1) Principal and interest, including current portion.*

### *Foreign Exchange Risk*

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At December 31, 2012, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2011 – US$3,500 million; 2010 – US$3,500 million) and US$1,791 million related to the U.S. dollar Partnership Contribution Receivable (2011 – US$2,157 million; 2010 – US$2,505 million). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $30 million change in foreign exchange (gain) loss at December 31, 2012 (2011 – $13 million; 2010 – $10 million).

### *Interest Rate Risk*

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2011 – $nil; 2010 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

## 32. SUPPLEMENTARY CASH FLOW INFORMATION

| For the years ended December 31, | 2012 | 2011 | 2010 |
|---|---|---|---|
| Interest Paid | **342** | 357 | 423 |
| Interest Received | **113** | 128 | 148 |
| Income Taxes Paid | **304** | - | 62 |



Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
*All amounts in $ millions, unless otherwise indicated*
*For the year ended December 31, 2012*

## 33. COMMITMENTS AND CONTINGENCIES

### A) Commitments

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

| 2012 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Pipeline Transportation [1] | 145 | 209 | 378 | 403 | 675 | 8,130 | **9,940** |
| Operating Leases (Building Leases) | 109 | 106 | 112 | 110 | 104 | 1,602 | **2,143** |
| Product Purchases | 81 | 18 | 18 | 6 | - | - | **123** |
| Capital Commitments [2] | 320 | 54 | 61 | 53 | 6 | 2 | **496** |
| Other Long-Term Commitments | 33 | 25 | 18 | 7 | 6 | 10 | **99** |
| Total Payments [3] | 688 | 412 | 587 | 579 | 791 | 9,744 | **12,801** |
| Fixed Price Product Sales | 50 | 52 | 54 | 55 | 3 | - | **214** |

*(1) Certain transportation commitments included are subject to regulatory approval.*
*(2) Includes those commitments related to jointly controlled entities.*
*(3) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.*

| 2011 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | Total |
|---|---|---|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Pipeline Transportation [1] | 143 | 137 | 187 | 311 | 347 | 2,754 | 3,879 |
| Operating Leases (Building Leases) | 71 | 93 | 85 | 80 | 80 | 1,491 | 1,900 |
| Product Purchases | 19 | 18 | 19 | 19 | 6 | - | 81 |
| Capital Commitments [2] | 366 | 98 | 40 | 23 | 22 | 20 | 569 |
| Other Long-Term Commitments | 5 | 4 | 1 | 1 | - | 1 | 12 |
| Total Payments [3] | 604 | 350 | 332 | 434 | 455 | 4,266 | 6,441 |
| Fixed Price Product Sales | 52 | 54 | 56 | 57 | 60 | 3 | 282 |

*(1) Certain transportation commitments included are subject to regulatory approval.*
*(2) Includes those commitments related to jointly controlled entities.*
*(3) Contracts undertaken on behalf of the FCCL Partnership and WRB Refining LP are reflected at Cenovus's 50 percent interest.*

At December 31, 2012, there were outstanding letters of credit aggregating $36 million issued as security for performance under certain contracts (2011 – $17 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 31.

### B) Contingencies

#### *Legal Proceedings*

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

#### *Decommissioning Liabilities*

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recognized a liability of $2,315 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

#### *Income Tax Matters*

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.



Table of Contents



## 34. SUBSEQUENT EVENT

Subsequent to December 31, 2012, Management decided to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The public sales process is expected to be launched in late February 2013. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. Operating results from these properties are included in the Conventional segment.



Table of Contents

# Cenovus Energy Inc.

Supplementary Information – Oil and Gas Activities (unaudited)

For the year Ended December 31, 2012

(Canadian Dollars)

Table of Contents

**DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES TOPIC 932 "EXTRACTIVE ACTIVITIES – OIL AND GAS" (unaudited)**

The following select disclosures of Cenovus Energy Inc.'s ("Cenovus" or the "Company") reserves and other oil and gas information have been prepared in accordance with United States ("U.S.") Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil & Gas" and the U.S. disclosure requirements of the Securities and Exchange Commission ("SEC").

All amounts pertaining to Cenovus's audited Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Unless otherwise noted, all amounts are in millions of Canadian dollars.

**RESERVES DATA**

The SEC Modernization of Oil and Gas Reporting final rules require that proved reserves be estimated using existing economic conditions (constant pricing). Cenovus's results have been calculated using the average of the first-day-of-the-month prices for the prior 12 month period. This same 12 month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Cenovus's share of future production from Canadian reserves to be materially different from that presented.

The reserves estimates included in this supplemental information are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond 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 with respect to royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, all of which may vary considerably from actual results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, royalty payments, 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.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made.

Subsequent to December 31, 2012 no major discovery or other favourable or unfavourable event is believed to have caused a material change in the proved or proved developed reserves as of that date.



Table of Contents

**OIL AND GAS RESERVE INFORMATION**

All of Cenovus's reserves are located in Canada, primarily within the provinces of Alberta and Saskatchewan.

**Net Proved Reserves (Cenovus Share After Royalties)[1)(2)(3)]**
**Average Fiscal-Year Prices**

| | Bitumen (millions of barrels) | Crude Oil and Natural Gas Liquids (millions of barrels) | Natural Gas (billions of cubic feet) |
|---|---|---|---|
| **2011** | | | |
| Beginning of year | 916 | 238 | 1,280 |
| Revisions and improved recovery | 11 | (3) | 28 |
| Extensions and discoveries | 202 | 26 | 51 |
| Purchase of reserves in place | - | - | - |
| Sale of reserves in place | - | - | - |
| Production | (20) | (21) | (240) |

| | | | |
|---|---|---|---|
| End of year | 1,109 | 240 | 1,119 |
| Developed | 128 | 175 | 1,114 |
| Undeveloped | 981 | 65 | 5 |
| Total | 1,109 | 240 | 1,119 |
| **2012** | | | |
| Beginning of year | 1,109 | 240 | 1,119 |
| Revisions and improved recovery | 44 | 13 | (144) |
| Extensions and discoveries | 211 | 27 | 29 |
| Purchase of reserves in place | - | - | 1 |
| Sale of reserves in place | - | - | (40) |
| Production | (30) | (25) | (209) |
| End of year | 1,334 | 255 | 756 |
| Developed | 144 | 185 | 756 |
| Undeveloped | 1,190 | 70 | - |
| Total | 1,334 | 255 | 756 |

**Notes:**

(1) Definitions:
- (a) "Net" reserves are the remaining reserves attributable to Cenovus, after deduction of estimated royalties and including royalty interests.
- (b) "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations, i.e., prices and costs as of the date the estimate is made.
- (c) "Developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods in which the cost or the required equipment is relatively minor compared to the cost of a new well.
- (d) "Undeveloped" reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Estimates of total net proved bitumen, crude oil, natural gas liquids, or natural gas reserves are not filed by Cenovus with any U.S. federal authority or agency other than the SEC.

(3) Natural gas liquids reserves are individually insignificant and have been included with crude oil reserves.



Table of Contents

***Standardized Measure of Discounted Future Net Cash Flows and Changes Therein***

In calculating the standardized measure of discounted future net cash flows, the average of the first-day-of-the-month prices for the prior 12 month period and cost assumptions were applied to Cenovus's annual future production from proved reserves to determine cash inflows. Future production and development costs do not include any cost inflation and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a ten percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for asset retirement obligations and future income taxes.

Cenovus cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of the Cenovus's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of ten percent may not appropriately reflect future interest rates. The computation also excludes values attributable to Cenovus's enhancing the netback price of the Company's proprietary production.

Computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves were based on the following average of the first-day-of-the-month benchmark prices for the twelve month period before the end of the year:

| | Crude Oil | | | Natural Gas | |
|---|---|---|---|---|---|
| | WTI[1] Cushing Oklahoma (US$/bbl) | WCS[2] (C$/bbl) | Edmonton Par (C$/bbl) | Henry Hub Louisiana (US$/MMBtu) | AECO[3] (C$/MMBtu) |
| 2012 | 94.71 | 73.26 | 87.11 | 2.76 | 2.35 |
| 2011 | 96.19 | 77.58 | 96.85 | 4.12 | 3.76 |

**Notes:**

(1) WTI is an abbreviation for West Texas Intermediate

(2) WCS is an abbreviation for Western Canadian Select

(3) AECO is an abbreviation for Alberta Energy Company Hub



Table of Contents

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

| ($ millions) | 2012 | 2011 |
|---|---|---|
| Future cash inflows | 92,383 | 90,320 |
| Less future: | | |
| Production costs | 29,356 | 27,158 |
| Development costs | 12,705 | 9,138 |

| | | |
|---|---|---|
| Asset retirement obligation payments | 842 | 732 |
| Income taxes | 11,410 | 12,424 |
| Future net cash flows | 38,070 | 40,868 |
| Less 10 percent annual discount for estimated timing of cash flows | 23,381 | 25,414 |
| Discounted future net cash flows | 14,689 | 15,454 |

**Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

| ($ millions) | **2012** | **2011** |
|---|---|---|
| Balance, beginning of year | 15,454 | 11,157 |
| Changes resulting from: | | |
| Sales of oil and gas produced during the period | (3,169) | (2,881) |
| Discoveries and extensions, net of related costs | 2,668 | 2,364 |
| Purchases of proved reserves in place | 7 | 7 |
| Sales of proved reserves in place | (85) | - |
| Net change in prices and production costs | (1,911) | 4,330 |
| Revisions to quantity estimates | 431 | 142 |
| Accretion of discount | 2,002 | 1,447 |
| Previously estimated development costs incurred net of change in future development costs | (1,055) | (806) |
| Other | 207 | 942 |
| Net change in income taxes | 140 | (1,248) |
| Balance, end of year | 14,689 | 15,454 |

**Results of Operations**

| ($ millions) | **2012** | **2011** |
|---|---|---|
| Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management | 4,020 | 3,784 |
| Intersegment sales | 283 | 59 |
| | 4,303 | 3,843 |
| Less: | | |
| Operating costs, production and mineral taxes, and accretion of decommissioning liabilities | 1,218 | 1,035 |
| Depreciation, depletion and amortization | 1,387 | 1,125 |
| Goodwill impairment | 393 | - |
| Exploration expense | 68 | - |
| Operating income | 1,237 | 1,683 |
| Income taxes | 411 | 449 |
| Results of operations | 826 | 1,234 |



Table of Contents

**Capitalized Costs**

| ($ millions) | **2012** | **2011** |
|---|---|---|
| Proved oil and gas properties | 27,241 | 24,052 |
| Unproved oil and gas properties | 1,285 | 880 |
| Total capital cost | 28,526 | 24,932 |
| Accumulated depreciation, depletion and amortization | 14,548 | 13,160 |
| Net capitalized costs | 13,978 | 11,772 |

**Costs Incurred**

| ($ millions) | **2012** | **2011** |
|---|---|---|
| Acquisitions | | |
| - Unproved | 90 | 69 |
| - Proved | 24 | - |
| Total acquisitions | 114 | 69 |
| Exploration costs | 424 | 240 |
| Development costs | 2,589 | 1,935 |
| Total costs incurred | 3,127 | 2,244 |

## ADDITIONAL DISCLOSURE

**Certifications and Disclosure Regarding Controls and Procedures.**

(a) Certifications. See Exhibits 99.1, 99.2, 99.3 and 99.4 to this annual report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant's fiscal year ended December 31, 2012, an evaluation of the effectiveness of the registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (the "Commission") rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the "Report of Management" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2012, filed as part of this annual report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Auditor's Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2012, filed as part of this annual report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2012, there was no change in the registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

**Notices Pursuant to Regulation BTR.**

None.

**Audit Committee Financial Expert.**

The registrant's board of directors has determined that Colin Taylor, a member of the registrant's audit committee, qualifies as an "audit committee financial expert" (as such term is defined in paragraph (8) of General Instruction B to Form 40-F), and is "independent" as that term is defined in the rules of the New York Stock Exchange.

**Code of Ethics.**

The registrant has adopted a "code of ethics" (as that term is defined in paragraph (9) of general Instruction B to Form 40-F), entitled the "Code of Business Conduct & Ethics", that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

The Code of Business Conduct & Ethics is available for viewing on the registrant's website at www.cenovus.com, and is available in print to any person without charge, upon request. Requests for copies of the Code of Business Conduct & Ethics should be made by contacting: Kerry D. Dyte, Executive Vice-President, General Counsel & Corporate Secretary, Cenovus Energy Inc., 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6. Alternatively, requests for a copy of the Code of Business Conduct & Ethics may be made by contacting the registrant's Corporate Secretarial Department at (403) 766-2000 (Fax: (403) 766-7600).





Since the adoption of the Code of Business Conduct & Ethics, there have not been any waivers, including implicit waivers, granted from any provision of the Code of Business Conduct & Ethics. There were no amendments to the Code of Business Conduct & Ethics in the fiscal year ended December 31, 2012.

**Principal Accountant Fees and Services.**

The required disclosure is included under the heading "Audit Committee – External Auditor Service Fees" in the registrant's Annual Information Form for the fiscal year ended December 31, 2012, filed as part of this annual report on Form 40-F.

**Pre-Approval Policies and Procedures.**

The required disclosure is included under the heading "Audit Committee Information – Pre-Approval Policies and Procedures" in the registrant's Annual Information Form for the fiscal year ended December 31, 2012, filed as part of this annual report on Form 40-F.

**Off-Balance Sheet Arrangements.**

The registrant does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

**Tabular Disclosure of Contractual Obligations.**

The required disclosure is included under the heading "Contractual Obligations and Contingencies" in the registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2012, filed as part of this annual report on Form 40-F.

**Identification of the Audit Committee.**

The registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, Valerie A. A. Nielsen and Colin Taylor.

**Mine Safety Disclosure.**

Not applicable.



Table of Contents

**UNDERTAKING AND CONSENT TO SERVICE OF PROCESS**

**A. Undertaking**

The registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

**B. Consent to Service of Process**

(1) The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.



Table of Contents

**SIGNATURES**

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: February 20, 2013

**CENOVUS ENERGY INC.**

By: /s/ Ivor M. Ruste
Name: Ivor M. Ruste
Title: Executive Vice-President & Chief Financial Officer



Table of Contents

**EXHIBIT INDEX**

| Exhibits | Documents |
|---|---|
| 99.1 | Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 |
| 99.2 | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934 |
| 99.3 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350 |
| 99.4 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350 |
| 99.5 | Consent of PricewaterhouseCoopers LLP |
| 99.6 | Consent of McDaniel & Associates Consultants Ltd. |
| 99.7 | Consent of GLJ Petroleum Consultants Ltd. |

Exhibit 99.1

**Certification of Chief Executive Officer**
**Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934**

I, Brian C. Ferguson, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 20, 2013

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.2

**Certification of Chief Financial Officer**
**Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934**

I, Ivor M. Ruste, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 20, 2013

/s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.3

**Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes Oxley Act of 2002**

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40-F for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian C. Ferguson, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 20, 2013

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer

Exhibit 99.4

**Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40-F for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ivor M. Ruste, Executive Vice-President & Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 20, 2013

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

Exhibit 99.5

## CONSENT OF PRICEWATERHOUSECOOPERS LLP

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2012 of Cenovus Energy Inc. of our report dated February 13, 2013, relating to the Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2012 and December 31, 2011 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years in the period ended December 31, 2012 and the related notes and to the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as at December 31, 2012, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-10 (File No. 333-181728) of Cenovus Energy Inc. of our report dated February 13, 2013 referred to above. We also consent to reference to PricewaterhouseCoopers LLP under the heading "Interests of Experts," which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
February 20, 2013

Exhibit 99.6

**CONSENT OF INDEPENDENT PETROLEUM ENGINEER**

We hereby consent to the use and reference to our name and reports evaluating (i) a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2012, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2012 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-10 (File No. 333-181728), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ P.A. Welch
P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 20, 2013

Exhibit 99.7

**CONSENT OF INDEPENDENT PETROLEUM ENGINEER**

We hereby consent to the use and reference to our name and report evaluating a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2012 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-10 (File No. 333-181728), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Keith M. Braaten

Keith M. Braaten, P. Eng.
President & CEO

Calgary, Alberta
February 20, 2013