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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, 2011 **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))

4000, 421-7th Avenue S.W.
Calgary, Alberta, Canada T2P 4K9
(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)

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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:

754,499,336

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: Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-9 (File No. 333-167876).

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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, 2011.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2011.

(c) Consolidated Financial Statements of Cenovus Energy Inc. as at December 31, 2011.

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cenovus ENERGY

CENOVUS ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2011

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FORWARD-LOOKING INFORMATION

This Annual Information Form (“AIF”) contains forward-looking statements and other information (collectively “forward-looking information”) about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. This forward-looking information is identified by words such as “anticipate”, “believe”, “expect”, “plan”, “forecast”, “target”, “project”, “could”, “focus”, “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 our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted earnings before interest, taxes, depreciation and amortization and debt to capitalization; our ability to access external sources of debt and equity capital; success of our hedging strategies; accuracy of reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with ConocoPhillips (or any successor thereof) 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 manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; 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 locations 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.

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CORPORATE STRUCTURE

Cenovus Energy Inc. was formed under the *Canada Business Corporations Act* ("CBCA") by amalgamation of 7050372 Canada Inc. 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 Canada Inc., 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 #4000, 421 – 7 Avenue S.W., Calgary, Alberta, Canada T2P 4K9.

Intercorporate Relationships

The following table summarizes our principal subsidiaries and partnerships at December 31, 2011:

Subsidiaries & Partnerships	Percentage Owned[1]	Jurisdiction of Incorporation, Continuance, Formation or Organization
Cenovus FCCL Ltd.	100	Alberta
Cenovus US Refinery Holdings[2]	100	Delaware
FCCL Partnership ("FCCL")[3]	50	Alberta
WRB Refining LP ("WRB")[4]	50	Delaware

Notes:
(1) Includes direct and indirect ownership.
(2) A Delaware partnership.
(3) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL Partnership.
(4) Cenovus interest held indirectly through Cenovus US Refinery Holdings.

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, 2011.

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**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. 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.

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- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **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 ConocoPhillips. 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:

2011

- In the second quarter, we updated our 10 year strategic plan, identifying oil sands 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, which will continue through the first quarter of 2012, have been successful to date and have resulted in a five percent increase to clean product yield. Upon completion of testing, the Wood River Refinery's total processing capability of heavy crude oil will be 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 a 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.

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- 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

is 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.

2009

- In the first quarter, two new expansion phases at Foster Creek were commissioned. Phases D and E added gross capacity of 60,000 bbls/d of bitumen, increasing gross production capacity of Foster Creek to approximately 120,000 bbls/d of bitumen.
- In the second quarter, a joint regulatory application for Foster Creek phases F, G and H was submitted to the ERCB and Alberta Environment.
- In the fourth quarter, FCCL sanctioned the next phase, phase D, of expansion at Christina Lake, which is expected to increase gross production capacity by 40,000 bbls/d of bitumen in 2013.
- In the fourth quarter, a joint regulatory application for Christina Lake phases E, F and G was submitted to the ERCB and Alberta Environment. Each phase is expected to increase gross production capacity by 40,000 bbls/d of bitumen.
- On December 1, 2009, we began independent operations as a publicly traded company having completed the Arrangement with Encana. In connection with the Arrangement, Encana shareholders received one Cenovus common share and one new Encana common share for each Encana common share held.

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NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our upstream and refining assets as at December 31, 2011.



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Overview

All of our reserves and production are located in Canada, primarily within the provinces of Alberta and Saskatchewan. At December 31, 2011, we had a land base of approximately 7.4 million net acres and Company Interest Before Royalties proved reserves of approximately 1,455 million barrels of bitumen, 175 million barrels of heavy crude oil, 115 million barrels of light and medium crude oil and NGLs and 1,203 billion cubic feet of natural gas. The estimated proved reserves life index based on working interest production at December 31, 2011 was approximately 22 years. We also had Company Interest Before Royalties probable reserves of approximately 490 million barrels of bitumen, 109 million barrels of heavy crude oil, 51 million barrels of light and medium crude oil and NGLs and 391 billion cubic feet of natural gas at December 31, 2011.

The following narrative describes our operations in greater detail.

Oil Sands

Oil Sands includes our producing bitumen assets at Foster Creek and Christina Lake, as well as heavy crude oil assets at Pelican Lake, new resource play assets including Narrows Lake, Grand Rapids and Telephone Lake, and 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, through the FCCL Partnership ("FCCL").

FCCL owns the Foster Creek, Christina Lake and Narrows Lake properties, as well as other bitumen interests. 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 2011, our Oil Sands capital investment was $1,415 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 218,000 bbls/d of bitumen following the completion of Christina Lake phase D, which is expected in the fourth quarter of 2012. Pelican Lake capital investment for 2011 was primarily related to infill drilling to progress polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance capital. Oil Sands also continued to assess the potential of our new resource play assets during 2011 with our large stratigraphic test well program.

Plans for 2012 include the continued development of expansion phases at both Foster Creek and Christina Lake, additional capital investment at our Pelican Lake property, the continuation of an active stratigraphic test well program on our new resource play assets and progressing pilot projects at our Grand Rapids and Telephone Lake properties.

At December 31, 2011, we held bitumen rights of approximately 1,227,000 gross acres (889,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 544,000 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, 2011:

Landholdings – Oil Sands	**Developed**		**Undeveloped**		**Total**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Foster Creek	12	6	130	65	142	71	50%
Christina Lake	6	3	33	16	39	19	50%
Pelican Lake	105	105	287	283	392	388	99%
Telephone Lake	4	4	142	142	146	146	100%
Athabasca	445	370	426	355	871	725	83%
Other	49	31	956	691	1,005	722	72%
Total	621	519	1,974	1,552	2,595	2,071	80%

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The following table sets forth 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)	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Foster Creek	54,868	51,147	-	-	54,868	51,147
Christina Lake	11,665	7,898	-	-	11,665	7,898
Pelican Lake	20,424	22,966	-	-	20,424	22,966
Athabasca	-	-	34	40	5,667	6,667
Other	-	-	3	3	500	500
Total	86,957	82,011	37	43	93,124	89,178

The following table summarizes our interests in producing wells at December 31, 2011. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2011:

Producing Wells – Oil Sands	**Producing Oil Wells**		**Producing Gas Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Foster Creek	204	102	-	-	204	102
Christina Lake	38	19	-	-	38	19
Pelican Lake	444	444	5	5	449	449
Athabasca	-	-	416	394	416	394
Other	1	1	17	17	18	18
Total	687	566	438	416	1,125	982

Foster Creek

We have a 50 percent interest in Foster Creek, an oil sands property in northeast Alberta that uses steam-assisted gravity drainage ("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.

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 2011, we drilled 10 wells (2010 – 20 wells) using this technology, and at December 31, 2011 there were 41 wells of this type producing.

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. The phase C expansion, completed in 2011, increased gross production capacity to approximately 58,000 bbls/d of bitumen. In 2011, we received regulatory approval for phases E, F and G which are expected to add a total of approximately 140,000 bbls/d of gross bitumen production capacity. In the fourth quarter of 2011, we applied for an amendment to our existing application to add cogeneration facilities at Christina Lake and increasing total gross production capacity by 10,000 bbls/d at each of phase F and phase G. In 2011, we drilled three wells (2010 – four wells) at Christina Lake using our Wedge Well™ technology and at December 31, 2011 there were four wells of this type producing.

Several innovations to SAGD technology have been undertaken at Christina Lake over the past several years. One major project that started in 2009 is a new Solvent Aided Process ("SAP") pilot. This SAP pilot utilizes a mixture of steam and solvent to enhance recovery of the bitumen by reducing the steam to oil ratio and increasing the overall recovery of the bitumen. Business cases are currently being evaluated for the potential use of this technology in the

Christina Lake and Narrows Lake development plans.

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In 2011, we 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 and EIA was filed. The project includes gross production capacity of 130,000 bbls/d of bitumen to be developed in up to three phases, with the first phase expected to have production capacity of approximately 40,000 bbls/d of bitumen. Our submitted application includes the option to implement the SAP technology at Narrows Lake which would allow the project to be developed in two phases of 65,000 bbls/d, rather than three phases. The project is expected to begin producing in 2016, subject to receiving regulatory approval.

Pelican Lake

Using a pattern, 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 2011, our capital investment primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance programs. In 2011 we drilled 31 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.

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. During 2011, we executed a pilot project at Grand Rapids which will continue to be operated during 2012. 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.

Our Telephone Lake property is located in the Borealis Region in northeast Alberta. A joint application and EIA was submitted in 2007 to the ERCB and Alberta Environment for the development of the property, including the construction of a facility with bitumen production capacity of 35,000 bbls/d. In the fourth quarter of 2011, we submitted a revised joint application and EIA, which increases the planned production capacity to 90,000 bbls/d. Portions of the Telephone Lake reservoir are overlain with non-saline water. To improve SAGD performance, this water should be removed in advance of SAGD operations. In the first quarter of 2012, a significant test will be carried out to dewater a confined area and the results will be monitored throughout the year.

The Steepbank and East McMurray properties are also located in the Borealis Region, southwest of Telephone Lake. An active exploration program is being carried out at these properties. In 2011, 44 stratigraphic wells were drilled and 210 km of 2D seismic was shot. A comparable sized program is underway in 2012.

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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 21 million cubic feet per day in 2011 (2010 - 23 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 dependant on natural gas prices.

Conventional

We have conventional crude oil and natural gas operations in Alberta and Saskatchewan. Conventional operations include crude oil properties in southern Alberta, the Weyburn CO_2 enhanced oil recovery project as well as our Bakken and Lower Shaunavon properties.

At December 31, 2011, we had an established land position of approximately 5.5 million gross acres (5.3 million net acres), of which approximately 3.7 million gross acres (3.6 million net acres) are developed. The mineral rights on approximately 59 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 2011, our Conventional capital investment was $788 million and primarily focused on crude oil properties, including drilling and facility work at Weyburn and in southern Alberta as well as drilling in the Bakken and Lower Shaunavon areas.

Plans for 2012 include additional capital investment in our Weyburn, Bakken and Lower Shaunavon properties as well as our Alberta crude oil properties.

The investment is expected to include additional drilling, well optimizations, well recompletions and investment in facility infrastructure necessary for continued development of our assets.

The following table summarizes our landholdings at December 31, 2011:

Landholdings – Conventional	Developed		Undeveloped		Total		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Alberta							
Suffield	915	906	106	103	1,021	1,009	99%
Brooks North	571	569	8	8	579	577	100%
Langevin	730	691	244	226	974	917	94%
Drumheller	402	390	45	42	447	432	97%
Wainwright	354	332	208	203	562	535	95%
Boyer	590	558	204	164	794	722	91%
Saskatchewan							
Weyburn	108	95	368	348	476	443	93%
Shaunavon / Bakken	26	24	370	367	396	391	99%
Other	9	6	19	19	28	25	87%
Manitoba	3	3	261	261	264	264	100%
Total	3,708	3,574	1,833	1,741	5,541	5,315	96%

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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)	2011	2010	2011	2010	2011	2010
Alberta						
Suffield	11,505	12,742	182	200	41,838	46,075
Brooks North	2,064	1,637	236	240	41,397	41,637
Langevin	7,361	7,728	118	152	27,028	33,062
Drumheller	2,298	2,109	61	72	12,465	14,109
Wainwright	4,251	4,414	-	3	4,251	4,914
Boyer	9	13	22	24	3,676	4,013
Saskatchewan						
Weyburn	16,178	16,537	-	-	16,178	16,537
Shaunavon / Bakken	3,616	1,996	-	3	3,616	2,496
Total	47,282	47,176	619	694	150,449	162,843

The following table summarizes our interests in producing wells at December 31, 2011. These figures exclude wells which were capable of producing, but that were not producing, at December 31, 2011:

Producing Wells – Conventional	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Alberta						
Suffield	746	746	10,649	10,631	11,395	11,377
Brooks North	111	111	7,520	7,411	7,631	7,522
Langevin	243	240	4,842	4,826	5,085	5,066
Drumheller	169	165	1,615	1,555	1,784	1,720
Wainwright	442	400	19	5	461	406
Boyer	7	1	1,079	1,078	1,086	1,079
Saskatchewan						
Weyburn	712	448	-	-	712	448
Shaunavon / Bakken	96	93	-	-	96	93
Total	2,526	2,204	25,724	25,506	28,250	27,710

Crude Oil Properties

We hold interests in multiple zones in the Suffield, Brooks North, Langevin, Drumheller, and Wainwright areas in southern Alberta with a mix of medium and heavy crude oil production. Development in these areas focuses on infill drilling, optimization of existing wells and other specialized oil recovery methods. We operate water handling facilities to effectively manage oil production.

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 and 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, 2011, approximately 87 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 18 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.

In 2011, we continued developing our medium and light crude oil prospects in the Bakken and Lower Shaunavon zones in Saskatchewan, where we drilled 81 wells and increased production to approximately 3,581 bbls/d of crude oil. 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	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Alberta						
Suffield	45	43	-	-	11,484	12,717
Brooks North	42	41	1,898	1,458	-	-
Langevin	68	22	7,172	7,529	-	-
Drumheller	49	30	1,617	1,403	-	-
Wainwright	29	3	67	452	4,173	3,942
Boyer	-	-	9	12	-	-
Saskatchewan						
Weyburn	6	3	16,180	16,534	-	-
Shaunavon / Bakken	81	36	3,581	1,958	-	-
Other	5	2	-	-	-	-
Total	325	180	30,524	29,346	15,657	16,659

Natural Gas Properties

We hold interests in multiple zones in the Suffield, Brooks North, Langevin and Drumheller areas in southern 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	**2011**	**2010**	**2011**	**2010**
Suffield	-	292	182	200
Brooks North	65	149	236	240
Langevin	-	24	118	152
Drumheller	-	29	61	72
Other	-	1	22	30
Total	65	495	619	694

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. On October 6, 2008, pursuant to the Canadian *Environmental Assessment Act*, a joint review panel ("JRP"), made up of provincial and federal regulators, heard our application for a shallow gas infill development in the National Wildlife Area ("NWA") at CFB Suffield. The hearing was completed in late October 2008. On January 27, 2009, the JRP released its recommendations, concluding that the proposed project could proceed provided two key pre-conditions were met: first, critical habitat assessments for certain specific species of plants and animals must be finalized by Environment Canada within the NWA; and second, the role of the Suffield Environmental Advisory Committee ("SEAC") must be clarified by the parties to the surface access agreement, and SEAC must be resourced adequately to provide proper environmental oversight of the project. The JRP also concluded that other mitigations and recommendations should be followed once the two key pre-conditions were met. We are working with necessary interested parties to proceed with this project.

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

We plan to 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 Refining LP ("WRB") we have a 50 percent ownership interest in both the Wood River and Borger Refineries located in Roxana, Illinois and Borger, Texas respectively. ConocoPhillips is the operator and managing partner of WRB. WRB has a management committee, which is composed of three Cenovus representatives and three ConocoPhillips representatives, with each company holding equal voting rights. Throughout 2011, on a 100 percent basis, our refineries had a capacity of approximately 452,000 bbls/d of crude oil and approximately 45,000 bbls/d of NGLs, including processing capability of up to 145,000 bbls/d of heavy crude oil. As plant test runs proceed, maximum demonstrated refining capacity increases attributable to the CORE project at the Wood River Refinery, including expanded coking and heavy crude oil processing capabilities, will be reflected in our 2012 operations.

Wood River Refinery

Throughout 2011, the Wood River Refinery had a processing capability of approximately 306,000 bbls/d, including approximately 110,000 bbls/d of heavy crude oil. It 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 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.

Test runs of the CORE project, which will continue through the first quarter of 2012, have been successful to date and have resulted in a five percent increase to clean product yield. Upon completion of testing, the Wood River Refinery's total processing capability of heavy crude oil will be 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.

Borger Refinery

At December 31, 2011, the Borger Refinery had a 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. It processes mainly medium and heavy high-sulphur crude oil, and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the U.S. Mid-Continent.

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

Refinery Operations[1]	**2011**	**2010**
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	401	386
Crude Utilization (%)	89	86
Refined Products (Mbbls/d)		
Gasoline	207	204
Distillates	132	123
Other	80	78
Total	419	405

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.

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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, 2011.

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 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.

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 coalbed methane ("CBM") reserves annually. McDaniel evaluated approximately 95 percent of our total proved reserves, located throughout Alberta and Saskatchewan, and GLJ evaluated approximately five percent of our total proved reserves, located at Boyer and 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.

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The reserves data and other oil and gas information contained in this AIF is dated February 13, 2012, with an effective date of December 31, 2011. McDaniel's preparation date of the information is February 13, 2012, and GLJ's preparation date is January 9, 2012.

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, facilities and 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, 2011, approximately 2.4 million acres throughout southeastern Alberta and southern Saskatchewan and Manitoba were leased out to third parties. In accordance with NI 51-101, only the After Royalties volumes presented herein include reserves associated with this Royalty Interest Production ("Royalty Interest Reserves").

Summary of Company Interest Oil and Gas Reserves at December 31, 2011
(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	162	105	82	1,145
Developed Non-Producing	6	15	8	34
Undeveloped	1,287	55	25	24
Total Proved Reserves	1,455	175	115	1,203
Probable Reserves	490	109	51	391
Total Proved plus Probable Reserves	1,945	284	166	1,594

After Royalties[2]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	121	86	70	1,152
Developed Non-Producing	5	12	5	34
Undeveloped	953	44	20	23
Total Proved Reserves	1,079	142	95	1,209
Probable Reserves	357	81	42	375
Total Proved plus Probable Reserves	1,436	223	137	1,584

Royalty Interest

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	-	2	4	45
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved Reserves	-	2	4	45
Probable Reserves	-	-	2	15
Total Proved plus Probable Reserves	-	2	6	60

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

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Summary of Net Present Value of Future Net Revenue at December 31, 2011
(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	16,704	13,539	11,404	9,883	8,747	24.28
Developed Non-Producing	1,119	760	568	452	374	20.98

Undeveloped	45,721	19,864	10,121	5,677	3,352	9.91
Total Proved Reserves	63,544	34,163	22,093	16,012	12,473	14.56
Probable Reserves	25,192	12,571	6,881	4,169	2,746	12.68
Total Proved plus Probable Reserves	88,736	46,734	28,974	20,181	15,219	14.06

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

After Income Taxes[1]

	Discounted at %/year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	13,094	10,668	9,017	7,837	6,954
Developed Non-Producing	834	567	425	340	282
Undeveloped	34,237	14,747	7,434	4,110	2,379
Total Proved Reserves	48,165	25,982	16,876	12,287	9,615
Probable Reserves	18,705	9,294	5,057	3,042	1,989
Total Proved plus Probable Reserves	66,870	35,276	21,933	15,329	11,604

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, 2011.

Total Future Net Revenue (undiscounted) at December 31, 2011
(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	151,861	35,574	40,130	11,563	1,050	63,544	15,379	48,165
Proved plus Probable Reserves	209,399	49,813	53,882	15,769	1,199	88,736	21,866	66,870

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.

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Future Net Revenue by Production Group at December 31, 2011
(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	13,897	12.88
	Heavy Oil	3,008	21.19
	Light and Medium Crude Oil and NGLs	2,986	31.30
	Natural Gas	2,202	10.94
	Total	22,093	14.56
Proved plus Probable Reserves	Bitumen	17,490	12.18
	Heavy Oil	4,533	20.31
	Light and Medium Crude Oil and NGLs	4,053	29.51
	Natural Gas	2,898	10.98
	Total	28,974	14.06

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.

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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.

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, 2012 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2012. For historical prices realized during 2011, 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)
2012	97.50	99.00	91.00	74.00	80.50	3.50	2.0	0.975
2013	97.50	99.00	91.00	74.00	80.50	4.20	2.0	0.975
2014	100.00	101.50	93.30	75.90	82.50	4.70	2.0	0.975
2015	100.80	102.30	94.10	76.50	83.20	5.10	2.0	0.975
2016	101.70	103.20	94.90	77.10	83.90	5.55	2.0	0.975
2017	102.70	104.20	95.80	77.90	84.70	5.90	2.0	0.975
2018	103.60	105.10	96.60	78.60	85.50	6.25	2.0	0.975
2019	104.50	106.00	97.50	79.20	86.20	6.45	2.0	0.975
2020	105.40	106.90	98.30	79.90	86.90	6.70	2.0	0.975
2021	107.60	109.20	100.30	81.60	88.70	6.85	2.0	0.975
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.975

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)	2012	2013	2014	2015	2016	Remainder	Total
Proved Reserves	1,413	928	527	595	334	7,766	11,563
Proved plus Probable Reserves	1,582	1,247	859	854	518	10,709	15,769

We believe that internally generated cash flows, existing credit facilities and access to capital markets will be sufficient to fund our future development costs. However, there can be no guarantee that the necessary funds will be available or that we will allocate funding to develop all of our reserves. Failure to develop those reserves would have a negative impact on our future net revenue.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce future net revenue depending upon the funding sources utilized. We do not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of our Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2011, 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, 2010	1,154	169	111	1,390
Extensions and Improved Recovery	256	16	13	50
Discoveries	-	-	-	-
Technical Revisions	69	2	1	29
Economic Factors	-	1	-	(28)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production[(1)]	(24)	(13)	(10)	(238)
December 31, 2011	1,455	175	115	1,203

Probable				
	Bitumen (MMbbls)	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2010	523	97	49	410
Extensions and Improved Recovery	32	14	3	11
Discoveries	-	-	-	-
Technical Revisions	(65)	(2)	(1)	(27)
Economic Factors	-	-	-	(3)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production[(1)]	-	-	-	-
December 31, 2011	490	109	51	391

Proved plus Probable				
	Bitumen (MMbbls)	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2010	1,677	266	160	1,800
Extensions and Improved Recovery	288	30	16	61
Discoveries	-	-	-	-
Technical Revisions	4	-	-	2
Economic Factors	-	1	-	(31)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production[(1)]	(24)	(13)	(10)	(238)
December 31, 2011	1,945	284	166	1,594

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.

Proved and proved plus probable bitumen reserves increased by approximately 26 and 16 percent respectively. Increases at Christina Lake were primarily a result of receiving regulatory approval to expand the development area and from positive delineation results. Increases at Foster Creek were primarily due to positive revisions from delineation drilling, increased recovery resulting from wells using our Wedge Well™ technology and improved steam chamber recovery.

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Proved heavy oil reserves increased by approximately four percent primarily as a result of expanding polymer flood areas and their successful performance in the Greater Pelican Region. Probable heavy oil reserves increased by approximately 12 percent also based on expansion and performance. Proved plus probable reserves increased by approximately seven percent.

Proved light and medium oil and NGLs reserves increased by approximately four percent, primarily as a result of expanding waterflood and CO2 flood areas and their successful performance at Weyburn. Probable light and medium oil and NGLs reserves increased by approximately four percent as a result of continued strong performance. Overall, proved plus probable reserves increased by approximately four percent.

Proved natural gas reserves declined by approximately 13 percent as extensions and technical revisions did not offset production. Probable natural gas reserves and proved plus probable reserves declined by approximately five percent and 11 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 43 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	623	560	47	45	38	29	272	150
2009	190	734	8	46	7	28	10	35
2010	295	1,008	5	45	5	27	18	36
2011	325	1,287	13	55	3	25	-	24

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	628	625	-(1)	-(1)	-(1)	-(1)	-(1)	-(1)
2009	5	467	43	43	26	26	38	38
2010	171	506	-	37	2	21	16	30
2011	113	467	14	47	1	22	-	35

Note:
(1) Historical information is not available.

Development of Proved Undeveloped Reserves

Bitumen

At the end of 2011, we had proved undeveloped bitumen reserves of 1,287 million barrels Before Royalties, or approximately 88 percent of our total proved bitumen reserves. Of our 490 million barrels of probable bitumen reserves, 467 million barrels, or approximately 95 percent are undeveloped. For this evaluation, it is assumed that these reserves 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 wells 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 standard for sufficient drilling is a minimum eight 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.

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Development 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 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 43 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 undeveloped reserves is projected to continue for well over 40 years, with drilling of supplementary wells taking place over the next seven years, and CO_2 flood advancement continuing many years beyond that. At Pelican Lake, investment in undeveloped reserves is projected to continue for eight years, with a combination of infill drilling and polymer flood advancement.

Significant Factors or Uncertainties Affecting Reserves Data

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

Contingent and Prospective Resources

We retain McDaniel to evaluate and prepare reports on all of our contingent and prospective bitumen resources. The evaluations by McDaniel are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that McDaniel is in receipt of all relevant information. Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. The 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.

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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. All of Cenovus's bitumen contingent resources were evaluated using the same economic assumptions that were used for the 2011 reserves evaluation.

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.

At Christina Lake and Foster Creek 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 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.

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.

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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 confidence level 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 at the low end of the estimate range have the highest degree of certainty - a 90 percent confidence level – 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 at the high end of the estimate range have a lower degree of certainty - a 10 percent confidence level - that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated on a project level. The high and low estimates are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. The aggregated low estimate results shown may have a higher level of confidence than the individual projects, and the aggregated high estimate results shown may have a lower level of confidence than the individual projects.

Economic Contingent and Prospective Resources		
Company Interest Before Royalties, Billions of barrels	**December 31, 2011**	**December 31, 2010**
Economic Contingent Resources[1]		
Low Estimate	6.0	4.4
Best Estimate	8.2	6.1
High Estimate	10.8	8.0
Prospective Resources[2]		
Low Estimate	5.7	7.3
Best Estimate	10.0	12.3
High Estimate	17.9	21.7

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.

Best estimate economic contingent resources increased 2.1 billion barrels or 34 percent compared to 2010. This increase is primarily due to successful stratigraphic well drilling resulting in the conversion of prospective resources to contingent resources, and to positive technical revisions to volumetric and recovery factor estimates.

Best estimate prospective resources declined 2.3 billion barrels or approximately 19 percent compared to 2010, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic well drilling.

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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, 2010	1.677	6.1	12.3
Transfers between Categories			
Additions from other resource categories	0.142	2.0	(2.0)
Reductions to other resource categories	-	(0.1)	-
Additions and Revisions Net of Transfers	0.150	0.2	(0.3)
Net Acquisitions and Dispositions	-	-	-
Production	(0.024)	-	-
December 31, 2011	1.945	8.2	10.0

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, approval for expansion of the Christina Lake development area 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.

Bitumen reserves and resources increased in part because of improvements in SAGD performance at our Foster Creek and Christina Lake properties resulting from improved operating performance and the use of wells drilled using our Wedge Well™ technology. Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to continue to improve overall recovery from our bitumen assets as technology develops.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following tables summarize our interests in producing and non-producing wells, at December 31, 2011:

Producing Wells[1][2]

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta						
Oil Sands	687	566	438	416	1,125	982
Conventional	1,718	1,663	25,724	25,506	27,442	27,169
Total Alberta	2,405	2,229	26,162	25,922	28,567	28,151
Saskatchewan	808	541	-	-	808	541
Total	3,213	2,770	26,162	25,922	29,375	28,692

Notes:
(1) Cenovus also has varying royalty interests in 7,076 natural gas wells and 3,495 crude oil wells which are producing.
(2) Includes wells containing multiple completions as follows: 22,836 gross natural gas wells (22,633 net wells) and 1,227 gross crude oil wells (1,119 net wells).

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Non-Producing Wells[1]

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta						
Oil Sands	81	67	615	564	696	631
Conventional	734	709	879	857	1,613	1,566
Total Alberta	815	776	1,494	1,421	2,309	2,197
Saskatchewan	137	100	38	38	175	138
Total	952	876	1,532	1,459	2,484	2,335

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
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
2009:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	4	4	-	-	-	-	4	4	8	12	4
Total Canada	4	4	-	-	-	-	4	4	8	12	4

Development Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
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
2009:											
Oil Sands	50	29	8	8	8	8	66	45	10	76	45
Conventional	102	101	555	502	2	2	659	605	261	920	605

Total Canada	152	130	563	510	10	10	725	650	271	996	650

During the year ended December 31, 2011, Oil Sands drilled 480 gross stratigraphic test wells (344 net wells) and Conventional drilled 11 gross stratigraphic test wells (11 net wells).

During the year ended December 31, 2011, Oil Sands drilled 62 gross service wells (50 net wells) and Conventional drilled 30 gross service wells (20 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.

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Interest in Material Properties

The following table summarizes our landholdings at December 31, 2011:

Landholdings	**Developed**		**Undeveloped[1]**		**Total[2]**	
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta:						
Oil Sands						
– Crown[3]	621	519	1,974	1,552	2,595	2,071
Conventional						
– Fee[4]	1,936	1,936	436	436	2,372	2,372
– Crown[3]	1,567	1,461	350	283	1,917	1,744
– Freehold[5]	59	49	29	27	88	76
Total Alberta	4,183	3,965	2,789	2,298	6,972	6,263
Saskatchewan:						
Conventional						
– Fee[4]	75	75	431	431	506	506
– Crown[3]	54	40	310	289	364	329
– Freehold[5]	14	10	16	14	30	24
Total Saskatchewan	143	125	757	734	900	859
Manitoba:						
Conventional – Fee[4]	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,329	4,093	3,807	3,293	8,136	7,386

Notes:
(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.
(2) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.
(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which we have purchased a working interest lease.
(4) Fee lands are those lands in which we have a fee simple interest in the mineral rights and have either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands summary includes all freehold titles owned by us that have one or more zones that remain unleased or available for development.
(5) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

Properties With No Attributed Reserves

We have approximately 5.4 million gross acres (4.8 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 31,000 net acres that could potentially expire by December 31, 2012, 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 $599 million, discounted at 10 percent) at December 31, 2011, of which we expect to pay approximately $79 million in the next three financial years. We expect to incur these costs on approximately 34,000 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of our proved reserves, approximately $1 billion has been deducted in estimating the future net revenue, which only represents our abandonment obligations for wells within reserves.

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Tax Horizon

We expect to pay income tax in 2012.

Costs Incurred

($ millions)	2011
Acquisitions	
– Unproved	69
– Proved	-
Total acquisitions	69
Exploration costs	240
Development costs	1,935
Total costs incurred	2,244

Forward Contracts

We may use financial derivatives to manage our exposure to fluctuations in commodity prices. A description of such instruments is provided in the notes to our annual audited Consolidated Financial Statements for the year ended December 31, 2011.

Production Estimates

The following table summarizes the estimated 2012 average daily volume of Company Interest Before Royalties and Royalty Interest Production reflected in the reserves reports for all properties held on December 31, 2011 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.

2012 Estimated Production		
Forecast Prices and Costs	**Proved**	**Proved plus Probable**
Bitumen (bbls/d)[1]	80,554	81,427
Light and Medium Crude Oil (bbls/d)	31,623	33,951
Heavy Oil (bbls/d)	39,301	42,423
Natural Gas (MMcf/d)	567	590
Natural Gas Liquids (bbls/d)	648	699
Company Interest Before Royalties Production (BOE/d)	246,626	256,900
Royalty Interest Production (BOE/d)	7,197	7,701
Total Company Interest Before Royalties Plus Royalty Interest Production (BOE/d)	253,823	264,601

Note:
(1) Includes Foster Creek production of 54,925 bbls/d for both Proved and Proved plus Probable.

Production History

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.

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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.

Average Before Royalties + Royalty Interest Daily Production Volumes - 2009					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	37,725	47,017	40,367	34,729	28,554
Christina Lake (Bitumen)	6,698	7,319	6,305	6,530	6,635
Pelican Lake (Heavy Oil)	24,870	23,804	25,671	23,989	26,029
Senlac (Bitumen) [1]	3,057	2,221	5,080	2,574	2,334
	72,350	80,361	77,423	67,822	63,552
Conventional Liquids					
Heavy Oil	17,888	17,127	18,073	18,074	18,290
Light and Medium Oil	30,394	30,644	29,749	30,189	31,004
Natural Gas Liquids [2]	1,206	1,183	1,242	1,184	1,213
Total Crude Oil and Natural Gas Liquids	121,838	129,315	126,487	117,269	114,059
Natural Gas (MMcf/d)					
Oil Sands	53	47	55	57	52
Conventional	784	750	775	799	814
Total Natural Gas	837	797	830	856	866
Total (BOE/d)	261,338	262,148	264,820	259,936	258,392

Notes:
(1) Senlac property sold November 2009.
(2) Natural gas liquids include condensate volumes.

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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 – 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl) [1] [3]					
Price	67.38	75.96	62.68	72.23	59.50
Royalties	10.82	15.81	12.38	2.30	11.92
Transportation and blending	3.04	3.20	2.73	2.82	3.41
Operating	11.34	11.31	11.11	11.57	11.40
Netback	42.18	45.64	36.46	55.54	32.77
Heavy Oil – Christina Lake ($/bbl) [1] [3]					
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
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

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Per-Unit Results – 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
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[2]	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) Operating costs for the year include costs related to long-term incentives of $0.17/BOE.

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

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

Per-Unit Results – 2010[1]					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl)[2] [4]					
Price	58.76	58.76	58.51	54.75	63.33
Royalties	9.08	11.41	9.56	9.38	5.76
Transportation and blending	2.42	2.54	2.40	2.40	2.33
Operating	10.40	9.93	10.32	10.36	11.04
Netback	36.86	34.88	36.23	32.61	44.20
Heavy Oil – Christina Lake ($/bbl)[2] [4]					
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 ($/bbl)[2]					
Price	62.65	61.38	58.93	62.05	68.04
Royalties	12.96	12.76	10.62	14.06	14.34
	1.42	1.04	1.77	1.52	1.30
Transportation and blending					
Operating	12.71	13.44	13.05	13.34	11.13
Netback	35.56	34.14	33.49	33.13	41.27
Heavy Oil - Oil Sands ($/bbl)[2]					
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

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Per-Unit Results – 2010[1]					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil - Conventional ($/bbl)[2]					
Price	63.18	60.45	59.40	61.35	71.16
Royalties	9.01	8.01	7.29	9.65	10.99
Transportation and blending	0.56	0.45	0.60	0.60	0.59
Operating	12.20	13.17	11.41	13.00	11.34
Production and mineral taxes	0.19	0.05	0.17	0.10	0.44
Netback	41.22	38.77	39.93	38.00	47.80
Total Heavy Oil ($/bbl)[2]					
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 ($/bbl)					
Price	61.00	63.60	54.43	58.71	67.42
Royalties	1.12	0.75	1.29	1.16	1.39
Netback	59.88	62.85	53.14	57.55	66.03
Total Liquids ($/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 per-unit results for 2010 have been re-presented on an IFRS basis. Further explanations are provided under Accounting Matters in the Additional Information section.
(2) 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.
(3) Operating costs for the year include costs related to long-term incentives of $0.16/BOE.
(4) Foster Creek and Christina Lake are bitumen properties.

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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

Per-Unit Results – 2009[1]	**(Prepared following previous GAAP)**

	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl)[2] [4]					
Price	55.55	63.60	62.20	54.43	33.44
Royalties	1.42	2.31	1.85	0.66	0.22
Transportation and blending	2.51	1.71	2.50	3.45	2.69
Operating	11.87	10.43	10.85	11.81	15.91
Netback	39.75	49.15	47.00	38.51	14.62
Heavy Oil – Christina Lake ($/bbl)[2] [4]					
Price	53.45	57.07	64.85	57.32	32.44
Royalties	1.24	2.04	1.72	0.83	0.23
Transportation and blending	3.09	0.96	5.36	2.83	3.38
Operating	16.31	18.06	15.31	13.69	18.21
Netback	32.81	36.01	42.46	39.97	10.62
Heavy Oil – Pelican Lake ($/bbl)[2]					
Price	54.77	62.73	61.87	55.39	38.66
Royalties	10.98	12.08	12.27	10.93	8.57
Transportation and blending	0.30	(0.02)	0.67	0.06	0.45
Operating	9.59	11.64	7.03	9.74	10.15
Netback	33.90	39.03	41.90	34.66	19.49
Heavy Oil - Oil Sands ($/bbl)[2]					
Price	55.09	62.75	62.23	55.18	35.47
Royalties	4.98	5.37	5.66	4.86	3.69
Transportation and blending	1.81	1.14	2.15	2.16	1.85
Operating	11.49	11.41	9.69	11.53	13.89
Production and mineral taxes	0.04	0.02	0.07	0.06	-
Netback	36.77	44.81	44.66	36.57	16.04
Heavy Oil - Conventional ($/bbl)[2]					
Price	55.29	62.09	64.62	56.00	37.71
Royalties	5.47	8.61	8.39	4.13	0.61
Transportation and blending	1.91	1.59	1.22	2.75	2.11
Operating	9.47	12.06	9.31	9.72	6.91
Production and mineral taxes	0.14	0.13	(0.04)	0.44	0.02
Netback	38.30	39.70	45.74	38.96	28.06
Total Heavy Oil ($/bbl)[2]					
Price	55.14	62.63	62.72	55.36	35.99
Royalties	5.08	5.95	6.22	4.70	2.98
Transportation and blending	1.83	1.22	1.96	2.28	1.91
Operating	11.07	11.52	9.61	11.13	12.27
Production and mineral taxes	0.06	0.04	0.04	0.14	-
Netback	37.10	43.90	44.89	37.11	18.83
Light and Medium Oil ($/bbl)					
Price	63.34	71.82	68.15	65.28	48.09
Royalties	7.39	11.72	8.09	6.56	3.14
Transportation and blending	0.98	0.70	0.83	1.18	1.21
Operating	9.93	9.53	10.00	9.53	10.67
Production and mineral taxes	2.40	1.70	2.57	1.98	3.37
Netback	42.64	48.17	46.66	46.03	29.70
Total Crude Oil ($/bbl)					
Price	57.22	64.85	64.00	57.95	39.40
Royalties	5.67	7.34	6.66	5.18	3.03
Transportation and blending	1.61	1.10	1.69	2.00	1.71
Operating	10.78	11.04	9.70	10.72	11.82
Production and mineral taxes	0.65	0.44	0.64	0.62	0.95
Netback	38.51	44.93	45.31	39.43	21.89

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Per-Unit Results – 2009[1]	(Prepared following previous GAAP)				
	Year	Q4	Q3	Q2	Q1
Natural Gas Liquids ($/bbl)					
Price	49.08	59.06	49.17	44.65	43.42
Royalties	0.81	0.96	1.00	0.82	0.46
Netback	48.27	58.10	48.17	43.83	42.96
Total Liquids ($/bbl)					
Price	57.14	64.79	63.85	57.81	39.45
Royalties	5.62	7.28	6.60	5.14	3.00
Transportation and blending	1.60	1.09	1.67	1.98	1.69
Operating	10.67	10.94	9.61	10.61	11.69
Production and mineral taxes	0.65	0.44	0.63	0.61	0.94
Netback	38.60	45.04	45.34	39.47	22.13
Total Natural Gas ($/Mcf)					
Price	4.15	4.17	3.14	3.80	5.47
Royalties	0.08	0.16	0.02	0.01	0.15
Transportation and blending	0.15	0.12	0.16	0.16	0.18
Operating	0.86	0.81	0.84	0.83	0.94
Production and mineral taxes	0.05	0.03	0.04	0.07	0.05
Netback	3.01	3.05	2.08	2.73	4.15
Total ($/BOE)					
Price	39.88	44.54	40.43	38.65	35.71
Royalties	2.87	4.05	3.22	2.35	1.81
Transportation and blending	1.24	0.91	1.29	1.41	1.34
Operating[3]	7.71	7.85	7.24	7.52	8.27
Production and mineral taxes	0.46	0.30	0.43	0.52	0.58

Netback	27.60	31.43	28.25	26.85	23.71

Notes:
(1) The per-unit results for 2009 are presented following previous GAAP and have not been re-presented on an IFRS basis. Further explanations are provided under Accounting Matters in the Additional Information section.
(2) 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 - $27.45/bbl; Christina Lake - $28.90/bbl; Pelican Lake - $13.16/bbl; Heavy Oil – Oil Sands - $22.37/bbl; Heavy Oil - Conventional - $9.36/bbl; Total Heavy Oil - $19.68/bbl.
(3) Operating costs for the year include costs related to long-term incentives of $0.09/BOE.
(4) Foster Creek and Christina Lake are bitumen properties.

Impact of Realized Financial Hedging - 2009	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Liquids ($/bbl)	1.10	(0.05)	(0.01)	1.54	3.29
Natural Gas ($/Mcf)	3.63	2.27	4.41	4.33	3.43
Total ($/BOE)	12.16	6.92	13.77	14.91	13.06

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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.

The following table summarizes our net capital investment for 2011 and 2010:

Net Capital Investment ($ millions)	**2011**	**2010**
Capital Investment		
Upstream		
Foster Creek	429	277
Christina Lake	472	346
Total	901	623
Pelican Lake	317	104
Other Oil Sands	197	130
Conventional	788	526
	2,203	1,383
Refining and Marketing	393	656
Corporate	127	76
Capital Investment	2,723	2,115
Acquisitions	71	86
Divestitures	(173)	(307)
Net Acquisition and Divestiture Activity	(102)	(221)
Net Capital Investment	2,621	1,894

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 US$15 to US$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”.

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We also examine the impact of carbon regulation on our major projects, including both our oil sands operations and refining assets. We continue to closely monitor potential GHG legislation developments in the U.S. 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. This regulation currently differentiates oil sands crudes as high carbon intensity crude oils. As an oil sands producer, Cenovus is not directly regulated and will not 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. Cenovus is well positioned within the sector given its typically low steam to oil ratio. This legislation has many complexities that are currently being addressed and in December 2011 the U.S. District Court for the Eastern District of California temporarily suspended the enforcement of the legislation due to several pending federal lawsuits challenging its implementation. We continue to monitor this development.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2011, expenditures beyond normal compliance with environmental regulations were not material. We do not anticipate making material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2012. 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. The revisions made to the policy were approved by both our executive team and our Board. 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 first comprehensive CR report was released in July 2011 and involved a limited assurance engagement with PricewaterhouseCoopers 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.

In 2011, we rolled out the CR Policy across the Company to ensure the commitments articulated are understood and embedded throughout the organization. This rollout included: (i) an interactive e-learning training tool mandatory for employees and contractors to complete; (ii) a Company-wide video emphasizing the six different commitment areas of the revised CR Policy; (iii) a presentation delivered at the Cenovus Innovation Forum; (iv) bi-weekly on-boarding presentations delivered to more than 600 new hires; (v) a news feed called the “R” Factor, highlighting related employee stories; (vi) two lunch and learn events; and (vii) two bulletins on our internal Company webpage.

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In addition, the CR Policy was included as a component in the implementation of the new Cenovus Operating Management System, which was introduced across the Company in 2011. Current steps that we already 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 and 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 and guidelines for behaviours with respect to the acceptance of gifts, conflicts of interest and the appropriate use of Cenovus equipment and technology in a manner that is consistent with leading ethical business practices; and (viii) a requirement for acknowledgement and sign-off on key policies and practices by our Board and employees. Our Board approved the CR Policy on recommendation of the Safety, Environment and Responsibility Committee. The Board is also advised of significant policy contraventions and receives updates on trends, issues or events which could impact Cenovus.

In 2011, Cenovus was included on the Dow Jones Sustainability Index – North America for the second year in a row. Cenovus was also included on the Jantzi Social Index for the first time. The two indexes track the financial performance of the leading companies worldwide with regards to CR performance.

Employees

The following table summarizes our full-time equivalent (“FTE”) employees at December 31, 2011:

	FTE Employees
Oil Sands	1,019
Conventional	580
Refining and Marketing	74
Cenovus-wide	1,137
Total	2,810

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

One hundred percent of our reserves, production and assets are located in North America, which limits our exposure to risks and uncertainties in countries considered politically and economically unstable. Any future operations and related assets 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 further information on foreign exchange rate matters affecting Cenovus.

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DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals presently serve as directors of Cenovus until the end of the next annual meeting of shareholders:

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 June 2007, Mr. Cunningham served as Group Executive Vice President & Chief Operating Officer of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, L.P., and as Interim President & Chief Executive Officer from June 2007 to July 2007. Mr. Cunningham served as a director with the same entity from December 2005 to May 2010. From December 2009 to November 2010 he served as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P. He is currently a director of Agrium Inc. and a director and Chairman of TETRA Technologies, Inc. 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 and President & Chief Executive Officer of Enbridge Inc., a publicly traded energy delivery company. He is a director of Canadian Imperial Bank of Commerce and a member of the North American Review Board of American Air Liquide Holdings, Inc. He is also a member of the National Petroleum Council (an oil and natural gas advisory committee to the U.S. Secretary of Energy), a director of the American Petroleum Institute, Chairman of energy4everyone Foundation and a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.
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. Mr. Delaney was President and Chief Executive Officer of Sherritt International Corporation from 2009 through 2011. He is also Chairman of The Westaim Corporation.

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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. Mr. Ferguson joined a predecessor company in 1984 and became a member of the management team in 1994. 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 currently serving on the board of the Canadian Association of Petroleum Producers. Mr. Ferguson is a Fellow of the Institute of Chartered Accountants of Alberta, a member of the Canadian Institute of Chartered Accountants (CICA), a member of the Canadian Council of Chief Executives and Chair of the Calgary Police Foundation. He previously served as Chairman of CICA's Risk Oversight and Governance Board.
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 and HSBC Bank Canada. He was Chairman and Chief Executive Officer of Fording Canadian Coal 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 is a director of Wajax Corporation. She 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) regarding international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. Ms. Nielsen is also a past director of the Bank of Canada and of the Canada Olympic Committee.
Charles M. Rampacek[5,6,7] Dallas, Texas, United States	2009	Mr. Rampacek is a director of Flowserve Corporation and Pilko & Associates L.P. and a director and Chairman of the Board of Ardent Holdings, LLC. 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.

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 and TVI Pacific Inc. Mr. Thomson is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the World Presidents' Organization.

Notes:
(1) Each of the directors became members of our Board pursuant to the Arrangement.
(2) Former director of Encana.
(3) Member of the Audit Committee.
(4) Member of the Human Resources and Compensation Committee.
(5) Member of the Nominating and Corporate Governance Committee.
(6) Member of the Reserves Committee.
(7) Member of the Safety, Environment and Responsibility Committee.
(8) As an officer and a non-independent director, Mr. Ferguson is not a member of any of the committees of our Board.
(9) Ex-officio, by standing invitation, non-voting member of all other committees of our Board. As an ex-officio non-voting member, Mr. Grandin attends as his schedule permits and may vote when necessary to achieve a quorum.

Executive Officers

The following individuals currently serve as executive officers of Cenovus.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Brian C. Ferguson Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Ferguson's biographical information is included under "Directors".
Ivor M. Ruste Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. Ruste became Executive Vice-President & Chief Financial Officer on November 30, 2009. From May 2006 to November 2009, Mr. Ruste held the following positions with Encana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer effective May 2009; Executive Vice-President & Chief Risk Officer effective January 2008; Vice-President, Finance for the Integrated Oil Division effective January 2007; and Vice-President, Finance of the Corporate Finance Group effective May 2006. From February 2003 to April 2006, he was a partner and the Office Managing Partner for the Edmonton, Alberta office of KPMG LLP, as well as the Alberta Region Managing Partner for KPMG LLP. During this period, he was also a member of the Board of Directors of KPMG Canada and, from December 2003 to March 2006, he was Vice Chair of the Board of Directors for KPMG Canada.
John K. Brannan Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer Mr. Brannan became Executive Vice-President & Chief Operating Officer on December 1, 2010. From November 2009 to November 2010, Mr. Brannan was our Executive Vice-President (President, Integrated Oil Division). Prior to November 2009, Mr. Brannan held the following positions with Encana: Executive Vice-President (President, Integrated Oil Division) effective January 2007; Managing Director, Frontier and International New Ventures effective July 2005; and from November 2003 to June 2005, Managing Director, International & New Ventures.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President, Oil Sands Mr. Chhina became Executive Vice-President, Oil Sands on December 1, 2010. From November 2009 to November 2010, Mr. Chhina was our Executive Vice-President, Enhanced Oil Development & New Resource Plays. Prior to November 2009, Mr. Chhina held the following positions with Encana: Vice-President, Upstream Operations, Integrated Oil Sands Division effective January 2007; and from April 2002 to December 2006, Vice-President, Oil Recovery Business Unit.
Kerry D. Dyte Calgary, Alberta, Canada	Executive Vice-President, General Counsel & Corporate Secretary Mr. Dyte became Executive Vice-President, General Counsel & Corporate Secretary on November 30, 2009. Prior to November 2009, Mr. Dyte held the following positions with Encana: from January 2007 to November 2009, Vice-President, General Counsel & Corporate Secretary; and from December 2002 to December 2006, General Counsel & Corporate Secretary.
Judy A. Fairburn Calgary, Alberta, Canada	Executive Vice-President, Environment & Strategic Planning Ms. Fairburn became Executive Vice-President, Environment & Strategic Planning on November 30, 2009. Prior to 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; Vice-President, Downstream Operations effective January 2007; and Vice-President, Weyburn Business Unit effective July 2004.

Sheila M. McIntosh Calgary, Alberta, Canada	Executive Vice-President, Communications & Stakeholder Relations Ms. McIntosh became Executive Vice-President, Communications & Stakeholder Relations on November 30, 2009. Prior to November 2009, Ms. McIntosh held the following positions with Encana: Executive Vice-President, Corporate Communications effective January 2007; and from April 2002 to December 2006, Vice-President, Investor Relations.
Donald T. Swystun Calgary, Alberta, Canada	Executive Vice-President, Refining, Marketing, Transportation & Development Mr. Swystun became Executive Vice-President, Refining, Marketing, Transportation & Development on December 1, 2010. From November 2009 to November 2010, Mr. Swystun was our Executive Vice-President (President, Canadian Plains Division). Prior to November 2009, Mr. Swystun held the following positions with Encana: Executive Vice-President, (President, Canadian Plains Division) effective January 2007; Executive Vice-President, Corporate Development effective March 2006; and from September 2001 to February 2006, President, Ecuador Region.
Hayward J. Walls Calgary, Alberta, Canada	Executive Vice-President, Organization & Workplace Development Mr. Walls became Executive Vice-President, Organization & Workplace Development on November 30, 2009. Prior to November 2009, Mr. Walls held the following positions with Encana: Executive Vice-President, Corporate Services effective January 2006; and effective November 2003, Vice-President, Information Services & Chief Information Officer.

As of December 31, 2011, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,185,268 Common Shares or approximately 0.16 percent of the number of Common Shares that were outstanding as of such date.

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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 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 President and Chief Executive Officer and a director of Enbridge Inc., a publicly traded energy delivery company, as well as a director of a number of Enbridge subsidiaries. He is a past director and member of the audit committee of Enerflex Systems Income Fund, a compression systems manufacturer. He is also 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 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 currently a director and serves on the audit committee of Wajax Corporation, a publicly traded company engaged in the sale and after-sales parts and service support of mobile equipment, diesel engines and industrial components. She is a past director of the Bank of Canada and of the Canada Olympic Committee.

Colin Taylor (Financial Expert and Audit Committee Chair)

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

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

Pre-Approval Policies and Procedures

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

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

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

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

External Auditor Service Fees

The following table provides information about the fees billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP in the years ended December 31, 2011 and 2010:

($ thousands)	2011	2010
Audit Fees[1]	2,682	1,996
Audit-Related Fees[2]	8	47
Tax Fees[3]	714	157
All Other Fees[4]	66	18
Total	3,470	2,218

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. During 2011, 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. During 2011, the services provided in this category primarily included support of SR&ED claims for Cenovus Energy Inc. and FCCL Partnership.

(4) During 2011, 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.

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, 2011, there were approximately 754 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.

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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 must be reconfirmed by our shareholders at every third annual shareholder meeting, commencing in 2012.

Dividend Reinvestment Plan

In 2010, the Board approved a dividend reinvestment plan, which permits holders of Common Shares to automatically reinvest all or any portion of the cash dividends paid on their Common Shares in additional Common Shares. At the discretion of the Company, the additional Common Shares may be issued from treasury at the average market price or purchased on the market.

Employee Stock Option Plan

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

Ratings

The following information relating to our credit ratings is provided as it relates to our financing costs and liquidity. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on our debt by our rating agencies or a negative change in our ratings outlook could adversely affect our cost of financing and our access to sources of liquidity and capital. See “Risk Factors” in this AIF for further information.

The following table outlines the ratings and outlooks of Cenovus’s debt as of December 31, 2011:

	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	A1(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.

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S&P’s long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB+ by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories. S&P’s Canadian commercial paper ratings scale ranges from A-1(High) to D, which represents the range from highest to lowest quality. A rating

of A-1(Low) is the third highest of eight categories and indicates that the obligor has satisfactory capacity to meet its financial commitments. A ratings outlook gives the potential direction of a short- or long-term rating and the "stable" designation indicates that a rating is not likely to change.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade (i.e., they are subject to moderate credit risk). Such debt securities may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category. Moody's short-term credit ratings are on a scale that ranges from P-1 (highest quality) to NP (lowest quality). A rating of P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations.

DBRS's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A(low) by DBRS is within the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for payment of financial obligations is substantial, but of lesser credit quality than that of higher rated securities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. DBRS's short-term credit ratings are on a scale ranging from R-1(high) to D, which represents the range from highest to lowest quality. A rating of R-1(low) is the third highest of 10 categories and indicates that the short-term debt is of good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial but overall strength is not as favourable as higher rating categories. Cenovus may be vulnerable to future events but qualifying negative factors are considered manageable.

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 $0.22 per share payable on March 30, 2012 to holders of Common Shares of record as of March 15, 2012. In each of the four quarters in 2011, Cenovus paid a dividend of $0.20 per share ($0.80 per share annually).

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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 2011:

2011	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	($ per share)			(thousands)	(US$ per share)			(thousands)
January	34.83	31.15	34.60	32,816	34.78	31.11	34.61	26,480
February	38.36	33.54	37.75	38,526	39.28	33.62	38.91	32,385
March	38.90	33.95	38.30	39,544	40.06	34.25	39.38	34,901
April	38.98	34.50	36.38	33,639	40.73	35.63	38.40	29,366
May	37.34	31.73	35.80	34,622	39.36	32.48	37.09	33,621
June	36.45	32.03	36.40	49,122	37.80	32.62	37.66	35,915
July	38.38	35.25	36.73	30,558	40.61	36.38	38.35	28,291
August	37.01	31.42	35.40	50,680	39.57	31.54	36.08	46,066
September	36.51	29.87	32.27	51,442	37.43	29.02	30.71	32,811
October	37.11	28.85	34.14	44,119	37.35	27.15	34.20	40,191
November	35.53	29.83	34.11	37,497	35.08	28.68	33.39	27,372
December	34.76	30.70	33.83	36,976	34.29	29.64	33.20	27,100

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 three main categories: financial, operational and regulatory. The impact of any risk or a combination of risks in these three 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.

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.

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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 the amount of 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 manufacturing standards; project delays; and supply chain disruptions, including access to skilled labour, leading to scheduling delays or repetition of work. 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 utilize derivative financial instruments and physical delivery contracts, when considered appropriate, to help mitigate the potential impact of changes in interest rates and foreign exchange rates. Management may elect to use derivative instruments to mitigate our net exposure to Canadian dollar operating costs.

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.

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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.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependant 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 and operating 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.

In September 2009, we issued US$3.5 billion in debt securities, all of which were subsequently exchanged for debt securities registered under the Securities Act of 1933, as amended, with the same terms and conditions as the original issued securities. On September 15, 2014, the first tranche of this debt matures in the amount of US$800 million. We have a $3.0 billion committed credit facility, with a maturity of November 30, 2015, of which the entire amount was available at December 31, 2011 to meet operating and capital requirements. Despite the current state of our liquidity, 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 significantly impact our liquidity, may impact our credit ratings and may negatively impact our ability to access existing and/or additional sources of capital. We are also required to comply with financial and operating covenants under our credit facilities and indenture governing our debt securities. We routinely review the covenants and may make changes to our development plans or dividend policy 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.

Interest Rates

We are exposed to fluctuations in interest rates as a result of the use of 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 at prevailing interest rates.

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 material adverse effect 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.

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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.

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: uncertainty of reserves and resources estimates; operational and safety considerations; pipeline transportation and interruptions; phased growth execution; partner risks; competition; technology; third-party claims; land claims; key personnel; and information systems.

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.

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Operational, Health and Safety Considerations

The operation of our properties is subject to hazards of 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 which can interrupt operations, cause loss of or damage to equipment, loss of or injury to life and damage to the environment, property and informational technology systems and related data and control systems.

Our crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; blowouts; equipment failures and other accidents; sour gas releases; uncontrollable flows of crude oil; natural gas or well fluids; adverse weather conditions; pollution; and other environmental risks.

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

Our refining and marketing business is subject to all of the risks inherent in the operation of refineries, terminals, pipelines and other transportation and distribution facilities including, but not limited to: loss of product; slowdowns due to equipment 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.

Pipeline Transportation and 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 excess 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.

Growth Execution

There are certain risks associated with the execution of both our upstream and refining projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; the accuracy of project cost estimates; our ability to finance growth; our ability to source or complete strategic transactions; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving targets and objectives.

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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 ConocoPhillips and operated by ConocoPhillips. The success of our refining operations is dependant on the ability of ConocoPhillips to successfully operate this business and maintain the refining assets. We rely on the judgment and operating expertise of ConocoPhillips in respect of the operation of such refining assets and we also rely on ConocoPhillips to provide us with information on the status of such refining assets and related results of operations.

ConocoPhillips, as an unrelated third party, 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 us and ConocoPhillips, while certain operational decisions may be made by the operator of the applicable assets. While Cenovus and ConocoPhillips 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. For additional information on the proposed split of ConocoPhillips into two separate companies, see “Additional Information”.

Other companies operate a portion of the assets in which we have interests. We have limited ability to exercise influence over operations of these assets or their associated costs. The success and timing of our activities on assets operated by others therefore will depend upon a number of factors that are outside of our control, including the timing and amount of capital expenditures, timing and amount of operating and maintenance expenditures, the operator’s expertise and financial resources, approval of other participants, selection of technology and risk management practices.

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 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.

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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. 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.

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 land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; 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.

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.

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Environmental legislation 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 to 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 legislation 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 regulations or the modification of existing 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. 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 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 federal 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 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.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of such 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.

Alberta's Land-Use Framework

Alberta's Land-Use Framework is to be 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. ALSA contemplates the amendment or extinguishment of 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.

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On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"). 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. An updated draft of the LARP was released on August 29, 2011 after public consultation and stakeholder feedback was obtained. No substantial changes were made to the LARP from these consultations and the LARP is now awaiting provincial cabinet approval prior to being implemented.

If the land use designations for conservation, tourism and recreation areas are approved in their current form, 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 that may adversely affect the market price of our securities and the payment of dividends to our shareholders. The areas identified have no direct impact on our 2011 strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications.

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.

Alberta Environment Water Licences

We currently rely on fresh water, which is obtained under licenses from Alberta Environment to provide 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.

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

Pursuant to the separation and transition agreement ("Separation Agreement") dated November 30, 2009 involving, among others, Encana, 7050372 Canada Inc. and Subco, Encana and Cenovus have each agreed to cooperate fully with each other and our respective counsels in the investigation, prosecution, defense and resolution of certain litigation matters, including, without limitation, certain judicial actions relating to coal bed methane involving Encana (collectively, the "Joint Litigation"). The possible impacts and effects of such agreement are uncertain. Our obligation to cooperate fully with Encana and its counsel in respect of the Joint Litigation and the limitation this may place on the position that Cenovus may otherwise wish to take with respect to these matters may have an adverse effect on Cenovus. The outcome of any of the Joint Litigation matters cannot be predicted and may materially impact our financial condition or results of operations. In addition, the existence of such agreement and our obligations thereunder may have an effect on the manner in which we determine to conduct our business or operations until such time that all of the Joint Litigation is resolved.

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We have certain post-Arrangement indemnification and other obligations under each of the arrangement agreement relating to the Arrangement (the "Arrangement Agreement") and the Separation Agreement. 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.

The Arrangement Agreement contains a number of representations, warranties and covenants, including agreement by each of Cenovus and Encana to indemnify and hold harmless each other against any loss suffered or incurred resulting from a breach of certain tax-related covenants. One of these covenants was that each party would not take any action, omit to take any action or enter into any transaction that could adversely impact the advance income tax rulings and opinions received from the Canada Revenue Agency, and the private letter ruling received from the U.S. Internal Revenue Service, all with respect to income tax consequences of certain aspects of the Arrangement and certain other transactions. With respect to Canadian income taxation, there are a variety of transactions that the parties were or are prohibited from undertaking prior to and after the implementation of the Arrangement. One of these is that no party is permitted to dispose of or exchange property having a fair market value greater than 10 percent of the fair market value of its property, net of liabilities, or undergo an acquisition of control where such disposition or control acquisition is for Canadian tax purposes part of the "series of transactions or events" that includes the Arrangement, except in limited circumstances.

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, 2011, available at www.sedar.com, www.sec.gov and www.cenovus.com.

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.

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MATERIAL CONTRACTS

During the year ended December 31, 2011, 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 15, 2012 in respect of our Consolidated Financial Statements which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of earnings and comprehensive income, shareholders' equity and cash flows for the years ended December 31, 2011 and 2010 and Cenovus's internal control over financial reporting as at December 31, 2011. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Information relating to reserves and resources in this AIF has been calculated by GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd. as independent qualified reserves evaluators. The principals of each of GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd., in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of our securities.

TRANSFER AGENTS AND REGISTRARS

In Canada:

CIBC Mellon Trust Company*
P.O. Box 700 Station B
Montreal, QC H3B 3K3
Canada

In the United States:

Computershare
480 Washington Blvd.
Jersey City, New Jersey 07310
U.S.A.

Tel: 1-866-332-8898 Website: www.canstockta.com/investorServices.do

**On November 1, 2010, CIBC Mellon sold its issuer services business to Canadian Stock Transfer Company Inc. which is currently operating in the name of CIBC Mellon Trust Company during a transition period.*

ADDITIONAL INFORMATION

Additional information relating to Cenovus is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com. Information contained in or otherwise accessible through our website does not form a part of this AIF and is not incorporated by reference into this AIF. Additional financial information is contained in our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2011. 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.

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.

Certain historical information in this AIF has been provided by, or derived from information provided by, certain third parties, including Encana. Although we have no knowledge that would indicate that any such information is untrue or incomplete, we assume no responsibility for the completeness or accuracy of such information or the failure by third parties to disclose events which may have occurred or may affect the completeness or accuracy of such information, but which are unknown to us.

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In July 2011, ConocoPhillips announced its intention to split its Refining and Marketing and its Exploration and Production businesses into two stand-alone companies. If the split is completed, we expect our partnership with ConocoPhillips to be amended to accommodate the separation and holding of the upstream assets and refining assets in two separate companies.

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, 2011 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. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the 2011 and 2010 information has been prepared in accordance with IFRS. The 2009 financial information contained within this AIF has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented in accordance with IFRS. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

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
TM	Trademark of Cenovus Energy Inc.

Natural Gas

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

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.

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APPENDIX A

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

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

1. We have evaluated the Corporation's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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, 2011.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	Cenovus Energy Inc. Evaluation of a Portion of the Canadian Oil & Gas Reserves January 12, 2012	Canada	26,316
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation January 9, 2012	Canada	2,658
			28,974

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. Welsh
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

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

February 13, 2012

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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, 2011, 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/ Judy A. Fairburn
Judy A. Fairburn
Executive Vice-President, Environment and Strategic Planning

/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 14, 2012

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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:

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- 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.

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Chair

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

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

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

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

Secretary

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

Meetings

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

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

Notice of Meeting

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

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

Quorum

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

Attendance at Meetings

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

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

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

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

Minutes

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

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

III. RESPONSIBILITIES

Review Procedures

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

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

Annual Financial Statements

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

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

    (b) Management's Discussion and Analysis.

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

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

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

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

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

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

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

        (i) The accounting policies of the Corporation and any changes thereto.

        (ii) The effect of significant judgments, accruals and estimates.

        (iii) The manner of presentation of significant accounting items.

        (iv) The consistency of disclosure.

    (b) Management's Discussion and Analysis.

    (c) Annual Information Form as to financial information.

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

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

Quarterly Financial Statements

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

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

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

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

Other Financial Filings and Public Documents

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

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Internal Control Environment

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

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

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

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

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

Risk Oversight

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

Other Review Items

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

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

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

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

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

16. Ensure that the Corporation's presentation of reserves has been reviewed with the Reserves Committee of the Board.

17. Review management's processes in place to prevent and detect fraud.

18. Review (a) procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters and (b) a summary of any significant investigations regarding such matters.

19. Meet on a periodic basis separately with management.

External Auditors

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

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

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

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

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

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

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

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

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

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

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

25. Review and evaluate:

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

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

    (c) External audit plans and results.

    (d) Any other related audit engagement matters.

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

26. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 22 through 25, evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present to the Board its conclusions in this respect.

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

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

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

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

(a) Significant findings during the year and management's responses and follow-up thereto.

(b) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.

(c) Any significant disagreements between the external auditors or internal auditors and management.

(d) Any changes required in the planned scope of their audit plan.

(e) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.

(f) The internal audit department mandate.

(g) Internal audit's compliance with the Institute of Internal Auditors' standards.

Internal Audit Group and Independence

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

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

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

Approval of Audit and Non-Audit Services

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

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

36. If the pre-approvals contemplated in paragraphs 34 and 35 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

37. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 34 through 36. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

38. Establish policies and procedures for the pre-approvals described in paragraphs 34 and 35 so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation to management of the Committee's responsibilities under the Exchange Act or applicable CSA and SEC legislation and regulations.

Other Matters

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

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

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

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

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

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

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

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

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

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

Revised Effective: February 14, 2012

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Management's Discussion and Analysis
For the Year Ended December 31, 2011

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated February 15, 2012, should be read with our audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2011 ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory.

Management is responsible for preparing the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviews the MD&A and recommends its approval by the Board.

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated. Effective January 1, 2011, we adopted International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the 2011 and 2010 information has been prepared in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented in accordance with IFRS. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

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INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2011, we had a market capitalization of approximately $26 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. Our total 2011 average crude oil and NGLs production was in excess of 134,000 barrels per day and our average natural gas production was in excess of 650 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties, which we operate and have a 50 percent ownership interest in, are located in the Athabasca Region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca Region is our wholly owned Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta. In addition to our upstream assets, we have 50 percent ownership in two refineries located in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to mitigate the volatility associated with commodity price movements.

Our operational focus is to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Saskatchewan, and to continue the assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural

gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

Our strategy is to focus on the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic test wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects that we expect to develop in this area as well as our current ownership interests are as follows:

	Ownership Interest
Narrows Lake	50 percent[1]
Grand Rapids	100 percent
Telephone Lake	100 percent

[1] Approximate ownership interest

In June 2010, we submitted a joint application and Environmental Impact Assessment ("EIA") for our Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day and be developed in up to three phases. Provided all regulatory requirements are met we anticipate receiving regulatory approval in the middle of 2012 with first production expected in 2016.

At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and EIA for a commercial SAGD operation. The proposed project is expected to have a gross production capacity of 180,000 barrels per day.

Our 100 percent owned Telephone Lake property is located within the Borealis Region and in December 2011, we submitted a revised joint application and EIA. The Telephone Lake project is now expected to have an initial gross production capacity of 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands and tight oil opportunities. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016, we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect 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 balance sheet capacity.

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Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful and growing dividends as part of delivering a strong total shareholder return over the long-term.

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.
- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **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 ConocoPhillips. 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.

OVERVIEW OF 2011

In 2011, we achieved the milestones that we set for the year. We completed our planned capital programs, met or exceeded our production targets, kept our capital and operating costs in line with expectations and ended the year in a stronger financial position than we started. In the third quarter, phase C at Christina Lake achieved first production ahead of schedule and capital expenditures below budget for the entire phase. We have accelerated planned first production from phases D and E at Christina Lake to commence in the fourth quarters of 2012 and 2013, respectively each about six months earlier than originally expected. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design. Construction of the coker and start up activities of the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery were completed with total capital costs of US$3.8 billion (US$1.9 billion net to Cenovus), within 10 percent of its original budget. Demonstrating our strong resource base, our total bitumen, crude oil and NGLs proved reserves increased 22 percent to over 1.7 billion barrels and our best estimate bitumen economic contingent resources increased 34 percent to 8.2 billion barrels. Our operational performance in 2011 and consistent crude oil growth have increased our net asset value and we expect to reach our goal of doubling our December 2009 net asset value by the end of 2015.

OPERATIONAL RESULTS

Our average crude oil and NGLs production increased four percent to 134,239 barrels per day compared to 2010, primarily due to the start of production from phase C at Christina Lake in the third quarter of 2011, improved well performance and plant efficiency at Foster Creek as well as increased production from our Lower Shaunavon tight

oil play. These production increases were partially offset by operational challenges including wet weather and flooding in southern Saskatchewan and Alberta and wild fires in northern Alberta which temporarily curtailed production at Pelican Lake. Our December 2011 average crude oil and NGLs production was 150,977 barrels per day, up 18 percent from the prior year.

At Christina Lake we received regulatory approval from the Alberta Energy Resources Conservation Board ("ERCB") for expansion phases E, F and G. This expansion approval, as well as the positive delineation results, added 270 million barrels of proved bitumen reserves.

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Our best estimate bitumen economic contingent resources increased 2.1 billion barrels or approximately 34 percent from 2010. The substantial increase was primarily due to successful stratigraphic test well drilling, resulting in the conversion of prospective resources to contingent resources.

In the fourth quarter of 2011, we completed coker construction and start up activities of the CORE project at the Wood River Refinery. CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), 10 percent higher than originally budgeted. Structured test runs undertaken to date have been successful, and a five percent increase to clean product yield has been achieved. Testing will continue through the first quarter of 2012, and the Wood River Refinery's total heavy crude oil processing capacity is expected to increase to between 200,000 to 220,000 barrels per day, enhancing our ability to integrate our growing bitumen production.

Other significant 2011 operational results compared to 2010 include:

- Foster Creek production averaging 54,868 barrels per day, an increase of seven percent from 2010;
- Christina Lake production averaging 11,665 barrels per day, an increase of 48 percent from 2010 and ended 2011 producing approximately 23,000 barrels per day;
- Lower Shaunavon average production more than doubling to 2,041 barrels per day;
- Pelican Lake production averaging 20,424 barrels per day, a decrease of 11 percent partly due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Drilling 491 gross stratigraphic test wells, mainly in the first quarter, to support the next phases of expansion at Foster Creek and Christina Lake, gather data on the quality of our emerging projects and support regulatory applications;
- Commencing the regulatory approval process for two of our emerging projects with the filing of a regulatory application for a commercial SAGD operation at our Grand Rapids property with an expected gross production capacity of 180,000 barrels per day and filing a revised regulatory application for Telephone Lake with an expected initial gross production capacity of 90,000 barrels per day. With these applications filed we have 400,000 barrels per day of gross production capacity in the regulatory process;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G;
- Receiving 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;
- Receiving partner approval for expansion phases F, G and H at Foster Creek and expansion phase E at Christina Lake; and
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions. While year over year production was down, production throughout 2011 remained relatively flat with low levels of capital investment.

FINANCIAL RESULTS

Throughout 2011, our financial results benefited from higher crude oil prices and a significant increase in refining crack spreads when compared to 2010. As a result of the increased crack spreads, we saw substantially improved operating cash flow from our Refining and Marketing segment. The higher average crude oil prices improved operating cash flow from our crude oil and NGLs operations, although price had a negative impact on our royalty expense as the Canadian dollar WTI price is used to calculate the royalty rates at our Oil Sands operations.

The financial highlights for 2011 compared to 2010 include:

- Revenues increasing $3,055 million, or 24 percent, primarily due to increased crude oil and NGLs production, improved refined product prices, a 16 percent increase in the average sales price for crude oil and NGLs, excluding financial hedging, higher condensate prices and volumes used for blending partially offset by decreased natural gas volumes and average sales prices;
- Operating cash flow of $981 million from Refining and Marketing, an increase of $905 million, primarily due to higher refining margins that resulted from both higher refined product pricing and discounted crude oil feedstock costs;
- Cash flow of $3,276 million, increasing 36 percent, primarily due to the significant increase in operating cash flow from Refining and Marketing and improved crude oil and NGLs production and average sales price;
- Our Conventional natural gas operations generating $623 million of operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;
- Operating earnings increasing 55 percent or $440 million, primarily due to higher operating cash flow partially offset by increased general and administrative and income tax expenses (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Receiving approval from the 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 resulting in a one-time reduction in royalty expense of approximately $65 million; and
- Paying a quarterly dividend of $0.20 per share.

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STRATEGIC PLAN UPDATE

In 2011, we provided an update to our 10 year strategic plan with a focus on doubling our net asset value between 2010 and 2015. To achieve this goal our 10 year strategic plan now targets:

- Expected gross production capacity at Foster Creek, including phases F, G and H as well as future phases, of between 290,000 to 310,000 barrels per day, an increase of 55,000 to 75,000 barrels per day from the original estimate;
- Accelerating the timelines for production at Foster Creek phases G and H by approximately one year, to 2015 and 2016 respectively, and for production at Christina Lake phases D and E by approximately six months with production now expected at phase D in the fourth quarter of 2012 and at phase E in the fourth quarter of 2013;
- Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016;
- Increasing Conventional crude oil production in Saskatchewan and southern Alberta to approximately 65,000 to 75,000 barrels per day by the end of 2016; and
- Assessing the potential of new oil projects on our existing properties and in new regions with a focus on light oil opportunities.

OUR BUSINESS ENVIRONMENT

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 rate to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates

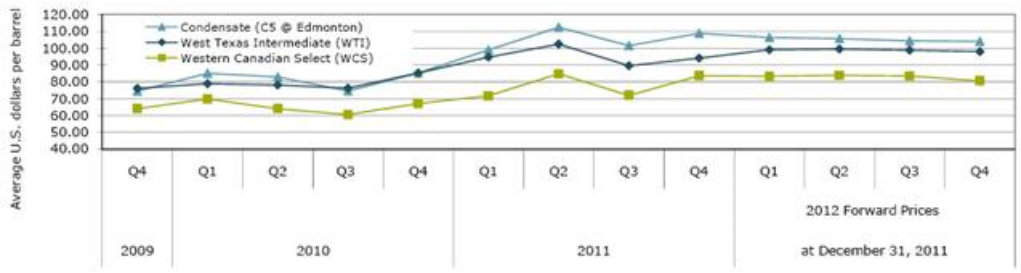
	2011	Q4	Q3	Q2	Q1	2010	Q4	Q3	Q2	Q1	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	95.11	94.06	89.54	102.34	94.60	79.61	85.24	76.21	78.05	78.88	62.09
End of period	98.83	98.83	79.20	95.42	106.72	91.38	91.38	79.97	75.63	83.45	79.36
Western Canadian Select (WCS)											
Average	77.96	83.58	71.92	84.70	71.74	65.38	67.12	60.56	63.96	69.84	52.43
End of period	84.37	84.37	69.38	75.32	91.37	72.87	72.87	64.97	61.38	70.25	71.84
Average Differential WTI-WCS	17.15	10.48	17.62	17.64	22.86	14.23	18.12	15.65	14.09	9.04	9.66
Average Condensate (C5 @ Edmonton)	105.34	108.74	101.48	112.33	98.90	81.91	85.24	74.53	82.87	84.98	61.35
Average Differential WTI-Condensate (premium)/discount	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)	(2.30)	-	1.68	(4.82)	(6.10)	0.74
Refining Margin 3-2-1 Average Crack Spreads ***(US$/bbl)***											
Chicago	24.55	19.23	33.35	29.00	16.62	9.33	9.25	10.34	11.60	6.11	8.54
Midwest Combined (Group 3)	25.26	20.75	34.04	27.19	19.04	9.48	9.12	10.60	11.38	6.82	8.09
Natural Gas Average Prices											
AECO *($/GJ)*	3.48	3.29	3.53	3.54	3.58	3.91	3.39	3.52	3.66	5.08	3.92
NYMEX *(US$/MMBtu)*	4.04	3.55	4.19	4.31	4.11	4.39	3.80	4.38	4.09	5.30	3.99
Basis Differential NYMEX-AECO *(US$/MMBtu)*	0.31	0.17	0.34	0.42	0.29	0.40	0.28	0.78	0.32	0.19	0.40
U.S./Canadian Dollar Exchange Rate											
Average	1.012	0.978	1.020	1.033	1.015	0.971	0.987	0.962	0.973	0.961	0.876

Crude Oil Benchmarks

WTI is an important benchmark for Canadian crude oil since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In 2011, the volatility in the price of WTI was mainly due to the economic conditions of the European Union and the Libyan geopolitical conflict. At their peak in April 2011, WTI prices rose to over US$110.00 per barrel, primarily due to the loss of Libyan supply to the global market. With the resolution of the Libyan conflict, production from the country resumed at the end of the third quarter and is expected to gradually increase in 2012. Concern over the economic health and solvency of several countries within the European Union as well as inland U.S. crude oil market congestion at the end of September dropped WTI to under US$80.00 per barrel, its lowest point in 2011. In the fourth quarter of 2011, WTI improved and ended the year at US$98.83 per barrel on optimism of a strengthening U.S. economy and the announcement of the Seaway Pipeline reversal which more than offset the continued economic concerns in the European Union and OPEC's announcement to increase its 2012 production ceiling. The 2011 average price of WTI also benefited from increased Asian demand, primarily from China.

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WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In 2011, the average WTI-WCS differential was impacted by pipeline restrictions in the first quarter which widened the average differential to over US$22.00 per barrel. These pipeline restrictions were resolved and new delivery capacity to Cushing, Oklahoma was added in the second quarter which helped to narrow the average WTI-WCS differential to under US$18.00 per barrel for the second and third quarters. In the fourth quarter, the WTI-WCS differential further narrowed to under US$11.00 per barrel due to overall stronger refining industry utilizations and increased demand for heavy crude oil partly due to advanced purchases for the CORE project at our Wood River Refinery. When compared to 2010, the average WTI-WCS differential widened as increased production of Canadian heavy crude oil supply and pipeline outages were only partially offset by increased coking capacity and refining industry utilization.



Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. Our blending ratios range from 10 percent to 30 percent. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the 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. Throughout 2011, WTI discounts to offshore light crudes increased and condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland U.S. prices, and do not include an embedded inland U.S. discount included in the WTI benchmark price. However, in the fourth quarter of the 2011, the WTI discount to offshore light crude oils began to decrease with the announcement of the planned flow reversal of crude oil on the Seaway Pipeline in the middle of 2012. This planned flow reversal will supply crude oil to refineries on the U.S. Gulf Coast from the Cushing, Oklahoma hub. With the planned access to Gulf of Mexico markets, WTI prices strengthened in relation to offshore light oil benchmarks.

Refining 3-2-1 Crack Spread Benchmarks

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. Average crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices which increased substantially in 2011. In the fourth quarter of 2011, crack spreads decreased compared to the previous quarter with the announcement that the flow of crude oil on the Seaway Pipeline will be reversed in the middle of 2012, increasing the price of crude oil feedstocks and narrowing the differential to global market prices. The Seaway Pipeline currently moves crude oil from the Gulf of Mexico to Cushing, Oklahoma. When reversed, it will help reduce surplus crude oil supply in the Cushing market by supplying heavy crude oil to the U.S. Gulf Coast refineries.

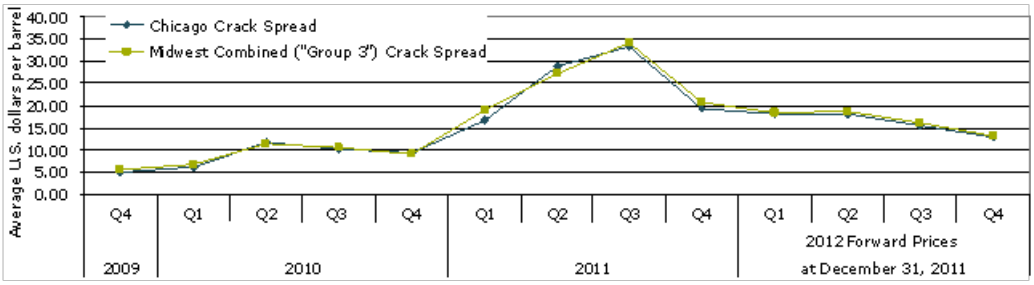


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Benchmark crack spreads are a simplified view of the market based on last-in, first-out accounting, and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many other factors such as the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

Other Benchmarks

Natural gas prices remained low during 2011. The low prices reflect the continued strong growth in supply from liquids-rich natural gas basins and the slow response of demand to lower natural gas prices. We do not expect prices to improve significantly in 2012 as demand growth is not expected to respond quickly enough to absorb the current supply surplus.

During 2011, the Canadian dollar strengthened relative to the U.S. dollar. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative 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 strengthened Canadian dollar reduces our reported results, although a stronger Canadian dollar reduces our current period's refining capital investment.

FINANCIAL INFORMATION

In 2011 we began reporting our financial results in accordance with IFRS. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been re-presented in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the Consolidated Financial Statements.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	2011	2011 vs 2010	2010	2010 vs 2009	2009
					(Prepared following previous GAAP)
Revenues [1]	**15,696**	**24%**	12,641	15%	11,031
Operating Cash Flow [2]	**3,862**	**30%**	2,981	-29%	4,189
Cash Flow [2]	**3,276**	**36%**	2,412	-15%	2,845
- per share – diluted [3]	**4.32**	**35%**	3.20	-16%	3.79
Operating Earnings [2]	**1,239**	**55%**	799	-48%	1,522
- per share – diluted [3]	**1.64**	**55%**	1.06	-48%	2.03
Net Earnings	**1,478**	**37%**	1,081	32%	818
- per share – basic [3]	**1.96**	**36%**	1.44	32%	1.09
- per share – diluted [3]	**1.95**	**36%**	1.43	31%	1.09
Total Assets	**22,194**	**12%**	19,840	-9%	21,755
Total Long-Term Debt	**3,527**	**3%**	3,432	-6%	3,656
Other Long-Term Obligations	**5,873**	**7%**	5,503	-15%	6,507
Capital Investment [4]	**2,723**	**29%**	2,115	-2%	2,162
Cash Dividends [5]	**603**		601		159
- per share [5]	**0.80**		0.80		US$0.20

(1) The 2009 revenue component of realized and unrealized financial hedging net gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.
(2) Financial measure without standardized meaning as prescribed by IFRS ("non-GAAP") and defined within this MD&A.
(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's ("Encana") common share balances based on the Arrangement which is further explained in the Advisory.
(4) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.
(5) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

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REVENUES VARIANCE

	Years Ended December 31,	
($ millions)	**2011 vs 2010**	2010 vs 2009 [1]
Beginning period	$ 12,641	$ 11,031
Increase (decrease) due to:		
Oil Sands	584	428
Conventional	9	(110)
Refining and Marketing	2,397	1,306
Corporate and Eliminations	65	(14)
Ending period	$ **15,696**	$ 12,641

[1] The 2009 revenue component of realized and unrealized financial hedging gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Oil Sands revenues for 2011 increased primarily due to higher average crude oil sales prices, increased crude oil production, as well as higher condensate prices.

Conventional revenues increased slightly in 2011 as higher average crude oil sales prices and light and medium crude oil production were almost completely offset by decreased natural gas average sales prices and expected declines in natural gas production.

Refining and Marketing revenues in 2011 increased primarily due to improved refined product prices and volumes as well as higher revenues related to operational third party sales undertaken by the marketing group.

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

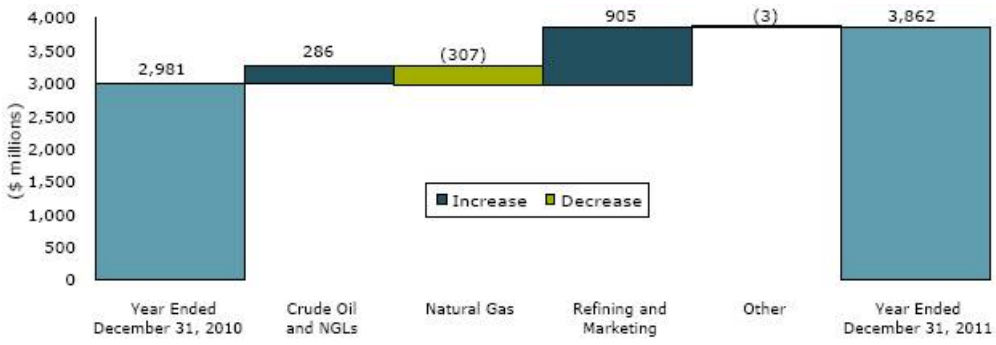
OPERATING CASH FLOW

($ millions)	**2011**	2010	2009
			(Prepared following previous GAAP)
Oil Sands			
Crude Oil and NGLs	$ **1,210**	$ 1,047	$ 1,002
Natural Gas	**52**	77	181
Other	**6**	7	(2)
Conventional			
Crude Oil and NGLs	**881**	758	753
Natural Gas	**725**	1,007	1,880
Other	**7**	9	7
Refining and Marketing	**981**	76	368
Operating Cash Flow	$ **3,862**	$ 2,981	$ 4,189

Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the 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.

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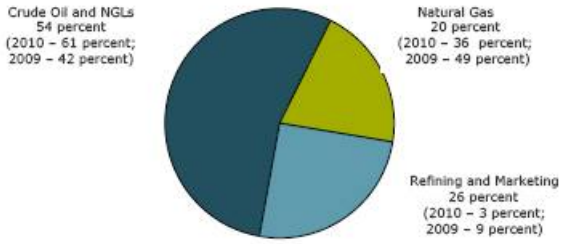
Operating Cash Flow Variance for the Year Ended December 31, 2011 compared to December 31, 2010



Overall, operating cash flow in 2011 increased $881 million primarily due to an increase of $905 million from Refining and Marketing as a result of improved refining margins. Operating cash flow from crude oil and NGLs increased $286 million due to an increase in average sales prices and sales volumes. The $307 million reduction from natural gas was due to decreased volumes, partly due to the divestiture of non-core natural gas properties at the end of the third quarter in 2010 and decreased average sales prices.

Operating Cash Flow of $3,862 million for the Year Ended December 31, 2011

The percentage of our operating cash flow generated from Refining and Marketing increased substantially in 2011 primarily due to improved refining margins. Crude oil and NGLs generated $2,091 million of operating cash flow in 2011 (2010 - $1,805 million; 2009 - $1,755 million), an increase of $286 million, from 2010. Despite this increase, the percentage of operating cash flow from crude oil and NGLs decreased to approximately 54 percent. The natural gas percentage of operating cash flow decreased from 2010 with the expected declines in our production and reduced sales prices.



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

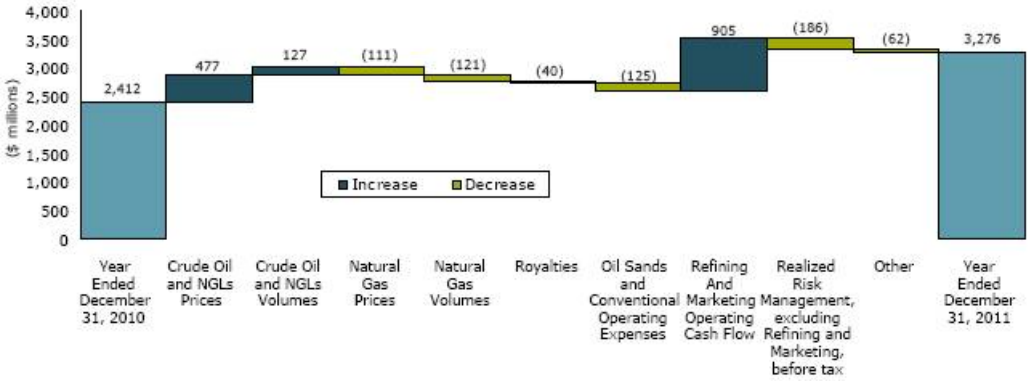
CASH FLOW

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Cash From Operating Activities	$ 3,273	$ 2,591	$ 3,039
(Add back) deduct:			
Net change in other assets and liabilities	(82)	(55)	(26)
Net change in non-cash working capital	79	234	220
Cash Flow	$ 3,276	$ 2,412	$ 2,845

Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash flow is 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.

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Cash Flow Variance for the Year Ended December 31, 2011 compared to December 31, 2010



In 2011 our cash flow increased $864 million primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $905 million, mainly due to improved refining margins;
- A 16 percent increase in the average sales price of crude oil and NGLs to $72.84 per barrel;
- A four percent increase in our crude oil and NGLs sales volumes consistent with increased production primarily from Christina Lake, Foster Creek and conventional light and medium crude oil; and
- Lower interest expense with a stronger average Canadian dollar in 2011 decreasing interest on our U.S. dollar denominated long-term debt and partnership contribution payable as well as decreased interest on our partnership contribution payable as principal repayments are made quarterly.

The increases in our cash flow for 2011 were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $82 million compared to gains of $268 million in 2010;
- Increased operating expenses, primarily from crude oil and NGLs production, with additional personnel at Foster Creek, Christina Lake and Pelican Lake, increased repairs and maintenance and scheduled turnarounds activity, higher electricity costs and increased production from Bakken and Lower Shaunavon areas where production has been predominantly from single well batteries and resulted in increased trucking, fluid hauling and equipment rentals;
- Natural gas production declining 11 percent, as a result of the divestiture of non-core properties in 2010, lower capital investment and expected natural declines;
- An 11 percent decrease in the average natural gas sales price to $3.65 per Mcf;
- A $59 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- Realized foreign exchange losses of $68 million in 2011 compared to losses of $18 million in 2010 primarily on the quarterly settlements of the partnership contribution receivable; and

- An increase in royalties of $40 million primarily as a result of the higher Canadian dollar WTI prices used to calculate royalty rates and improved crude oil production partially offset by decreased natural gas production and receiving approval from the ADOE to include all previous capital investment for Foster Creek expansion phases F, G and H as part our existing Foster Creek royalty calculation resulting in a one-time reduction of approximately $65 million.

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OPERATING EARNINGS

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Net Earnings	$ 1,478	$ 1,081	$ 818
(Add back) deduct:			
Unrealized risk management gains (losses), after-tax [1]	134	34	(494)
Non-operating foreign exchange gains (losses), after-tax [2]	14	153	(210)
Gain (loss) on divestiture of assets, after-tax	91	83	-
Gain on bargain purchase, after-tax	-	12	-
Operating Earnings	$ 1,239	$ 799	$ 1,522

[1] The unrealized risk management gains (losses), after-tax includes 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 is a non-GAAP measure 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. We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods.

The increase in operating earnings in 2011 is consistent with higher operating cash flow partially offset by higher general and administrative costs and income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

NET EARNINGS VARIANCE

($ millions)	
Net Earnings for the Year Ended December 31, 2010	$ 1,081
Increase (decrease) due to:	
Operating Cash Flow	881
Corporate and Eliminations	
Unrealized risk management gains (losses), after-tax	100
Unrealized foreign exchange gains (losses)	(27)
Gain (loss) on divestiture of assets	(9)
Expenses [1]	(86)
Depreciation, depletion and amortization	7
Exploration expense	3
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(472)
Net Earnings for the Year Ended December 31, 2011	**$ 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.

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In 2011, our net earnings increased $397 million compared to 2010. The factors discussed above that increased our operating cash flow in 2011 also increased our net earnings. Other significant factors that impacted our net earnings in 2011 include:

- Unrealized risk management gains, after-tax, of $134 million, compared to gains of $34 million in 2010;
- Unrealized foreign exchange gains of $42 million compared to gains of $69 million in 2010 consistent with the decrease of the Canadian dollar exchange rate at December 31, 2011 on the translation of our U.S. dollar long-term debt partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- An increase of $49 million for general and administrative expenses primarily due to increases in salaries and benefits and office support costs, as well as higher long-term incentive costs;
- Lower gains on the divestiture of assets, as we recognized gains of $107 million in 2011 compared to gains of $116 million in 2010 on the sale of non-core properties;
- A decrease of $7 million in Depletion, Depreciation and Amortization ("DD&A") expense as increased crude oil production and a $45 million impairment of a refining asset were partially offset by the addition of proved reserves at Foster Creek at the end of 2010 and decreased natural gas production; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $683 million, compared to $211 million in 2010.

NET CAPITAL INVESTMENT

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Oil Sands	$ 1,415	$ 857	$ 629
Conventional	788	526	466

Refining and Marketing	**393**	656	1,033
Corporate	**127**	76	34
Capital Investment	**2,723**	2,115	2,162
Acquisitions	**71**	86	3
Divestitures	**(173)**	(307)	(222)
Net Capital Investment [1]	**$ 2,621**	$ 1,894	$ 1,943

[1] Includes expenditures on PP&E and E&E. For purposes of managing our capital program, we do not differentiate between PP&E and E&E expenditures, and therefore we have not split our capital investment within this MD&A.

Oil Sands capital investment in 2011 included site construction, facility engineering and procurement spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment included site preparation and facility construction for expansion phases D, E and F and completion of phase C construction. Pelican Lake capital investment included infill drilling for polymer flooding and facility expansion and maintenance. We also drilled 480 gross stratigraphic test wells in 2011, of which 440 were drilled during the first quarter of 2011 which was our largest program to date. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.

Conventional capital investment in 2011 was primarily focused on the development of our crude oil properties including drilling, completion and facilities work in the Lower Shaunavon and Bakken areas. Our Conventional capital investment increased compared to 2010 and was on plan for 2011 despite flooding in the second quarter of 2011 in southern Saskatchewan which restricted access to our properties.

Refining and Marketing capital investment in 2011 was primarily focused on construction of the CORE project at the Wood River Refinery. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Corporate capital investment in 2011 was for tenant improvements and information technology costs.

Acquisitions and Divestitures

The acquisitions in 2011 were primarily related to purchases of exploration and evaluation lands located contiguous to our existing core areas. Divestitures included the sale of marine terminal facilities in Kitimat, British Columbia and certain undeveloped land.

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CAPITAL INVESTMENT DECISIONS

The table below reflects the outcome of our capital allocation process since the inception of Cenovus. It is important to understand that 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)	**2011**	2010	2009
			(Prepared following previous GAAP)
Cash Flow	**$ 3,276**	$ 2,412	$ 2,845
Capital Investment (Committed and Growth)	**2,723**	2,115	2,162
Free Cash Flow [1]	**553**	297	683
Dividends paid [2]	**603**	601	159
	$ (50)	$ (304)	$ 524

[1] Free cash flow is a non-GAAP measure defined as cash flow less capital investment.
[2] The 2009 dividend represents the fourth quarter dividend determined in connection with the Arrangement based on carve-out earnings and cash flow.

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. This program increases cash flow certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

The realized risk management amounts in the tables below impact our operating cash flow, cash flow, operating earnings and net earnings. Unrealized risk management amounts are a non-cash item included in net earnings and affects the Corporate and Eliminations segment's financial results. Additional information regarding financial instruments can be found in the notes to the Consolidated Financial Statements.

Financial Impact of Risk Management Activities

	2011			2010			2009		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	**$ (135)**	**$ 106**	**$ (29)**	$ (17)	$ (92)	$ (109)	$ 49	$ (102)	$ (53)
Natural Gas	**210**	**38**	**248**	289	152	441	1,105	(566)	539
Refining	**(14)**	**7**	**(7)**	10	(8)	2	(34)	(10)	(44)
Power	**7**	**29**	**36**	(4)	(6)	(10)	(4)	(20)	(24)

Gains (Losses) on Risk Management	68	180	248	278	46	324	1,116	(698)	418
Income Tax Expense(Recovery)	17	46	63	79	12	91	312	(204)	108
Gains (Losses) on Risk Management, after-tax	$ 51	$ 134	$ 185	$ 199	$ 34	$ 233	$ 804	$ (494)	$ 310

In 2011, our risk management strategy resulted in realized losses on our crude oil financial instruments and realized gains on our natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and increased WTI benchmark crude oil prices which ended 2011 at a higher price than in 2010.

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We also recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices at the end of 2011 compared to our contract prices. Details of contract volumes and prices are found in the notes to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL and NGLs PRODUCTION VOLUMES

(barrels per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Oil Sands					
Foster Creek	54,868	7%	51,147	36%	37,725
Christina Lake	11,665	48%	7,898	18%	6,698
Pelican Lake	20,424	-11%	22,966	-8%	24,870
Senlac	-	-	-	-	3,057
Conventional					
Heavy Oil	15,657	-6%	16,659	-7%	17,888
Light & Medium Oil	30,524	4%	29,346	-3%	30,394
NGLs [1]	1,101	-6%	1,171	-3%	1,206
	134,239	4%	129,187	6%	121,838

[1] NGLs include condensate volumes.

In 2011, our crude oil and NGLs production increased four percent primarily due to higher production at Christina Lake, Foster Creek and Conventional light and medium crude oil. These increases were partially offset by the temporary curtailment of production at Pelican Lake from wild fires which restricted pipeline transportation in the second quarter and the scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake. Conventional production was impacted by natural declines at our heavy oil operations, flooding and wet weather in southern Saskatchewan and Alberta in the second quarter, poor winter weather in the first quarter and the divestiture of non-core assets in the second quarter of 2010. Our average crude oil and NGLs production for December 2011 was 150,977 barrels per day, an increase of 22,971 barrels per day or 18 percent from December 2010 and was primarily due to increased production from Christina Lake and Conventional light and medium oil. Further information on the changes in our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Conventional	619	-11%	694	-11%	784
Oil Sands	37	-14%	43	-19%	53
	656	-11%	737	-12%	837

The decrease in our 2011 natural gas production compared to 2010 was due to our strategic decision to restrict capital spending on our natural gas assets over the prior two years in favour of increasing investment in crude oil projects. In 2010, we also divested of non-core natural gas properties which had produced approximately four percent of our 2010 production. Weather related issues, including extreme cold in the first quarter and wet weather in the second quarter of 2011, also reduced our natural gas production. While year over year natural gas production decreased, 2011 natural gas production remained consistent during the year despite low levels of capital investment. Further information on the changes in our natural gas production can be found in the Reportable Segments section of this MD&A.

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OPERATING NETBACKS

	2011		2010		2009	
	Crude Oil & NGLs ($/bbl)	Natural Gas ($/Mcf)	Crude Oil & NGLs ($/bbl)	Natural Gas ($/Mcf)	Crude Oil & NGLs ($/bbl)	Natural Gas ($/Mcf)
					(Prepared following previous GAAP)	
Price [1]	$ 72.84	$ 3.65	$ 62.96	$ 4.09	$ 57.14	$ 4.15
Royalties	9.84	0.06	9.33	0.07	5.62	0.08
Transportation and blending [1]	2.76	0.15	1.88	0.17	1.60	0.15
Operating expenses	13.47	1.10	11.74	0.95	10.67	0.86

Production and mineral taxes	**0.56**	**0.04**	0.62	0.02	0.65	0.05
Netback excluding Realized Risk Management	**46.21**	**2.30**	39.39	2.88	38.60	3.01
Realized Risk Management Gains (Losses)	**(2.79)**	**0.87**	(0.36)	1.07	1.10	3.63
Netback including Realized Risk Management	**$ 43.42**	**$ 3.17**	$ 39.03	$ 3.95	$ 39.70	$ 6.64

(1) The crude oil and NGLs price and transportation and blending costs exclude $24.91 per barrel (2010 - $20.36 per barrel; 2009 - $14.55 per barrel) of condensate purchases which is blended with heavy crude oil.

In 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $6.82 per barrel primarily due to increased sales prices consistent with higher benchmark prices. Increased benchmark pricing also increased royalties. The increased sales prices were partially offset by higher operating expenses and transportation and blending costs. The increase in operating expenses was primarily due to higher staffing levels and increased repairs and maintenance activity at Foster Creek, Christina Lake and Pelican Lake. Transportation costs increased as a result of pursuing new markets for our increasing crude oil production.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $0.58 per Mcf primarily due to lower sales prices and increased operating expenses.

Further discussion on the items included in our operating netbacks is included 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.

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REPORTABLE SEGMENTS

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include 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 2011 include:

- A 270 million barrel increase in proved reserve volumes primarily due to receiving regulatory approval for Christina Lake phases E, F and G;
- Foster Creek adding 56 million barrels of proved reserves with the positive results from delineation drilling, improved recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Achieving first production at Christina Lake phase C in August ahead of schedule. Capital expenditures for the entire phase were below budget. Net production at Christina Lake was approximately 23,000 barrels per day at the end of the year;
- Implementing steam dilation as part of Christina Lake phase C start up which accelerated the initial start-up of production from well pairs;
- Foster Creek average production increasing seven percent to 54,868 barrels per day and Christina Lake production increasing 48 percent to an average of 11,665 barrels per day;
- Completing scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake on time and on budget;
- Receiving ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation resulting in a one-time reduction of about $65 million in our royalty expense;
- Receiving approval from the ERCB for Christina Lake expansion phases E, F and G;
- Receiving partner approval for Foster Creek expansion phases F, G and H and Christina Lake phase E;
- Successfully completing a large winter stratigraphic test well program with 480 gross wells drilled mainly in the first quarter to further progress our Oil Sands projects and address potential Pelican Lake lease expiries;
- Our best estimate bitumen contingent resources increasing by 2.1 billion barrels or approximately 34 percent primarily on transfers from prospective resources based on the results of our 2011 stratigraphic test well program;
- Pelican Lake production decreasing 11 percent to an average of 20,424 barrels per day, primarily due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G; and
- Updating our strategic plan which targets:
  - Increasing our expected total gross production capacity from Foster Creek phases F, G and H and future phases by 55,000 to 75,000, barrels per day from the original estimate;
  - Accelerating the timelines for first production at Foster Creek phases G and H by approximately one year;
  - Expected first production at Christina Lake phase D and phase E in the fourth quarters of 2012 and 2013 respectively, approximately six months earlier than initially planned. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design; and
  - Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016.

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OIL SANDS - CRUDE OIL

Financial Results

($ millions)	**2011**	2010	2009[1]
			(Prepared following previous GAAP)
Gross Sales	**$ 3,217**	$ 2,610	$ 2,008
Less: Royalties	**282**	276	129

Revenues	**2,935**	2,334	1,879
Expenses			
Transportation and blending	**1,229**	934	626
Operating	**409**	339	297
Production and mineral tax	**-**	-	1
(Gains) losses on risk management	**87**	14	(47)
Operating Cash Flow	**1,210**	1,047	1,002
Capital Investment	**1,401**	850	629
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (191)**	$ 197	$ 373

(1) In 2009, realized financial hedging gains in revenue of $48 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Revenues Variances

($ millions)	Year Ended December 31, 2010	Price	Volume	Royalties	Condensate(1)	Year Ended December 31, 2011
	$ 2,334	253	97	(6)	257	**$ 2,935**

(1) Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

Production Volumes

Crude oil (barrels per day)	**2011**	**2011 vs 2010**	2010	2010 vs 2009	2009
Foster Creek	**54,868**	**7%**	51,147	36%	37,725
Christina Lake	**11,665**	**48%**	7,898	18%	6,698
Subtotal	**66,533**	**13%**	59,045	33%	44,423
Pelican Lake	**20,424**	**-11%**	22,966	-8%	24,870
Senlac	**-**	**-**	-	-	3,057
	86,957	**6%**	82,011	13%	72,350

Foster Creek and Christina Lake Production Volumes by Quarter

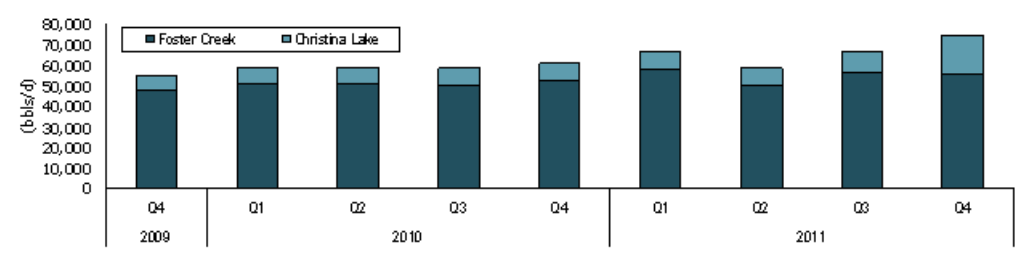


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In 2011, our average crude oil sales price increased 14 percent to $67.99 per barrel compared to 2010, consistent with the increase in the WCS benchmark price partially offset by higher condensate costs and the strengthening of the Canadian dollar.

Foster Creek production increased seven percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio, partially offset by the scheduled turnaround completed in the second quarter of 2011. The 48 percent increase in production at Christina Lake was the result of the start up of phase C in the third quarter of 2011, two well pairs which came on production in the fourth quarter of 2010 and four wells (which use our Wedge Well™ technology) which came on production in 2011, partially offset by a scheduled turnaround completed in the second quarter of 2011. The decline in our Pelican Lake production was primarily due to the temporary curtailment of production in the second quarter of 2011 due to wild fires in the area which decreased production by approximately 500 barrels per day for the year and a scheduled turnaround in the third quarter of 2011 which reduced production by approximately 300 barrels per day for the year. Production at Pelican Lake was also reduced by expected natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and price, volume, allowed operating and capital costs for post-payout projects (Foster Creek and Pelican Lake). Royalties increased $6 million in 2011 primarily due to increased production at Christina Lake and Foster Creek, higher Canadian dollar WTI prices and Foster Creek being in post–payout for a full year after achieving payout in the first quarter of 2010. Royalties would have been about $65 million higher had we not received ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation. Also partially offsetting these increases were higher capital investment and decreased production at Pelican Lake. The effective royalty rates for 2011 were 16.8 percent at Foster Creek (2010 – 16.2 percent; 2009 – 2.7 percent), 5.2 percent at Christina Lake (2010 – 3.9 percent; 2009 – 2.3 percent) and 11.5 percent at Pelican Lake (2010 – 21.1 percent; 2009 – 20.1 percent).

Transportation and blending costs increased $295 million in 2011. The condensate (blending) portion of the increase was $257 million and was the result of increases in the average cost of condensate and volumes required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $38 million primarily as a result of higher production volumes, increased transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions and additional transportation allowing us to access an offshore market in the fourth quarter.

Our 2011 operating costs were primarily for staffing, workovers, repairs and maintenance; Foster Creek and Christina Lake fuel costs; and chemical usage at Pelican Lake

and Foster Creek. In total, operating costs increased $70 million in 2011 due to scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake, higher staffing levels, increased repairs and maintenance expense and higher long-term incentive expense, partially offset by decreased trucking and chemical costs.

Risk management activities resulted in realized losses of $87 million (2010 – losses of $14 million; 2009 – gains of $47 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of expected natural declines, our natural gas production decreased to 37 MMcf per day in 2011 (2010 – 43 MMcf per day; 2009 – 53 MMcf per day). As a result of the decreased production and lower natural gas prices, operating cash flow declined to $52 million for 2011 (2010 - $77 million; 2009 - $181 million).

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OIL SANDS - CAPITAL INVESTMENT

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Foster Creek	$ 429	$ 277	$ 262
Christina Lake	472	346	224
Subtotal	901	623	486
Pelican Lake	317	104	72
New Resource Plays	180	113	17
Other [1]	17	17	54
Capital Investment [2]	$ 1,415	$ 857	$ 629

[1] Includes Athabasca natural gas.
[2] Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2011 was 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 and the drilling of stratigraphic test wells to support the development of our Oil Sands projects.

As compared to 2010, Foster Creek capital investment for 2011 increased primarily as a result of drilling 118 gross stratigraphic test wells in 2011 (2010 – 82 wells; 2009 – 65 wells) and higher spending on site construction, facility engineering and procurement for expansion phases F, G and H. Foster Creek capital investment also included maintenance capital on our producing phases and infrastructure spending.

Christina Lake capital investment was higher in 2011 compared to 2010 due primarily to the phase D, E and F expansions, including site preparation and facility construction, maintenance capital on producing phases and drilling 63 gross stratigraphic test wells (2010 – 24 wells; 2009 – 28 wells). We expect to increase gross production capacity to approximately 138,000 barrels per day with the completion of phases D and E. First production at phase D is expected in the fourth quarter of 2012 and first production at phase E is expected in the fourth quarter of 2013, both phases are now expected to commence production approximately six months earlier than initially scheduled. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design.

Pelican Lake capital investment for 2011 was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance capital. Facilities spending was focused on expanding fluid capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

(gross production wells drilled [1])	2011	2010	2009
Foster Creek	21	37	42
Christina Lake	19	32	-
Subtotal	40	69	42
Pelican Lake	31	12	5
Grand Rapids	-	1	-
Other	3	-	11
	74	82	58

[1] Includes wells drilled using our Wedge Well™ technology

Capital investment in new resource plays in 2011 was mainly related to the drilling of stratigraphic test wells, completion of seismic programs to support future oil sands projects and the Grand Rapids pilot project. First oil from the Grand Rapids pilot project was achieved in the third quarter of 2011. Results to date are as expected and will give us a better understanding of the performance of SAGD in the Grand Rapids formation.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the first quarter of 2011 and began our next stratigraphic test well drilling program in the fourth quarter. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, 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.

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We also drilled a number of wells at Pelican Lake to address potential lease expiries. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter.

Our 2011 stratigraphic test well program provided the primary basis for the 2.1 billion barrel increase to our best estimate bitumen contingent resources as results from the program caused prospective resources to be reclassified as contingent resources.

(gross stratigraphic test wells drilled)	2011	2010	2009
Foster Creek	118	82	65
Christina Lake	63	24	28
Subtotal	181	106	93
Pelican Lake	57	-	-
Narrows Lake	47	39	-
Grand Rapids	59	71	17
Telephone Lake	40	26	-
Borealis	44	-	-
Other	52	17	-
	480	259	110

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of 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 assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2011 include:

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $623 million;
- Average crude oil production from our Lower Shaunavon area more than doubling to 2,041 barrels per day with capital spending focusing on drilling, completions and facilities;
- Flooding which resulted in restricted access and shut-in production at our Bakken, Lower Shaunavon and Weyburn operations in the second quarter which reduced our production by approximately 1,400 barrels per day;
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions;
- Shifting our capital investment focus from natural gas to crude oil where we increased crude oil capital investment by 89 percent and drilled an additional 145 crude oil wells compared to 2010; and
- Updating our strategic plan which targets production of 65,000 to 75,000 barrels per day from our conventional crude oil operations in Saskatchewan and southern Alberta by the end of 2016 as well as assessing the potential of new crude oil projects on our existing properties and in new regions with a focus on tight oil opportunities.

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CONVENTIONAL - CRUDE OIL and NGLs

Financial Results

($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
Gross Sales	$ 1,492	$ 1,229	$ 1,161
Less: Royalties	193	153	119
Revenues	1,299	1,076	1,042
Expenses			
Transportation and blending	104	86	87
Operating	244	199	172
Production and mineral taxes	27	28	28
(Gains) losses on risk management	43	5	2
Operating Cash Flow	881	758	753
Capital Investment	686	363	223
Operating Cash Flow in Excess of Related Capital Investment	$ 195	$ 395	$ 530

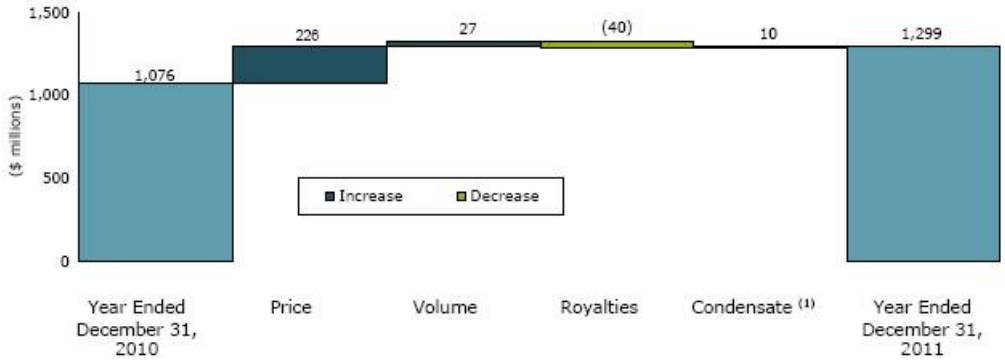
[1] In 2009, realized financial hedging losses in operating costs of $2 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Production Volumes

(barrels per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Heavy Oil					
Alberta	15,657	-6%	16,659	-7%	17,888
Light and Medium Oil					
Alberta	10,763	-1%	10,854	-9%	11,959
Saskatchewan	19,761	7%	18,492	-%	18,435

NGLs	**1,101**	**-6%**	1,171	-3%	1,206
	47,282	**-%**	47,176	-5%	49,488

Revenues Variance for the Years Ended December 31, 2011 compared to December 31, 2010



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

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Our average crude oil and NGLs sales price increased 19 percent to $81.41 per barrel, consistent with the increase in crude oil benchmark prices.

Our sales and production volumes increased slightly, primarily because of higher light and medium crude oil production from our Bakken and Lower Shaunavon areas. These increases were mostly offset by the effects of cold weather in Alberta in early 2011, wet weather in Alberta and Saskatchewan in the middle of 2011, natural declines and the 2010 divestiture of non-core properties.

Royalties increased by $40 million primarily as a result of increased crude oil prices which resulted in an effective crude oil royalty rate of 14.2 percent (2010 – 13.3 percent; 2009 – 11.4 percent).

Transportation and blending costs increased $18 million. The condensate portion of the increase was $10 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending consistent with the decline in heavy oil production. Transportation costs increased $8 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls.

Our primary operating costs components were electricity, repairs and maintenance, workover activity and staff costs. Operating costs increased $45 million for 2011 primarily due to higher electricity costs, increased repairs and maintenance and workover activity, higher salaries and benefits, increased trucking and waste handling costs as well as increased equipment rentals.

Risk Management activities resulted in realized losses of $43 million (2010 - losses of $5 million; 2009 – losses of $2 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased $200 million in 2011 primarily due to a $323 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, partially offset by higher crude oil and NGLs prices and increased light and medium crude oil production.

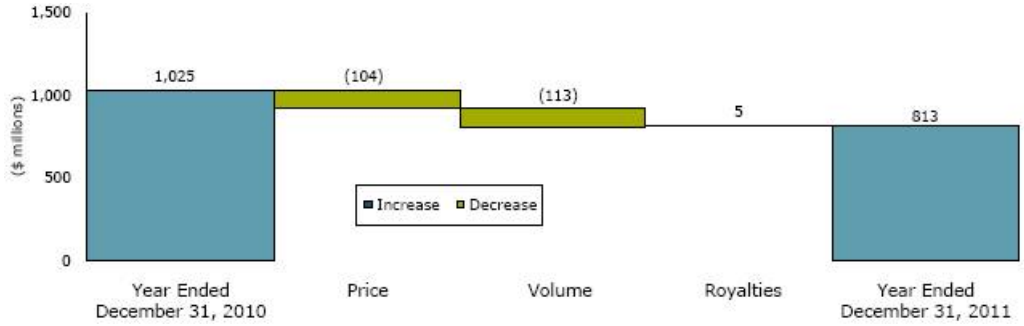
CONVENTIONAL - NATURAL GAS

Financial Results

($ millions)	2011	2010	2009 (1)
			(Prepared following previous GAAP)
Gross Sales	**$ 825**	$ 1,042	$ 1,189
Less: Royalties	**12**	17	19
Revenues	**813**	1,025	1,170
Expenses			
Transportation and blending	**34**	44	45
Operating	**240**	231	236
Production and mineral taxes	**9**	6	15
(Gains) losses on risk management	**(195)**	(263)	(1,006)
Operating Cash Flow	**725**	1,007	1,880
Capital Investment	**102**	163	243
Operating Cash Flow in Excess of Related Capital Investment	**$ 623**	$ 844	$ 1,637

(1) In 2009, realized financial hedging gains in revenue of $1,007 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Revenues Variance for the Years Ended December 31, 2011 compared to December 31, 2010



Our natural gas revenues and operating cash flow were lower in 2011 primarily due to lower production and average sales prices. The decline in our average sales price is consistent with the change in the benchmark AECO price. The cumulative impact of restricted natural gas capital spending over the last two years, the 2010 divestiture of non-core properties which had produced approximately four percent of our 2010 production, extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes to 619 MMcf per day for 2011 (2010 – 694 MMcf per day; 2009 – 784 MMcf per day). While year over year production was down, production within 2011 remained relatively flat with low levels of capital investment.

Royalties decreased $5 million in 2011 due to lower production and prices. The average 2011 royalty rate was 1.5 percent (2010 – 1.7 percent; 2009 – 1.6 percent).

Transportation costs decreased $10 million due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, staffing costs and electricity. Operating expenses increased $9 million in 2011 as higher expenses associated with electricity, increased workover activity and long-term incentives were partially offset by reduced operations due to divestitures in 2010 and lower production volumes.

Risk management activities resulted in realized gains in 2011 of $195 million (2010 – gains of $263 million; 2009 – gains of $1,006 million) consistent with our 2011 contract price exceeding the 2011 average benchmark price.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $221 million primarily due to lower production volumes and average sales prices decreasing operating cash flow partially offset by a $61 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Crude Oil	$ 686	$ 363	$ 223
Natural Gas	102	163	243
Capital Investment[1]	$ 788	$ 526	$ 466

[1] Includes expenditures on PP&E and E&E assets.

Capital investment in our Conventional segment was focused on our crude oil development opportunities and high value natural gas opportunities such as CBM recompletions. Increased crude oil capital investment in Saskatchewan was focused on drilling and facility work at Weyburn and appraisal projects, drilling, completions and facilities work in the Lower Shaunavon and Bakken areas. Alberta crude oil capital investment was focused on drilling activities. Despite the impact of flooding in southern Saskatchewan in the second quarter we were able to complete our 2011 planned capital investment.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to Alberta coal bed methane development.

(net wells)	2011	2010	2009
Crude Oil	325	180	105
Natural Gas	65	495	502
Recompletions	1,122	1,194	855
Stratigraphic Test Wells	11	9	5

REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include 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.

Significant factors related to our Refining and Marketing segment in 2011 include:

- Increased operating cash flow of $905 million primarily due to improved refining margins, consistent with higher benchmark crack spreads, and higher refinery utilization;

- Completed coker construction and start up activities of the CORE project in the fourth quarter of 2011; and
- Our refineries operating at 89 percent of capacity producing 419 thousand barrels per day of refined products.

Financial Results

($ millions)	2011	2010	2009[1]
			(Prepared following previous GAAP)
Revenues	$ 10,625	$ 8,228	$ 6,922
Purchased product	9,149	7,674	5,986
Gross margin	1,476	554	936
Expenses			
Operating expenses	481	488	534
(Gain) loss on risk management	14	(10)	34
Operating Cash Flow	981	76	368
Capital Investment	393	656	1,033
Operating Cash Flow in Excess (Deficient) of Capital Investment	$ 588	$ (580)	$ (665)

[1] In 2009, realized financial hedging losses in purchased product of $34 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The gross margin for Refining and Marketing increased $922 million for 2011 primarily due to the significant improvement in refined product prices which more than offset higher purchased product costs compared to 2010. Refined product prices continue to be tied to global market prices which increased substantially in 2011. Purchased product costs, which are accounted for on a first-in, first-out basis, reflected the benefit of discounted heavy crude oil as well as discounts to U.S. inland crude oil for much of 2011. Both the heavy and inland crude oil discounts that benefited our refining financial results throughout 2011, reduced substantially midway through the fourth quarter with the announced plan to increase the transportation of crude oil to the U.S. gulf coast reducing the surplus that had generated the discounts. The benefit to our refining results of discounted purchased product prices demonstrates the effectiveness of our objective to economically integrate our heavy oil production. Gross margins realized in 2011 also reflected the impact of higher utilization when compared to 2010.

Operating costs, consisting mainly of labour, maintenance, utilities and supplies, decreased by $7 million in 2011 primarily due to the impact of a stronger Canadian dollar and reduced scheduled turnarounds costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $905 million in 2011 primarily due to the higher refining gross margins. This contrasts with 2010 which was affected by weaker refined product prices, refinery optimization and scheduled turnarounds. Capital investment decreased by $263 million in 2011 as CORE project construction neared completion.

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REFINERY OPERATIONS [1]

	2011	2010	2009
Crude oil capacity *(Mbbls/d)*	452	452	452
Crude oil runs *(Mbbls/d)*	401	386	394
Crude utilization *(percent)*	89	86	87
Refined products *(Mbbls/d)*	419	405	417

[1] Represents 100 percent of the Wood River and Borger refinery operations.

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 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. Refining capacity increases attributable to the CORE project at the Wood River Refinery, including expanded coking and heavy oil processing capacities will be reflected in 2012 operations as plant test runs proceed.

Crude utilization in 2011 improved as the 2010 utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and scheduled turnarounds.

REFINING AND MARKETING - CAPITAL INVESTMENT

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Wood River Refinery	$ 346	$ 568	$ 944
Borger Refinery	45	87	88
Marketing	2	1	1
Capital Investment	$ 393	$ 656	$ 1,033

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River Refinery. In 2011, of the $346 million capital expenditures at the Wood River Refinery, $243 million were related to the CORE project. In the fourth quarter of 2011 we completed the CORE project coker construction. Total CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), or about 10 percent higher than originally budgeted.

The balance of the 2011 capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
Revenues	**$ (59)**	$ (124)	$ (110)
Expenses ((add)/deduct)			
Purchased product	**(59)**	(123)	(110)
Operating	**(1)**	(3)	-
(Gains) losses on risk management	**(180)**	(46)	698
	$ 181	$ 48	$ 698

[1] The 2009 revenue and operating cost components of unrealized financial hedging losses, $668 million and $30 million respectively, have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The Corporate and Eliminations segment includes intersegment eliminations that relate 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 long-term power purchase contracts.

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The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
General and administrative	**$ 295**	$ 246	$ 211
Finance costs	**447**	498	476
Interest income	**(124)**	(144)	(187)
Foreign exchange (gain) loss, net	**26**	(51)	304
(Gain) loss on divestiture of assets	**(107)**	(116)	(2)
Other (income) loss, net	**4**	(13)	-
	$ 541	$ 420	$ 802

[1] 2009 interest, net has been reclassified to interest income and finance costs and accretion of asset retirement obligations has been reclassified to finance costs to conform to the current year's IFRS presentation.

General and administrative expenses increased $49 million in 2011. Increased staffing levels in 2011 to support our growth resulted in higher salaries and benefits, higher long-term incentive expense and increased office support costs.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In 2011, our finance costs were $51 million lower than 2010 primarily as a result of a stronger average Canadian dollar in 2011 reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as principal payments are made quarterly. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for 2011 was 5.5 percent (2010 – 5.8 percent; 2009 – 5.5 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for 2011 decreased by $20 million from 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as the balance is being collected combined with a stronger average Canadian dollar.

In 2011, we reported net foreign exchange losses of $26 million (2010 - gains of $51 million; 2009 – losses of $304 million), which includes unrealized gains of $42 million (2010 – unrealized gains of $69 million; 2009 – unrealized losses of $327 million) and realized losses of $68 million (2010 – realized losses of $18 million; 2009 – realized gains of $23 million). The decrease of the Canadian dollar exchange rate at December 31, 2011 from 2010 led to unrealized losses on our U.S. dollar denominated long-term debt partially offset by net gains on our U.S. dollar denominated partnership contribution receivable.

A net gain of $107 million was recorded on the divestiture of assets in 2011 (2010 – $116 million; 2009 - $2 million) mainly due to the sale of marine terminal facilities as well as certain non-core assets.

DEPRECIATION, DEPLETION and AMORTIZATION

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Oil Sands	**$ 347**	$ 375	
Conventional	**778**	799	
Upstream	**1,125**	1,174	$ 1,250
Refining and Marketing [1]	**130**	96	232
Corporate and Eliminations	**40**	32	45
	$ 1,295	$ 1,302	$ 1,527

[1] On the January 1, 2010 transition to IFRS we elected to measure the carrying value of our refineries at their then estimated fair value resulting in a permanent $2.6 billion reduction to their carrying value and decreasing DD&A expense in 2010 compared to 2009.

For 2011, Oil Sands DD&A decreased $28 million as higher sales volumes at Foster Creek and Christina Lake were offset by lower sales volumes at Pelican Lake and lower Oil Sands DD&A rates. The lower Oil Sands DD&A rates for 2011 were mostly due to the significant addition of proved reserves at Foster Creek at the end of 2010.

DD&A in the Conventional segment decreased $21 million in 2011 primarily due to the decrease in natural gas production volumes and the disposition of non-core assets.

Refining and Marketing DD&A increased $34 million of which $45 million was due to the impairment of a catalytic cracking unit at the Wood River Refinery which will not be used in future operations. Refining and Marketing DD&A in 2010 included a loss on impairment of a redundant processing unit at the Borger Refinery of $14 million. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX EXPENSE

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Current tax	$ 154	$ 82	$ 934
Deferred tax	575	141	(590)
	$ 729	$ 223	$ 344

When comparing 2011 to 2010, our current tax expense increased primarily due to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception.

When comparing 2011 to 2010, our deferred tax expense increased primarily due to increased income from our Refining and Marketing segment which attract income tax at the higher U.S. tax rates and higher unrealized risk management gains.

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

($ millions, except percent amounts)	2011	2010	2009 (Prepared following previous GAAP)
Earnings before income tax	$ 2,207	$ 1,304	$ 1,162
Canadian statutory rate	26.7%	28.2%	29.2%
Expected income tax	589	368	339
Effect of taxes resulting from:			
Foreign tax rate differential	78	(22)	3
Non-deductible stock-based compensation	18	34	-
Multi-jurisdictional financing	(50)	(93)	(134)
Foreign exchange gains (losses) not included in net earnings	(9)	28	58
Non-taxable capital (gains) losses	(9)	(13)	30
Capital loss	26	(107)	-
Adjustments arising from prior year tax filings	31	26	(16)
Other	55	2	64
	729	223	344
Effective tax rate	33.0%	17.1%	29.6%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

The increase in our effective tax rate in 2011 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 and lower benefits of multi-jurisdictional financing. The effective tax rate for 2010 was unusually low because of a tax benefit recorded in respect of losses incurred in the U.S. in 2010.

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 into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:

· 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.

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 INFORMATION

($ millions, except per share amounts)	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009 (Prepared following previous GAAP)
Production Volumes									
Crude Oil and NGLs	144,273	133,496	121,762	137,355	129,593	128,067	128,566	130,549	129,315
Natural Gas	660	656	654	652	688	738	751	775	797
Revenues [1]	4,329	3,858	4,009	3,500	3,363	2,962	3,094	3,222	2,970
Operating Cash Flow [2]	1,019	945	1,064	834	815	661	665	840	954
Cash Flow [2]	851	793	939	693	645	509	537	721	235

- per share – diluted [3]	1.12	1.05	1.24	0.91	0.85	0.68	0.71	0.96	0.31
Operating Earnings [2]	332	303	395	209	147	156	143	353	169
- per share – diluted [3]	0.44	0.40	0.52	0.28	0.19	0.21	0.19	0.47	0.23
Net Earnings	266	510	655	47	78	295	183	525	42
- per share – basic [3]	0.35	0.68	0.87	0.06	0.10	0.39	0.24	0.70	0.06
- per share – diluted [3]	0.35	0.67	0.86	0.06	0.10	0.39	0.24	0.70	0.06
Capital Investment [4]	903	631	476	713	701	479	444	491	507
Cash Dividends [5]	151	150	151	151	151	150	150	150	159
- per share [5]	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	US$0.20

[1] In the fourth quarter of 2009, realized and unrealized financial hedging gains from revenue of $35 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.
[2] Non-GAAP measures defined within this MD&A.
[3] Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the Arrangement which is further explained in the Advisory.
[4] Includes expenditures on PP&E and E&E assets.
[5] The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

The improvements in our operational and financial results in the fourth quarter of 2011 demonstrated the dedication of our teams throughout the year. In the fourth quarter, we completed the coker construction and start up activities of the CORE project construction at the Wood River Refinery, more than doubled production from Christina Lake and Lower Shaunavon compared to the fourth quarter of 2010 and completed our 2011 capital program despite the impacts of wet weather in the second and third quarters.

In the fourth quarter of 2011, coker construction and start up activities of the CORE project at the Wood River Refinery were completed. The initial CORE design included increasing nameplate refining capacity by 50,000 barrels per day and doubling heavy crude oil refining capacity to approximately 240,000 barrels per day, enhancing our ability to integrate our growing bitumen production. Total CORE project construction costs are within 10 percent of its original budget.

Our crude oil and NGLs fourth quarter production increased by 11 percent compared to the same period in 2010 due to increased production from Christina Lake, Foster Creek and at our Conventional light and medium crude oil properties. Partially offsetting these increases was the expected natural declines at Pelican Lake and at our Conventional heavy oil properties. The increase in production at Christina Lake was mainly due to the start of production at phase C in the third quarter of 2011.

We applied for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities to Christina Lake, increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G.

Natural gas production in the fourth quarter of 2011 was 660 MMcf per day, a decrease of four percent from 2010 due to expected declines in production from limited capital investment.

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Capital investment in the fourth quarter of 2011 was $903 million, an increase of $202 million from 2010. The fourth quarter was extremely busy with activity at three phases at Foster Creek, three phases at Christina Lake and our drilling and completions programs across the other areas.

Operating cash flow increased $204 million in the fourth quarter of 2011 primarily due to crude oil and NGLs increasing $157 million due to higher average sales prices and sales volumes. Refining and Marketing operating cash flow increased $113 million attributable to improved refining margins. The $64 million decrease in operating cash flow from natural gas was consistent with lower production volumes and average sales prices.

In the fourth quarter of 2011 our cash flow increased $206 million compared to 2010 primarily due to:
- A 28 percent increase in the average sales price of crude oil and NGLs to $80.50 per barrel;
- An increase in operating cash flow from Refining and Marketing of $113 million, mainly due to improved refining margins; and
- An increase in our crude oil and NGLs sales volumes consistent with the 11 percent increase in production volumes primarily related to Christina Lake, conventional light and medium crude oil and Foster Creek.

The increases in our cash flow in the fourth quarter of 2011 were partially offset by:
- Increased operating expenses, primarily from crude oil and NGLs production, due to higher staffing levels at Foster Creek, Christina Lake and Pelican Lake, increased trucking and fluid hauling costs with increased production at Bakken and Lower Shaunavon and higher electricity and workover costs;
- Realized risk management gains before tax, excluding Refining and Marketing, of $29 million compared to gains of $79 million in 2010;
- An increase in royalties of $43 million mainly as a result of higher crude oil production and increases to the Canadian dollar equivalent WTI price used to calculate certain royalty rates;
- A $29 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- A six percent decrease in the average natural gas sales price to $3.35 per Mcf; and
- Natural gas production declining four percent (28 MMcf per day), as a result of lower capital investment and expected natural declines.

In the fourth quarter of 2011, our net earnings increased $188 million compared to 2010. The factors discussed above that increased our operating cash flow in the fourth quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 fourth quarter net earnings include:
- Unrealized risk management losses, after-tax, of $180 million, compared to losses of $197 million in the fourth quarter of 2010;
- A gain of $104 million on the divesture of a non-core asset in the fourth quarter of 2011 compared to the fourth quarter of 2010 when we recognized a loss of $3 million;
- Increased DD&A expense of $59 million primarily due to a $45 million refining asset impairment in the fourth quarter of 2011; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, of $150 million, compared to $75 million in 2010.

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 contingent and prospective bitumen 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 oil and 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.

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Highlights in 2011 include:

- Bitumen proved reserves increased approximately 26 percent and proved plus probable reserves increased approximately 16 percent;
  - Christina Lake added proved reserves of 270 million barrels while proved plus probable reserves increased by 213 million barrels. Increases at Christina Lake were primarily a result of receiving regulatory approval to expand the development area and from positive delineation results;
  - Foster Creek added proved reserves of 56 million barrels and proved plus probable reserves of 79 million barrels. Increases at Foster Creek were primarily due to positive revisions from delineation results, increased recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Heavy oil proved reserves increased approximately four percent and proved plus probable reserves increased approximately seven percent. These increases were primarily as a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium oil and NGLs proved and proved plus probable reserves each increased by approximately four percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and the successful performance of those flood areas at Weyburn;
- Natural gas proved reserves declined approximately 13 percent and proved plus probable reserves declined approximately 11 percent due to extensions and technical revisions not offsetting production and due to the impacts of declined capital investment;
- Best estimate economic contingent resources increased 2.1 billion barrels or approximately 34 percent. This increase is primarily as a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources and positive technical revisions to volumetric and recovery factor estimates;
- Best estimate prospective resources declined 2.3 billion barrels or approximately 19 percent, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling.

The reserves and resources data is presented as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs and as at December 31, 2010 using McDaniel's January 1, 2011 forecast prices and costs. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalty volumes presented below do not include reserves associated with this production.

RESERVES AT DECEMBER 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Proved	**1,455**	1,154	**175**	169	**115**	111	**1,203**	1,390
Probable	**490**	523	**109**	97	**51**	49	**391**	410
Proved plus Probable	**1,945**	1,677	**284**	266	**166**	160	**1,594**	1,800

RECONCILIATION OF PROVED RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2010	1,154	169	111	1,390
Extensions and Improved Recovery	256	16	13	50
Discoveries	-	-	-	-
Technical Revisions	69	2	1	29
Economic Factors	-	1	-	(28)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production	(24)	(13)	(10)	(238)
December 31, 2011	1,455	175	115	1,203
Year over year change	301	6	4	(187)
	26%	4%	4%	-13%

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RECONCILIATION OF PROBABLE RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2010	523	97	49	410
Extensions and Improved Recovery	32	14	3	11
Discoveries	-	-	-	-
Technical Revisions	(65)	(2)	(1)	(27)
Economic Factors	-	-	-	(3)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production	-	-	-	-
December 31, 2011	490	109	51	391
Year over year change	(33)	12	2	(19)
	-6%	12%	4%	-5%

ECONOMIC CONTINGENT and PROSPECTIVE RESOURCES AT DECEMBER 31

	Bitumen (billions of barrels)	
Before Royalties	**2011**	2010
Economic contingent resources[1]		
Low Estimate	**6.0**	4.4
Best Estimate	**8.2**	6.1

High Estimate	**10.8**	8.0
Prospective resources[1][2]		
Low Estimate	**5.7**	7.3
Best Estimate	**10.0**	12.3
High Estimate	**17.9**	21.7

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and low, best and high estimate. 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. The contingencies applicable to our contingent resources are not categorized as economic. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican.

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 for expansion of the Christina Lake development area resulted in the movement of some contingent resources to proved and probable reserves.

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Similarly, the stratigraphic test well program in the Borealis and Pelican Lake Regions 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.

Bitumen reserves and resources increased in part because of improvements in SAGD performance at our Foster Creek and Christina Lake properties resulting from improved operating performance and the use of wells drilled using our Wedge Well™ technology. 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 Annual Information Form ("AIF") for the year ended December 31, 2011 (see the Additional Information section).

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Net cash from (used in)			
Operating activities	**$ 3,273**	$ 2,591	$ 3,039
Investing activities	**(2,530)**	(1,793)	(2,063)
Net cash provided (used) before Financing activities	**743**	798	976
Financing activities	**(558)**	(631)	(977)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**10**	(22)	(32)
Increase (decrease) in cash and cash equivalents	**$ 195**	$ 145	$ (33)

OPERATING ACTIVITIES

Cash from operating activities increased $682 million in 2011 compared to 2010 mainly because of an $864 million increase in cash flow, which is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in non-cash working capital and the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets held for sale, we had working capital of $283 million at December 31, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet our payment obligations.

INVESTING ACTIVITIES

Cash used for investing activities in 2011 increased $737 million from 2010. The increase is primarily due to higher capital expenditures, which increased by $591 million and decreased proceeds from divestiture of assets of $136 million. Capital expenditures are further discussed under Net Capital Investment within the Financial Information section and Capital Investment within the Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

In September 2011, we renegotiated our existing $2.5 billion committed bank credit facility, increasing the facility to $3.0 billion and extending the maturity date to November 30, 2015. In addition, the standby fees required to maintain the facility and the cost of future borrowings were reduced. We also have a commercial paper program which, together with the committed credit facility, may be used to manage our short-term cash requirements. At December 31, 2011, we had no short-term borrowings (2010 and 2009 – nil) in the form of commercial paper. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus. The Canadian debt shelf prospectus expires in July 2012 and the U.S. debt shelf prospectus in August 2012. It is our intention to renew both prospectuses prior to their expiration.

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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 then finally to growth capital. In 2011, we declared and paid quarterly dividends of $0.20 per share (2010 – $0.20 per share; 2009 – US$0.20 per share in the fourth quarter) for total dividend payments of $603 million (2010 - $601 million; 2009 - $159 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2011 decreased by $73 million from 2010. The decrease in 2011 was primarily due to $58 million of revolving long-term debt payments in 2010 compared to none in 2011 and higher proceeds on the issuance of common shares in 2011, which were as a result of stock option exercises. Our long-term debt was $3,527 million as at December 31, 2011 (2010 - $3,432 million; 2009 - $3,656 million). There are no payments of principal due until September 2014 ($814 million).

As at December 31, 2011, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	December 31,		
	2011	2010	2009
Debt to Capitalization	**27%**	29%	32% [1]
Debt to Adjusted EBITDA (times)	**1.0x**	1.3x	0.9x [2]

[1] The 2009 Debt to Capitalization ratio has been calculated as at January 1, 2010 on an IFRS basis.
[2] The 2009 Debt to Adjusted EBITDA ratio has been calculated on a previous GAAP basis.

In 2011, driven by strong operational results, our financial position has improved as measured by our debt to capitalization and debt to adjusted EBITDA metrics both of which are at or below the low end of our target ranges.

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 our non-GAAP measure of capitalization as debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before finance costs, interest income, income tax expense, DD&A, 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 as measures of our overall financial strength.

In order to increase comparability of debt to adjusted EBITDA between periods and remove the non-cash component of risk management activities, we changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for 2010 and 2009 have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

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

OUTSTANDING SHARE DATA

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. As at December 31, 2011, approximately 754.5 million common shares were outstanding (2010 – 752.7 million; 2009 – 751.3 million) and no preferred shares were outstanding. The increase in common shares in 2011 was the result of stock option exercises. No other issuance of common shares has occurred in 2011.

We have in place a Board approved dividend reinvestment plan ("DRIP"), which permits holders of common shares to automatically reinvest all or any portion of their cash dividends paid on their common shares in additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the years ended December 31, 2011 and 2010, common shares were purchased on the market to meet our DRIP requirements.

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Long-term Incentive Plans

The Cenovus Stock Option Plan ("ESOP") permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our common shares. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the ESOP 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 granted prior to February 24, 2011 have an associated tandem share appreciation right ("TSAR"), which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our common shares over the exercise period of their option in exchange for surrendering their option. A portion of the options have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. The performance-based options that do not vest when eligible are forfeited. The exercise of an option as a TSAR for a cash payment does not result in the issuance of any additional common shares, thus having no dilutive effect.

Options granted on or after February 24, 2011 have associated net settlement rights ("NSR"). The NSRs, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of our common shares at the time of exercise over the exercise price

of the option.

The TSARs and NSRs vest and expire under the same terms and conditions as the underlying options.

In accordance with the Arrangement, each Cenovus and Encana employee holding Encana options prior to the Arrangement received one Cenovus replacement option and one Encana replacement option for each original Encana option held. The terms and conditions of the Cenovus replacement options are similar to the terms and conditions of the original Encana options, which are also similar to the terms and conditions of Cenovus options. The original exercise price of the Encana options was apportioned to the Cenovus and Encana replacement options based on the one-day weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the Toronto Stock Exchange on December 2, 2009.

No further Cenovus replacement options will be granted to Encana employees. Encana is required to reimburse Cenovus in respect of cash payments made to Encana employees for Cenovus replacement options exercised as TSARs. Cenovus is required to reimburse Encana in respect of cash payments made to Cenovus employees for Encana replacement options exercised as TSARs. No further Encana replacement options will be granted to Cenovus employees.

The following is a summary of long-term incentives outstanding at year end:

	2011		2010		2009	
	Units[1]	Price[2]	Units[1]	Price[2]	Units[1]	Price[2]
TSARs						
- outstanding	**14,921**	**$ 28.12**	19,117	$ 27.75	16,455	$ 27.52
- exercisable	**8,874**	**$ 29.15**	7,734	$ 28.07	6,107	$ 25.68
NSRs						
- outstanding	**5,809**	**$ 36.95**	-	-	-	-
- exercisable	**1**	**$ 37.54**	-	-	-	-
Cenovus Replacement TSARs [3]						
- outstanding	**9,686**	**$ 28.96**	17,154	$ 28.16	22,945	$ 27.14
- exercisable	**7,522**	**$ 29.73**	10,805	$ 27.88	9,972	$ 25.29
Encana Replacement TSARs [4]						
- outstanding	**10,411**	**$ 31.97**	13,527	$ 31.17	16,357	$ 30.46
- exercisable	**8,461**	**$ 32.64**	8,066	$ 30.85	6,076	$ 28.43

[1] Thousands of units.
[2] Weighted average exercise price.
[3] Held by Encana Employees.
[4] Held by Cenovus Employees.

The closing share price at December 31, 2011 for Cenovus was $33.83 and for Encana was $18.89.

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CONTRACTUAL OBLIGATIONS AND COMMITMENTS

	Expected Payment Date						
($ millions)	2012	2013	2014	2015	2016	2017+	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
Decommissioning liabilities	69	2	7	2	2	6,458	6,540
Long-term debt [3]	-	-	814	-	-	2,745	3,559
Partnership Contribution Payable [3]	372	395	419	445	472	122	2,225
Total Payments [4]	$ 1,045	$ 747	$ 1,572	$ 881	$ 929	$ 13,591	$ 18,765
Product Sales	$ 52	$ 54	$ 56	$ 57	$ 60	$ 3	$ 282
Partnership Contribution Receivable [3]	$ 372	$ 393	$ 414	$ 436	$ 460	$ 119	$ 2,194

[1] Certain transportation commitments included are subject to regulatory approval.
[2] Includes commitments related to jointly controlled entities.
[3] Principal component only. See notes to the Consolidated Financial Statements.
[4] Contracts undertaken by the Company on behalf of the FCCL Partnership 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), future building leases, marketing agreements, capital commitments and debt. 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.

Our commitments for 2012 increased by $385 million and in total increased by $2,537 million from 2010 mainly due to increased pipeline transportation commitments. These increased commitments were primarily for increased tolls and new agreements entered into in 2011 for crude oil transportation as we implement our marketing strategy to access new markets for our increasing crude oil production.

As at December 31, 2011, 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 61 Bcf of natural gas at a weighted average price of $4.62 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.

RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:
- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk, liquidity risk and cost overruns;
- Operational risks including capital and operating risks, reserves replacement risks and safety and environmental risks; and

· Regulatory risks including regulatory process and approval risks and changes to environmental regulations.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Management monitors our risk strategies to proactively respond to changing economic conditions and to eliminate or mitigate risk. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

A description of the risks 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, 2011 (see Additional Information).

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FINANCIAL RISKS

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient access to cash resources, including our committed credit facility, is maintained to fund capital expenditures.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of December 31, 2011, are disclosed in the notes to the Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

Global Economic Environment

The global economic environment has been turbulent and there continues to be uncertainty surrounding the European sovereign debt crisis. The European financial conditions along with a potential U.S. recession are among our most significant economic concerns.

We believe our financial position is strong with debt metrics currently at or below the low end of our target ranges. In addition, we have a fully available committed credit facility of $3.0 billion and capacity under two shelf prospectuses available to assist in addressing continued economic uncertainty and deteriorating global conditions. We also have a risk mitigation strategy that helps protect a portion of our cash flow each year.

Our ability to react to global economic uncertainties is enhanced by our ability to scale our capital programs to accommodate reduced cash flows.

Commodity Price Risk

Commodity price risk is the exposure to fluctuations in future market prices that results from the sales of various commodities in our operations.

We seek to reduce our exposure to commodity price risk through an integrated business strategy whereby a portion of operating supplies and feedstock is provided from internal operations. To further mitigate commodity price risk, we use derivative instruments in various operational markets to optimize our supply or production chain. We have partially mitigated our exposure to the crude oil commodity price risk on our crude oil sales with fixed price WTI swaps. We have partially mitigated our exposure to the natural gas commodity price risk on our natural gas sales with fixed price NYMEX and AECO swaps. We have partially mitigated our exposure to widening location or quality differentials for crude oil and natural gas with fixed price differential and basis swaps. We have partially mitigated our exposure to electricity consumption costs with a derivative power contract.

Credit Risk

Credit risk is the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms.

A substantial portion of our accounts receivable are with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policy governing our credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All financial derivative agreements are with major financial institutions in North America and Europe or with counterparties having investment grade credit ratings.

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.

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, 2011, no amounts were drawn on our committed credit facility.

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In addition, we had $1.5 billion in unused capacity under our Canadian shelf prospectus and US$1.5 billion in unused capacity under our U.S. shelf prospectus, the availability of which are dependent on market conditions. Both of these prospectuses expire in the third quarter of 2012 and it is our intention to renew them prior to their expiration.

Foreign Exchange Risk

Foreign exchange risk is the exposure to fluctuations in foreign currency exchange rates in our operations. As our commodity sales are generally priced in U.S. dollars and our capital expenditures and expenses are paid in both U.S. and Canadian dollars, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a

significant effect on our financial results which are reported in Canadian dollars.

We reduce our exposure to foreign exchange risk through an integrated business strategy with a mix of U.S. and Canadian operations that creates a partial hedge to foreign exchange exposure. To further mitigate foreign exchange risk, we may enter into foreign exchange contracts or hedge our commodity exposures in Canadian dollars.

We also have the flexibility to maintain a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, we may enter into cross currency swaps on a portion of our debt as a means of managing the U.S./Canadian dollar debt mix.

Interest Rate Risk

Interest rate risk is the impact of changing interest rates on earnings, cash flows and valuations. Although all of our debt portfolio was fixed rate debt at December 31, 2011, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our commercial paper program and credit facilities. We may also enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Capital and Operating Risks

Our ability to operate, generate cash flows, complete projects and value reserves is subject to capital and operating risks, including continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary regulatory, stakeholder and partner approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour and reservoir quality.

In the context of continued market volatility and in the face of the European credit crisis, which could result in a significant global economic recession, we are mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and we identified areas where we could slow down our spending in response to lower cash flows due to lower market prices. We expect to maintain strong financial metrics and substantial liquidity to respond to periods of lower prices if recessionary pressures impact our business.

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 and, therefore, our cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, 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. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these look back results are analyzed in relation to our capital program with the results and identified learnings shared across our company.

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We utilize a peer review process to ensure that capital projects are appropriately risked and that knowledge is shared across our company. Peer reviews are undertaken primarily for early stage properties, although they may occur for any type of project.

Safety and Environmental Risk

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or unanticipated environmental disruption. We are committed to safety in our operations and with high regard for the environment and stakeholders. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, we maintain a system, in respect of our assets and operations that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to both senior management and our Board. The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including safety and the environment, for approval by our Board 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, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

We have an Investigations Committee whose mandate is to address potential violations of policies and practices and an Integrity Helpline that can be used to raise any concerns regarding operations, accounting or internal control matters.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

REGULATORY RISKS

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 the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by our operating and corporate groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. Of note in this regard, our approach to changes in regulations relating to climate change, royalty and regulatory frameworks is discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives mentioned herein.

Environmental Regulation Risk

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

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. This regulation currently differentiates oil sands crudes as high carbon intensity crude oils. As an oil sands producer, we are not directly regulated and will not have a compliance obligation; however, refiners in California will be required to meet the legislation. A number of studies produced on the subject, including one that was conducted by an organization that advised the legislation, suggest a wide range of carbon intensity values for oil sands crudes. We are well positioned within the sector given our typically low steam to oil ratio.

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This legislation has many complexities that are currently being addressed and in December 2011 the U.S. District Court for the Eastern District of California temporarily suspended the enforcement of the legislation due to several pending federal lawsuits challenging its implementation. We continue to monitor this development.

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.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Government of Alberta has set targets for GHG emissions reductions. Regulations require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline. To comply, companies can make operating improvements, purchase carbon offsets (or emission performance credits) or make a $15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus currently has three facilities subject to this regulation. For the 2011 compliance year, we do not anticipate material costs in this regard.

Our efforts with respect to emissions management are founded in our industry leadership in:
- Oil sands technology development to reduce GHG emissions;
- Focus on energy efficiency; and
- Carbon dioxide sequestration.

In particular, our low steam to oil ratios at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

(1) Manage Existing Costs
When regulations are implemented, a cost is placed on our emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.

(2) Respond to Price Signals
As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon reduction, we are also attempting, where appropriate, to realize associated value of our reduction projects.

(3) Anticipate Future Carbon Constrained Scenarios
We continue to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios assist with our long range planning and our analyses on the implications of regulatory trends.

We incorporate the potential costs of carbon into 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 to a range of emissions coverage levels. 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. We also examine the impact of carbon regulation on our major projects. Although uncertainty remains regarding potential future emissions regulation, our plan is to continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We recognize that there is a cost associated with carbon emissions. We believe that GHG regulations and the cost of carbon at various price levels have been adequately taken into consideration as part of our business planning and scenarios analysis. We believe that our development strategy, use of technology and focus on continuous improvement is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect our operations.

Further information regarding Climate Change can be found in the Risk Factors section of our AIF for the year ended December 31, 2011 (see Additional Information).

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ALBERTA'S REGULATORY FRAMEWORK

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. An updated draft of the LARP was released on August 29, 2011 after public consultation and stakeholder feedback was obtained. No substantial changes were made to the LARP from these consultations. The LARP is now awaiting provincial cabinet approval prior to being implemented.

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. If the land use designations for conservation, tourism and recreation areas are approved in their current form, 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 that may adversely affect the market price of our securities and the payment of dividends to our shareholders. 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.

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 accepted the Project team's recommendations and decided to proceed in implementing those recommendations. There were no new developments in 2011.

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Water. 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.

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 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. In July 2011 we released our first comprehensive corporate responsibility report which 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.

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ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates 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 information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to understanding our financial results.

Basis of Presentation

Our results for the years ended December 31, 2011 and 2010 and the one month period from December 1, 2009 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

Our results for the period prior to the Arrangement, being January 1, 2009 to November 30, 2009, have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. The historical consolidated financial statements include allocations of certain Encana expenses, assets and liabilities. In the opinion of management, the consolidated and historical carve-out consolidated financial statements reflect all adjustments necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with previous GAAP.

Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of Encana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the period presented.

Oil and Gas Reserves

All of our oil and gas reserves were evaluated and reported to Cenovus by the IQREs as at December 31, 2011 in accordance with NI 51-101. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results

of future drilling, testing, production levels, and economics of recovery based on cash flow forecasts. These revisions can have a significant impact on our future earnings because they will directly impact our DD&A rates, asset impairment calculations, accounting for business combinations and decommissioning costs.

Property, Plant and Equipment – DD&A

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit of production method based on estimated proved reserves determined using estimated future prices and costs. As a key component in the calculation of DD&A, the estimates of reserves can have a significant impact on net earnings, as a downward revision in our estimate of reserve quantities could result in a higher DD&A charge to net earnings.

Refining, marketing, corporate and other upstream assets, including pipelines and information technology assets, are depreciated on straight-line basis and are subject to our estimate of useful life and salvage value. These estimates can have a significant impact to net earnings as a decrease in the useful life or a lower salvage value could result in a higher DD&A charge to net earnings.

E&E Assets

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material change in the future.

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Impairment of 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 impairment test is performed at the cash generating unit ("CGU") for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets. Corporate assets are allocated on a reasonable and consistent manner to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. For refining assets the impairment test is performed at each refinery independently.

The assessment of facts and circumstances that are used for impairment testing to suggest that the carrying amount of the assets may exceed its recoverable amount is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or CGUs for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The recoverable amount calculation requires the use of estimates and assumptions which are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs. Details on the assumptions used in determining the recoverable amount can be found in the notes to the Consolidated Financial Statements.

Exchanges of Assets

Fair value estimates, which are used to determine the carrying value of a PP&E or E&E asset and recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

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. 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.

Decommissioning Liabilities

Provisions are recognized for the future decommissioning and restoration of our upstream oil and gas assets and refining assets at the end of their economic lives. Assumptions, based on current economic factors and experience to date which we believe are reasonable, have been made to estimate the future liability. 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. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, we determine 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. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

Compensation Plans

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to our best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under our compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

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Income Tax Provisions

Tax regulations and legislations and their interpretations in the various jurisdictions that we operate 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. 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.

Financial Instruments

The fair value of derivatives, which may be used to manage commodity price, foreign currency and interest rate exposures, are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Our assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and are therefore subject to measurement uncertainty.

IFRS Transition

OPENING BALANCE SHEET – CARRYING VALUE OF REFINERIES

On transition to IFRS, we elected to measure the carrying value of our refineries at their then estimated fair value, which permanently reduced their carrying value by approximately $2.6 billion. The fair value estimate is deemed to be the carrying value of the refineries at January 1, 2010. The reduced carrying value impacts DD&A expense recorded in future periods. DD&A expense for the year ended December 31, 2010 was reduced by $103 million as a result of the reduced carrying value.

OPENING BALANCE SHEET – FULL COST POOL

Under previous GAAP, we accounted for our oil and gas properties in one cost centre using full cost accounting. IFRS has no equivalent treatment. IFRS 1 - First-time Adoption of IFRS, permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Applying this exemption, the cost of our E&E assets were reclassified from PP&E to the new E&E asset category, and the remainder of our full cost pool was allocated using the estimated proved reserve values discounted at 10 percent at the transition date. This approach was consistent with the allocation method which was required to be used in our formation as part of the Arrangement. The IFRS allocation process did not affect the net book value of our PP&E at the date of transition as no IFRS impairments were recognized.

Under both IFRS and previous GAAP, the DD&A on our development and production PP&E is calculated using the unit-of-production method based on estimated proved reserves. However, under previous GAAP, we calculated our DD&A rate at the country cost centre level whereas under IFRS, our DD&A rates are calculated at the area level. The adoption of this policy resulted in a $135 million increase in our DD&A for the year ended December 31, 2010.

FUTURE CHANGES IN ACCOUNTING POLICIES

Joint Arrangements and Off Balance Sheet Activities

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 and focuses on the need to have power and variable returns for control to be present. 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"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement.

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A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts 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. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- *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. Early adoption is permitted, providing the five standards are adopted concurrently. We are currently evaluating the impact of adopting these standards on our Consolidated Financial Statements.

Employee Benefits

In June 2011, the IASB amended *IAS 19, "Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates and the valuation of plan assets, will be recognized in OCI. Furthermore, 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 amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting these amendments on our Consolidated Financial Statements.

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. We are currently evaluating the impact of adopting IFRS 13 on our 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. We are currently evaluating the impact of adopting IFRS 9 on our Consolidated Financial Statements.

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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. We are currently evaluating the impact of adopting this amendment on our 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. We are currently evaluating the impact of adopting the amendments to IAS 7 and IFRS 32 on our Consolidated Financial Statements.

OUTLOOK

In early 2012, certain economic factors have created optimism that the U.S. economy will gradually improve throughout the year. However, the European sovereign debt situation is expected to continue and may inhibit the North American economic recovery. Our outlook for 2012 depends on commodity prices including the effect of new market access for North American crude oil. Crude oil prices are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

For 2012, the price of WTI is expected to remain close to the average in 2011 as increased demand driven by emerging markets is anticipated to be offset by the return of Libyan supply. The expected increase in demand however remains sensitive to events in Europe as its sovereign debt problems continues to unfold. Also, the potential of further political uncertainty in Middle Eastern and northern African countries could create a material risk of supply disruptions which would negate the effect of returning Libyan supply.

For 2012, the WTI-WCS differential is expected to face pressures to narrow compared to 2011 as new coking capacity at our Wood River Refinery will be in operation for the full year and other additional refining capacity is brought on in the latter part of the year. These pressures are expected to be offset by growing North American crude oil production which will lead to greater pipeline congestion. However, new rail capacity, especially out of North Dakota, will serve to reduce pipeline congestion.

The economics for U.S. Midwest refineries for 2012 are expected to be lower than 2011 as average crack spreads decrease. The expected decrease in crack spreads is mostly due to lower discounts on feedstock costs as inland crude oil finds an outlet to refineries on the Gulf of Mexico through the Seaway Pipeline reversal in the middle of 2012.

For 2012 our strategic initiatives and key priorities include:

- Growth of production at Christina Lake with ramp up of phase C production and expected first production at phase D in the fourth quarter of 2012;
- Conventional crude oil production increasing in 2012 primarily as a result of the development of our tight oil opportunities at Lower Shaunavon and Bakken while pursuing additional growth opportunities;
- Improved production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Investment in the dewatering pilot project at Telephone Lake and the drilling of a second well pair as part of the Grand Rapids pilot project;
- Progressing the Telephone Lake and area project;
- Anticipating regulatory and partner approval for Narrows Lake phases A, B and C, perform additional engineering and start construction;
- Committing to transportation initiatives and advance new and expanded market development initiatives for our crude oil in step with a marketing strategy to deliver on our production growth;
- Progressing environmental strategy by setting internal goals;
- Demonstrating stable and reliable CORE operations at the Wood River Refinery; and
- Growing our dividend, at the discretion of our Board, while continuing to invest in long-term projects.

While we do not anticipate a significant impact to our business, our partner ConocoPhillips, announced its intention to split its Refining and Marketing and its Exploration and Production businesses into two stand-alone companies. If the split is completed, we expect our partnership and related agreements with ConocoPhillips to be amended to accommodate the separation and holding of the upstream assets and refining assets in two separate companies.

Our long-term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:
- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- 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, emphasis on environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core assets with any incremental cash requirements covered by additional debt financing;
- Lowering our commodity price risk profile through natural gas and refining integration as well as a consistent risk management hedging strategy; and
- Maintain a sustainable dividend with a priority expected to be placed on growing the dividend as part of delivering a solid total shareholder return.

Our updated business plan outlines our targets of reaching net oil sands 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. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, access to markets, 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.

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. We will continue to develop our strategy with respect to capital investment and returns to shareholders. 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”, “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 including technology and procedures to reduce our environmental impact 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; the estimation 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; 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; the ability of us and ConocoPhillips to maintain our relationship 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 Alberta’s regulatory framework, 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/Form 40-F for the year ended December 31, 2011 (see Additional Information).

OIL AND GAS INFORMATION

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2011 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. The estimates were based on 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. 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 section.

- 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 2011 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.

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- 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 confidence level 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 at the low end of the estimate range have the highest degree of certainty, a 90 percent confidence level, 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 at the high end of the estimate range have a lower degree of certainty, a 10 percent confidence level, that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated on a project level. The high and low estimates are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. The aggregated low estimate results shown may have a higher level of confidence than the individual projects, and the aggregated high estimate results shown may have a lower level of confidence than the individual projects.

Additional information relating to our oil and gas reserves and resources is presented in our AIF for the year ended December 31, 2011 (see Additional Information).

ABBREVIATIONS

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

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
WTI	West Texas Intermediate
WCS	Western Canadian Select
TM	Trademark of Cenovus Energy Inc.

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	Gigajoule
CBM	Coal Bed Methane

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as cash flow, operating cash flow, free cash flow, operating earnings, adjusted EBITDA, debt and capitalization 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 this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. 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 this MD&A.

ADDITIONAL INFORMATION

The Arrangement refers to the plan of arrangement with Encana Corporation, effective November 30, 2009, resulting in the split of Encana into Cenovus and Encana, whereby Encana shareholders received, for each Encana common share held, one common share of each of Cenovus and the new Encana. Pursuant to the Arrangement, Cenovus commenced independent operations on December 1, 2009.

For convenience, references in this document to the "Company", "Cenovus", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("subsidiaries") of Cenovus, and the assets, activities and initiatives of such subsidiaries.

Additional information relating to Cenovus, including our AIF/Form 40-F for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.

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Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2011

(Canadian Dollars)

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Report of Management

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. ("Cenovus") 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, 2011. 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, 2011.

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, 2011 as stated in their Auditor's Report dated February 15, 2012. PricewaterhouseCoopers LLP has provided such opinions.

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

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

February 15, 2012

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Independent Auditor's Report

To the Shareholders of Cenovus Energy Inc.

We have completed an integrated audit of Cenovus Energy Inc.'s 2011 consolidated financial statements and its internal control over financial reporting as at December 31, 2011 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, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of earnings and comprehensive income, shareholders' equity and cash flows for the years ended December 31, 2011 and 2010, 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, 2011, December 31, 2010 and January 1, 2010 and its financial performance and cash flows for the years ended December 31, 2011 and 2010 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, 2011, 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 Management's Assessment of Internal Controls over Financial Reporting.

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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, 2011 based on criteria established in Internal Control–Integrated Framework, issued by COSO.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada

February 15, 2012

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CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

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

	Notes	2011	2010*
Revenues	1		
Gross Sales		16,185	13,090
Less: Royalties		489	449
		15,696	12,641
Expenses	1		
Purchased product		9,090	7,551
Transportation and blending		1,369	1,065
Operating		1,406	1,286
Production and mineral taxes		36	34
(Gain) loss on risk management	31	(248)	(324)
Depreciation, depletion and amortization		1,295	1,302
Exploration expense		-	3
General and administrative		295	246
Finance costs	5	447	498
Interest income	6	(124)	(144)
Foreign exchange (gain) loss, net	7	26	(51)
(Gain) loss on divestiture of assets	17	(107)	(116)
Other (income) loss, net		4	(13)
Earnings Before Income Tax		2,207	1,304
Income tax expense	8	729	223
Net Earnings		1,478	1,081
Other Comprehensive Income (Loss), Net of Tax			
Foreign currency translation adjustment		48	71
Comprehensive Income		1,526	1,152
Net Earnings per Common Share	9		
Basic		1.96	1.44
Diluted		1.95	1.43

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

As at
($ millions)

	Notes	December 31, 2011	December 31, 2010*	January 1, 2010*
Assets				
Current Assets				
Cash and cash equivalents	10	495	300	155
Accounts receivable and accrued revenues	11	1,405	1,059	982
Income tax receivable		-	31	40
Current portion of Partnership Contribution Receivable	12	372	346	345
Inventories	13	1,291	880	875
Risk management	31	232	163	60
Assets held for sale	14	116	65	-
Current Assets		3,911	2,844	2,457
Exploration and Evaluation Assets	1,15	880	713	580
Property, Plant and Equipment, net	1,16	14,324	12,627	12,049
Partnership Contribution Receivable	12	1,822	2,145	2,621
Risk Management	31	52	43	1
Income Tax Receivable		29	-	-
Other Assets	18	44	281	192
Deferred Income Taxes	8	-	55	3
Goodwill	1,19	1,132	1,132	1,146
Total Assets		22,194	19,840	19,049
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts payable and accrued liabilities	20	2,579	1,843	1,605

Income tax payable		**329**	154	-
Current portion of Partnership Contribution Payable	12	**372**	343	340
Risk management	31	**54**	163	70
Liabilities related to assets held for sale	14	**54**	7	-
Current Liabilities		**3,388**	2,510	2,015
Long-Term Debt	21	**3,527**	3,432	3,656
Partnership Contribution Payable	12	**1,853**	2,176	2,650
Risk Management	31	**14**	10	4
Decommissioning Liabilities	22	**1,777**	1,399	1,185
Other Liabilities	23	**128**	346	246
Deferred Income Taxes	8	**2,101**	1,572	1,484
Total Liabilities		**12,788**	11,445	11,240
Commitments and Contingencies	33			
Shareholders' Equity		**9,406**	8,395	7,809
Total Liabilities and Shareholders' Equity		**22,194**	19,840	19,049

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board

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

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

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital (Note 25)	Paid in Surplus (Note 25)	Retained Earnings	AOCI**	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**

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.
** Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	2011	2010*
Operating Activities			
Net earnings		**1,478**	1,081
Depreciation, depletion and amortization		**1,295**	1,302
Deferred income taxes	8	**575**	141
Cash tax on divestiture of assets		**13**	-
Unrealized (gain) loss on risk management	31	**(180)**	(46)
Unrealized foreign exchange (gain) loss	7	**(42)**	(69)
(Gain) loss on divestiture of assets	17	**(107)**	(116)

Unwinding of discount on decommissioning liabilities	5,22	**75**	75
Other		**169**	44
		3,276	2,412
Net change in other assets and liabilities		**(82)**	(55)
Net change in non-cash working capital		**79**	234
Cash From Operating Activities		**3,273**	2,591
Investing Activities			
Capital expenditures – exploration and evaluation assets	15	**(527)**	(350)
Capital expenditures – property, plant and equipment	16	**(2,265)**	(1,851)
Proceeds from divestiture of assets		**173**	309
Cash tax on divestiture of assets		**(13)**	-
Net change in investments and other		**(28)**	4
Net change in non-cash working capital		**130**	95
Cash (Used in) Investing Activities		**(2,530)**	(1,793)
Net Cash Provided (Used) before Financing Activities		**743**	798
Financing Activities			
Net issuance (repayment) of short-term borrowings		**(9)**	-
Net issuance (repayment) of revolving long-term debt		**-**	(58)
Proceeds on issuance of common shares		**48**	28
Dividends paid on common shares	9	**(603)**	(601)
Other		**6**	-
Cash From (Used in) Financing Activities		**(558)**	(631)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**10**	(22)
Increase (Decrease) in Cash and Cash Equivalents		**195**	145
Cash and Cash Equivalents, Beginning of Year		**300**	155
Cash and Cash Equivalents, End of Year		**495**	300

* Refer to Note 34 for the impact of adopting IFRS effective January 1, 2010.

See accompanying Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2011

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 #4000, 421 - 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. Information on the Company's basis of presentation for these financial statements is found in Note 2.

The Company's reportable segments are as follows:

- **Oil Sands,** which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. 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, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **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 ConocoPhillips. 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.

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A) Results of Operations - Segment and Operational Information

For the years ended December 31,	Oil Sands		Conventional		Refining and Marketing	
	2011	2010	**2011**	2010	**2011**	2010
Revenues						
Gross Sales	**3,291**	2,702	**2,328**	2,284	**10,625**	8,228
Less: Royalties	**284**	279	**205**	170	**-**	-
	3,007	2,423	**2,123**	2,114	**10,625**	8,228
Expenses						
Purchased product	**-**	-	**-**	-	**9,149**	7,674
Transportation and blending	**1,231**	935	**138**	130	**-**	-
Operating	**438**	367	**488**	434	**481**	488
Production and mineral taxes	**-**	-	**36**	34	**-**	-
(Gain) loss on risk management	**70**	(10)	**(152)**	(258)	**14**	(10)
Operating Cash Flow	**1,268**	1,131	**1,613**	1,774	**981**	76
Depreciation, depletion and amortization	**347**	375	**778**	799	**130**	96
Exploration expense	**-**	3	**-**	-	**-**	-
Segment Income (Loss)	**921**	753	**835**	975	**851**	(20)

For the years ended December 31,	Corporate and Eliminations		Consolidated	
	2011	2010	**2011**	2010
Revenues				
Gross Sales	**(59)**	(124)	**16,185**	13,090
Less: Royalties	**-**	-	**489**	449
	(59)	(124)	**15,696**	12,641
Expenses				
Purchased product	**(59)**	(123)	**9,090**	7,551
Transportation and blending	**-**	-	**1,369**	1,065
Operating	**(1)**	(3)	**1,406**	1,286
Production and mineral taxes	**-**	-	**36**	34
(Gain) loss on risk management	**(180)**	(46)	**(248)**	(324)
	181	48	**4,043**	3,029
Depreciation, depletion and amortization	**40**	32	**1,295**	1,302
Exploration expense	**-**	-	**-**	3
Segment Income (Loss)	**141**	16	**2,748**	1,724
General and administrative	**295**	246	**295**	246
Finance costs	**447**	498	**447**	498
Interest income	**(124)**	(144)	**(124)**	(144)
Foreign exchange (gain) loss, net	**26**	(51)	**26**	(51)
(Gain) loss on divestiture of assets	**(107)**	(116)	**(107)**	(116)
Other (income) loss, net	**4**	(13)	**4**	(13)
	541	420	**541**	420
Earnings Before Income Tax			**2,207**	1,304
Income tax expense			**729**	223
Net Earnings			**1,478**	1,081

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2011

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

As at	Exploration and Evaluation Assets			Property, Plant and Equipment		
	December 31, 2011	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**741**	570	452	**6,224**	5,219	4,870
Conventional	**139**	143	128	**4,668**	4,409	4,645
Refining and Marketing	**-**	-	-	**3,200**	2,853	2,418
Corporate and Eliminations	**-**	-	-	**232**	146	116
Consolidated	**880**	713	580	**14,324**	12,627	12,049

As at	Goodwill			Total Assets		
	December 31, 2011	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Oil Sands	**739**	739	739	**10,524**	9,487	9,426
Conventional	**393**	393	407	**5,566**	5,186	5,453
Refining and Marketing	**-**	-	-	**4,927**	4,282	3,669
Corporate and Eliminations	**-**	-	-	**1,177**	885	501

Consolidated	**1,132**	1,132	1,146	**22,194**	19,840	19,049

Capital Expenditures

For the years ended December 31,	2011	2010
Capital		
Oil Sands	**1,415**	857
Conventional	**788**	526
Refining and Marketing	**393**	656
Corporate	**127**	76
	2,723	2,115
Acquisition Capital		
Oil Sands	**44**	23
Conventional	**25**	25
Refining and Marketing	**-**	38
Corporate	**2**	-
Total	**2,794**	2,201

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, 2011, Cenovus had two customers (2010 – two) which individually accounted for more than 10 percent of its consolidated gross revenues. Sales to these customers, major international integrated energy companies with an investment grade credit rating, were approximately $7,324 million and $2,683 million respectively (2010 – $5,376 million and $2,295 million).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2011

B) Financial Results by Upstream Product

	Crude Oil and NGLs					
	Oil Sands		Conventional		Total	
For the years ended December 31,	2011	2010	2011	2010	2011	2010
Revenues						
Gross Sales	**3,217**	2,610	**1,492**	1,229	**4,709**	3,839
Less: Royalties	**282**	276	**193**	153	**475**	429
	2,935	2,334	**1,299**	1,076	**4,234**	3,410
Expenses						
Transportation and blending	**1,229**	934	**104**	86	**1,333**	1,020
Operating	**409**	339	**244**	199	**653**	538
Production and mineral taxes	**-**	-	**27**	28	**27**	28
(Gain) loss on risk management	**87**	14	**43**	5	**130**	19
Operating Cash Flow	**1,210**	1,047	**881**	758	**2,091**	1,805

	Natural Gas					
	Oil Sands		Conventional		Total	
For the years ended December 31,	2011	2010	2011	2010	2011	2010
Revenues						
Gross Sales	**63**	78	**825**	1,042	**888**	1,120
Less: Royalties	**2**	1	**12**	17	**14**	18
	61	77	**813**	1,025	**874**	1,102
Expenses						
Transportation and blending	**2**	1	**34**	44	**36**	45
Operating	**24**	23	**240**	231	**264**	254
Production and mineral taxes	**-**	-	**9**	6	**9**	6
(Gain) loss on risk management	**(17)**	(24)	**(195)**	(263)	**(212)**	(287)
Operating Cash Flow	**52**	77	**725**	1,007	**777**	1,084

	Other					
	Oil Sands		Conventional		Total	
For the years ended December 31,	2011	2010	2011	2010	2011	2010
Revenues						
Gross Sales	**11**	14	**11**	13	**22**	27
Less: Royalties	**-**	2	**-**	-	**-**	2
	11	12	**11**	13	**22**	25
Expenses						
Transportation and blending	**-**	-	**-**	-	**-**	-
Operating	**5**	5	**4**	4	**9**	9
Production and mineral taxes	**-**	-	**-**	-	**-**	-
(Gain) loss on risk management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**6**	7	**7**	9	**13**	16

	Total	

For the years ended December 31,	Oil Sands 2011	Oil Sands 2010	Conventional 2011	Conventional 2010	Total 2011	Total 2010
Revenues						
Gross Sales	3,291	2,702	2,328	2,284	5,619	4,986
Less: Royalties	284	279	205	170	489	449
	3,007	2,423	2,123	2,114	5,130	4,537
Expenses						
Transportation and blending	1,231	935	138	130	1,369	1,065
Operating	438	367	488	434	926	801
Production and mineral taxes	-	-	36	34	36	34
(Gain) loss on risk management	70	(10)	(152)	(258)	(82)	(268)
Operating Cash Flow	1,268	1,131	1,613	1,774	2,881	2,905

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C) Geographic Information

For the years ended December 31,	Canada 2011	Canada 2010	United States 2011	United States 2010	Consolidated 2011	Consolidated 2010
Revenues						
Gross Sales	7,513	6,466	8,672	6,624	16,185	13,090
Less: Royalties	489	449	-	-	489	449
	7,024	6,017	8,672	6,624	15,696	12,641
Expenses						
Purchased product	1,867	1,456	7,223	6,095	9,090	7,551
Transportation and blending	1,369	1,065	-	-	1,369	1,065
Operating	947	814	459	472	1,406	1,286
Production and mineral taxes	36	34	-	-	36	34
(Gain) loss on risk management	(255)	(322)	7	(2)	(248)	(324)
	3,060	2,970	983	59	4,043	3,029
Depreciation, depletion and amortization	1,165	1,216	130	86	1,295	1,302
Exploration expense	-	3	-	-	-	3
Segment Income (Loss)	1,895	1,751	853	(27)	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 $700 million (2010 – $646 million).

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

As at	Exploration and Evaluation Assets December 31, 2011	Exploration and Evaluation Assets December 31, 2010	Exploration and Evaluation Assets January 1, 2010	Property, Plant and Equipment December 31, 2011	Property, Plant and Equipment December 31, 2010	Property, Plant and Equipment January 1, 2010
Canada	880	713	580	11,124	9,774	9,645
United States	-	-	-	3,200	2,853	2,404
Consolidated	880	713	580	14,324	12,627	12,049

As at	Goodwill December 31, 2011	Goodwill December 31, 2010	Goodwill January 1, 2010	Total Assets December 31, 2011	Total Assets December 31, 2010	Total Assets January 1, 2010
Canada	1,132	1,132	1,146	17,536	15,906	15,669
United States	-	-	-	4,658	3,934	3,380
Consolidated	1,132	1,132	1,146	22,194	19,840	19,049

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 represent the Company's first annual financial statements 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. The Company's accounting policies have been applied consistently to all years presented with the exception of certain IFRS 1, "*First-time Adoption of International Financial Reporting Standards*" ("IFRS 1") transition elections and exemptions the Company applied in its transition from Canadian generally accepted accounting principles ("previous GAAP") as discussed in Note 34. The impact of

the transition to IFRS on the Company's financial position, results of operation and cash flows from the Consolidated Financial Statements for the year ended December 31, 2010 prepared under previous GAAP is included in Note 34.

After applying the transition exemptions of IFRS 1, 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.

The Consolidated Financial Statements of Cenovus were authorized for issuance in accordance with a resolution of the Board of Directors on February 14, 2012.

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 delivered

and the services provided.

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 Costs

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 accumulated costs are expensed as exploration expense.

H) Employee Benefit Plans

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

The cost of pensions and other post-employment benefits is actuarially determined using the projected 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. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

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 ten 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 plans is recorded as the benefits are earned by the employees covered by the plans.

I) Income Taxes

Income taxes comprise current and deferred tax. 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 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, in which case the deferred income tax is also recorded in equity.

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 the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are 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.

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 principally be 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/area/project is determined or the assets are determined to be impaired.

Once technical feasibility and commercial viability have been established for a field/area/project 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/area/project 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.

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 lives of each component of the refineries. 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 lives of each component are reviewed annually and adjusted, if appropriate.

Other Assets

Costs associated with office furniture, fixtures, leasehold improvements, information technology, marine terminal facilities 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. 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. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses 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 Statement 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 and the loss event has an impact on future cash flow and 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 is recognized on a financial asset carried at amortized cost 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 Statement of Earnings and Comprehensive Income.

S) Leases

Leases in which substantially all 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 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 estimated liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to estimated timing or future decommissioning cost estimates 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.

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 tax.

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 the 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 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 the Cenovus 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 Statement 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 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.

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 the 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 at the settlement date using the effective interest method of amortization.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value at the settlement date, with changes in the fair value recognized in other comprehensive income. 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 2011.

AA) Recent Accounting Pronouncements

Joint Arrangements and Off Balance Sheet Activities

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 and focuses on the need to have power and variable returns for control to be present. 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*". IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement.

A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts 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. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- 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. Early adoption is permitted, providing the five standards are adopted concurrently. The Company is currently evaluating the impact of adopting these standards on its Consolidated Financial Statements.

Employee Benefits

In June 2011, the IASB amended IAS 19, "*Employee Benefits*" ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates or the valuation of plan assets, will be recognized in OCI. Furthermore, 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 amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Earlier adoption is permitted. The Company is currently evaluating the impact of adopting these amendments on its Consolidated Financial Statements.

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. The Company is currently evaluating the impact of adopting IFRS 13 on its 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.

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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 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 Company is currently evaluating the impact of adopting this amendment on its 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. The Company is currently evaluating the impact of adopting the amendments to IFRS 7 and IAS 32 on its Consolidated Financial Statements.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

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. Significant judgments, estimates and assumptions made by Management in the preparation of these Consolidated Financial Statements are outlined below.

Carrying Value of Property, Plant and Equipment

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the Consolidated Financial Statements of future periods could be material.

Refining, marketing, other upstream and corporate assets are depreciated on a straight-line basis and are subject to Management's estimate of useful life and salvage value. Changes to the estimated useful life and salvage value could have a material impact on the Consolidated Financial Statements of future periods.

Carrying Value of 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 and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of the Company's upstream oil and 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. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. 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.

Impairment of Assets

The recoverable amounts of CGUs and individual assets have been determined as the greater of an asset's or CGU's value-in-use and fair value less costs to sell. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

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

At December 31, 2011, 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 reserve evaluators, oil and natural gas prices and the discount rate.

Reserves

Reserve estimates are dependent on a number of variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs and estimated selling price of the hydrocarbons produced. Changes in these variables could significantly impact the reserve estimates. The Company's oil and gas reserves are evaluated and reported to the Company by independent qualified reserves evaluators.

Oil and natural gas prices

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

	2012	2013	2014	2015	2016	Average Annual % Change to 2023
WTI (US$/barrel)	97.50	97.50	100.00	100.80	101.70	1.3%
AECO ($/Mcf)	3.50	4.20	4.70	5.10	5.55	3.5%

Discount rate

A discount rate of 10 percent has been used to determine the present value of future cash flows. Changes in the economic conditions could significantly change the estimated recoverable amount.

Employee Benefit Plans and Post-Employment Benefits

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which, by their nature, are subject to measurement uncertainty.

Compensation Plans

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under the Cenovus compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

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. 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.

Contingencies

Contingencies, by their nature, are subject to measurement uncertainty as the financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies involves a significant amount of judgment including assessing whether a present obligation exists and providing a reliable estimate of the amount of cash outflow required to settle the obligation. The uncertainty involved with the timing and amount at which a contingency will be settled may have a material impact on the Consolidated Financial Statements of future periods to the extent that the amount provided for differs from the actual outcome.

Financial Instruments

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Company may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

5. FINANCE COSTS

For the years ended December 31,	2011	2010
Interest Expense – Short-Term Borrowings and Long-Term Debt	213	227
Interest Expense – Partnership Contribution Payable	138	165
Unwinding of Discount on Decommissioning Liabilities	75	75
Other	21	31
	447	498

6. INTEREST INCOME

For the years ended December 31,	2011	2010
Interest Income – Partnership Contribution Receivable	120	144
Other	4	-
	124	144

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7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2011	2010
Unrealized Foreign Exchange (Gain) Loss on translation of:		
U.S. dollar debt issued from Canada	78	(182)
U.S. dollar Partnership Contribution Receivable issued from Canada	(107)	91
Other	(13)	22
Unrealized Foreign Exchange (Gain) Loss	(42)	(69)
Realized Foreign Exchange (Gain) Loss	68	18
	26	(51)

8. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31,	2011	2010
Current Tax		
Canada	150	82
United States	4	-
Total Current Tax	154	82
Deferred Tax	575	141
	729	223

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

For the years ended December 31,	2011	2010
Earnings Before Income Tax	2,207	1,304
Canadian Statutory Rate	26.7%	28.2%
Expected Income Tax	589	368
Effect of Taxes Resulting from:		
Foreign tax rate differential	78	(22)
Non-deductible stock-based compensation	18	34
Multi-jurisdictional financing	(50)	(93)
Foreign exchange gains (losses) not included in net earnings	(9)	28
Non-taxable capital (gains) losses	(9)	(13)
Capital losses	26	(107)

Adjustments arising from prior year tax filings	**31**	26
Other	**55**	2
	729	223
Effective Tax Rate	**33.0%**	17.1%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

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

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Deferred Income Tax Liabilities			
Deferred tax liabilities (assets) to be settled (recovered) within 12 months	**117**	57	(68)
Deferred tax liabilities to be settled after more than 12 months	**1,984**	1,515	1,552
	2,101	1,572	1,484
Deferred Income Tax Assets			
Deferred tax assets to be recovered within 12 months	**-**	(3)	-
Deferred tax assets to be recovered after more than 12 months	**-**	(52)	(3)
	-	(55)	(3)
Net Deferred Income Tax Liability	**2,101**	1,517	1,481

For the purposes of the above table, deferred income tax assets are shown net of offsetting deferred income tax liabilities where these occur in the same entity and jurisdiction. The deferred income tax liabilities and assets to be settled (recovered) 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 other comprehensive income	(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 other comprehensive income	18	-	-	-	2	20
As at December 31, 2011	**2,394**	**163**	**112**	**71**	**132**	**2,872**

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 other comprehensive income	8	-	-	8
As at December 31, 2010	(281)	(45)	(170)	(496)
Charged/(credited) to earnings	(270)	29	(21)	(262)
Charged/(credited) to other comprehensive income	(13)	-	-	(13)
As at December 31, 2011	**(564)**	**(16)**	**(191)**	**(771)**

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 other comprehensive income	(103)
Net Deferred Income Tax Liabilities as at December 31, 2010	1,517
Charged/(credited) to earnings	577
Charged/(credited) to other comprehensive income	7
Net Deferred Income Tax Liabilities as at December 31, 2011	**2,101**

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The allocation of deferred income tax expense is comprised of:

As at	December 31, 2011	December 31, 2010
Credited/(charged) to net deferred income tax liabilities	577	137
Credited/(charged) to liabilities related to assets held for sale	(2)	4
Deferred Income Tax Expense	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, 2011	December 31, 2010	January 1, 2010
Canada	4,471	4,239	3,754
United States	2,740	3,082	2,637
	7,211	7,321	6,391

At December 31, 2011, the above tax pools included $78 million (December 31, 2010 – $236 million, January 1, 2010 – $491 million) of Canadian non-capital losses and $1,479 million (December 31, 2010 – $607 million, January 1, 2010 – $232 million) of U.S. net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2011 tax pools are Canadian net capital losses totaling $759 million (December 31, 2010 – $983 million, January 1, 2010 – $51 million) which are available for carry forward to reduce future capital gains. Of these losses, $286 million are unrecognized as a deferred income tax asset at December 31, 2011 (December 31, 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 ($ millions, except earnings per share)	December 31, 2011			December 31, 2010		
	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	1,478	754.0	$1.96	1,081	751.9	$1.44
Dilutive effect of Cenovus TSARs	-	3.7		-	2.1	
Dilutive effect of NSRs	-	-		-	-	
Net earnings per share – diluted	1,478	757.7	$1.95	1,081	754.0	$1.43

B) Dividends per Share

The dividends paid in 2011 and 2010 were $603 million ($0.80 per share) and $601 million ($0.80 per share) respectively. The Cenovus Board of Directors declared a first quarter 2012 dividend of $0.22 per share, payable on March 30, 2012, to common shareholders of record as of March 15, 2012.

10. CASH AND CASH EQUIVALENTS

As at	December 31, 2011	December 31, 2010	January 1, 2010
Cash	232	160	76
Short-Term Investments	263	140	79
	495	300	155

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11. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	December 31, 2011	December 31, 2010	January 1, 2010
Accruals	801	606	409
Trade	251	242	395
Joint Operations with Partners	30	32	32
Prepaids and Deposits	34	24	20
Interest	28	32	38
Other	261	123	88
	1,405	1,059	982

12. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In connection with the Arrangement with Encana (Note 1), Cenovus acquired Encana's assets which are jointly controlled with ConocoPhillips. On January 2, 2007, Encana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consisted of an upstream entity and a refining entity. The upstream entity contribution included assets from Encana, primarily the Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable (Partnership Contribution Receivable) contributed from ConocoPhillips of an equal amount. For the refining entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Encana contributed a note payable (Partnership Contribution Payable) of US$7.5 billion.

These entities are accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments (Note 29).

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 payments to date.

Mandatory Receipts – Partnership Contribution Receivable

	2012	2013	2014	2015	2016	Thereafter	**Total**
US$	366	386	407	429	452	117	**2,157**
C$ equivalent	372	393	414	436	460	119	**2,194**

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

	2012	2013	2014	2015	2016	Thereafter	**Total**
US$	366	388	412	437	464	121	**2,188**
C$ equivalent	372	395	419	445	472	122	**2,225**

In addition to the Partnership Contribution Receivable and Payable, Other Assets and Other Liabilities include equal amounts for interest bearing partner loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements. At December 31, 2011 these amounts were $nil (December 31, 2010 – $274 million, January 1, 2010 – $183 million) (Notes 18 and 23).

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13. INVENTORIES

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Product			
Refining and Marketing	**1,079**	779	772
Oil Sands	**186**	80	84
Conventional	**1**	-	-
Parts and Supplies	**25**	21	19
	1,291	880	875

The total amount of inventories recognized as an expense during the year was $7,189 million (2010 – $5,997 million).

14. ASSETS AND LIABILITIES HELD FOR SALE

Assets and liabilities classified as held for sale consisted of the following:

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Assets Held for Sale			
Property, plant and equipment	**116**	65	-
Liabilities Related to Assets Held for Sale			
Decommissioning liabilities	**54**	5	-
Deferred income taxes	-	2	-
	54	7	-

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, resulting in an impairment loss of approximately $2 million which has been recorded as additional depreciation, depletion and amortization in the Consolidated Statement of Earnings and Comprehensive Income. These assets and the related liabilities are reported in the

Conventional segment.

In January 2012, the Company completed the sale of the natural gas assets to an unrelated third party for net proceeds of $63 million.

Marine Terminal Facilities

On November 1, 2010, under the terms of an agreement with a non-related Canadian company, Cenovus acquired certain marine terminal facilities in Kitimat, British Columbia for cash consideration of $38 million. The net assets were recorded at estimated fair value less costs to sell and classified as held for sale. These assets and liabilities were reported in the Refining and Marketing segment. Cenovus recognized a bargain purchase gain of $12 million, resulting from the excess fair value of the net assets acquired over the cash consideration paid. The gain was recorded in other income.

In October 2011, the Company completed the sale of the marine terminal facilities and recorded an after-tax gain on sale of $89 million.

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15. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at January 1, 2010	580
Additions	350
Transfers to property, plant and equipment (Note 16)	(144)
Divestitures	(81)
Change in decommissioning liabilities	8
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**

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, 2011 include $15 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2010 – $11 million).

For the year ended December 31, 2011, $356 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 in question (year ended December 31, 2010 – $144 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statement of Earnings and Comprehensive Income. There were no impairments of E&E assets in 2011 and 2010.

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16. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at January 1, 2010	20,836	134	2,419	427	23,816
Additions	1,061	19	651	136	1,867
Transfers from E&E assets (Note 15)	144	-	-	-	144
Transfers and reclassifications	-	-	-	(92)	(92)
Change in decommissioning liabilities	237	-	22	-	259
Exchange rate movements	(2)	-	(142)	-	(144)
Divestitures	(556)	-	-	(21)	(577)
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**
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT					
As at January 1, 2010	11,342	113	15	297	11,767
Depreciation and depletion expense	1,163	11	72	42	1,288
Transfers and reclassifications	-	-	-	(28)	(28)
Impairment losses	-	-	14	-	14
Exchange rate movements	(1)	-	(4)	-	(5)
Divestitures	(383)	-	-	(7)	(390)
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	1,108	15	85	40	1,248
Impairment losses	2	-	45	-	47
Transfers and reclassifications	(211)	-	(5)	-	(216)
Exchange rate movements	1	-	3	-	4
As at December 31, 2011	**13,021**	**139**	**225**	**344**	**13,729**
CARRYING VALUE					
As at January 1, 2010	9,494	21	2,404	130	12,049
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**

1. Includes office furniture, fixtures, leasehold improvements, information technology, aircraft and marine terminal facilities.

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of $125 million (2010 – $87 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 2011 (2010 – $nil).

Property, plant and equipment include the following amounts in respect of assets under construction which are not subject to depreciation until put into use:

As at	December 31, 2011	December 31, 2010	January 1, 2010
Development and production	**52**	42	64
Refining equipment	**125**	1,673	1,366
Other	**112**	45	4
	289	1,760	1,434

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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 Statement of Earnings and Comprehensive Income.

Depreciation, depletion and amortization expense includes impairment losses as follows:

As at	December 31, 2011	December 31, 2010	January 1, 2010
Development and Production	**2**	-	-
Refining Equipment	**45**	14	-
	47	14	-

The impairment losses during the year 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 have been reclassified as held for sale (Note 14). The natural gas assets reside in the Conventional segment. The 2010 impairment loss was related to a processing unit at the Borger Refinery which was determined to be a redundant asset.

17. DIVESTITURES

In 2011, the Company disposed of non-core oil and 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 oil and gas properties and corporate assets.

18. OTHER ASSETS

As at	December 31, 2011	December 31, 2010	January 1, 2010
Partner Loans	**-**	274	183
Long-term Receivables	**18**	7	7

Prepaids	8	-	-
Other	18	-	2
	44	281	192

19. GOODWILL

As at	December 31, 2011	December 31, 2010
Carrying Value, Beginning of Year	1,132	1,146
Divestitures	-	(14)
Impairment	-	-
Carrying Value, End of Year	1,132	1,132
Cost	1,132	1,132
Accumulated Impairment	-	-
Carrying Value, End of Year	1,132	1,132

There were no additions to goodwill during 2011 and 2010.

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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, 2011	December 31, 2010	January 1, 2010
Suffield	393	393	393
Palliser	-	-	14
Foster Creek	242	242	242
Northern Alberta	497	497	497
	1,132	1,132	1,146

There was no impairment of goodwill in 2011 and 2010.

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	December 31, 2011	December 31, 2010	January 1, 2010
Accruals	1,193	852	545
Trade	789	471	509
Employee Long-Term Incentives	209	267	217
Interest	72	74	104
Other	316	179	230
	2,579	1,843	1,605

21. LONG-TERM DEBT

As at	Note	December 31, 2011	December 31, 2010	January 1, 2010
Canadian Dollar Denominated Debt				
Revolving term debt [1]	A	-	-	32
U.S. Dollar Denominated Debt				
Revolving term debt [1]	A	-	-	26
Unsecured notes (US$ 3,500)	B	3,559	3,481	3,663
		3,559	3,481	3,689
Total Debt Principal		3,559	3,481	3,721
Debt Discounts and Transaction Costs	C	(32)	(49)	(65)
Current Portion of Long-Term Debt	D	-	-	-
		3,527	3,432	3,656

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, 2011 was 5.5 percent (2010 – 5.8 percent).

A) Revolving Term Debt

At December 31, 2011, Cenovus had in place a committed credit facility in the amount of $3,000 million or its equivalent amount in U.S. dollars. The committed credit facility matures on November 30, 2015 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, 2011, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2010 – $nil, January 1, 2010 – $58 million).

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B) Unsecured Notes

Unsecured notes are comprised of the following senior unsecured notes:

	US$ Principal Amount	December 31, 2011	December 31, 2010	January 1, 2010
4.50% due September 15, 2014	800	814	796	837
5.70% due October 15, 2019	1,300	1,322	1,293	1,361
6.75% due November 15, 2039	1,400	1,423	1,392	1,465
	3,500	3,559	3,481	3,663

Cenovus has in place a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1,500 million. 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, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2011, no medium term notes have been issued under this Canadian prospectus. The shelf prospectus expires in July 2012.

Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$1,500 million. 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, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2011, no notes have been issued under this U.S. prospectus. The shelf prospectus expires in August 2012.

At December 31, 2011, the Company is in compliance with all of the terms of its debt agreements.

C) 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 being amortized using the effective interest rate method. Transaction costs associated with the revolving term debt have been recorded as a prepayment and are being amortized over the remaining term of the committed credit facility. During 2011, additional transaction costs of $3 million were recorded (2010 – $nil).

D) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	Total C$ Equivalent
2012	-	-	-
2013	-	-	-
2014	800	-	814
2015	-	-	-
2016	-	-	-
Thereafter	2,700	-	2,745
	3,500	-	3,559

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22. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the future costs associated with the retirement of upstream oil and gas assets and refining facilities. The aggregate carrying amount of the obligation is as follows:

As at	December 31, 2011	December 31, 2010
Decommissioning Liabilities, Beginning of Year	1,399	1,185
Liabilities incurred	49	44
Liabilities settled	(56)	(32)
Liabilities divested	-	(90)
Transfers and reclassifications	(55)	(5)
Change in estimated future cash flows	146	51
Change in discount rate	218	173
Unwinding of discount on decommissioning liabilities	75	75

Foreign currency translation	1	(2)
Decommissioning Liabilities, End of Year	1,777	1,399

The undiscounted amount of estimated cash flows required to settle the obligation is $6,541 million (December 31, 2010 – $6,093 million, January 1, 2010 – $5,683 million), which has been discounted using a credit-adjusted risk free rate of 4.8 percent (December 31, 2010 – 5.4 percent, January 1, 2010 – 6.0 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.

Sensitivities

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

	2011		2010	
As at	Credit-adjusted risk-free rate	Inflation rate	Credit-adjusted risk-free rate	Inflation rate
One percent increase	(367)	504	(287)	398
One percent decrease	494	(379)	388	(278)

23. OTHER LIABILITIES

As at	December 31, 2011	December 31, 2010	January 1, 2010
Partner Loans	-	274	183
Deferred Revenue	35	37	40
Employee Long-Term Incentives	55	18	-
Pension and Other Post-Employment Benefits	16	13	19
Other	22	4	4
	128	346	246

24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension plan that includes defined contribution and defined benefit components, and other post-employment benefit plans ("OPEB"). Most of the employees participate in the defined contribution pension; the defined benefit pension component is closed to new entrants.

The Company files an actuarial valuation of its pension plans with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2010 and the next required actuarial valuation will be as at December 31, 2013.

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Information related to defined benefit pension and OPEB plans, based on actuarial estimations is as follows:

	Pension Benefits		
As at	December 31, 2011	December 31, 2010	January 1, 2010
Accrued Benefit Obligation, End of Year	84	68	56
Fair Value of Plan Assets, End of Year	61	59	54
Funded Status–Plan Assets (less) than Benefit Obligation	(23)	(9)	(2)
Amounts Not Recognized:			
Unamortized net actuarial (gain) loss	22	8	-
Unamortized past service cost	-	-	-
Accrued Benefit Asset (Liability)	(1)	(1)	(2)

	OPEB		
As at	December 31, 2011	December 31, 2010	January 1, 2010
Accrued Benefit Obligation, End of Year	19	14	11
Fair Value of Plan Assets, End of Year	-	-	-
Funded Status–Plan Assets (less) than Benefit Obligation	(19)	(14)	(11)
Amounts Not Recognized:			
Unamortized net actuarial (gain) loss	4	2	-
Unamortized past service cost	-	-	-
Accrued Benefit Asset (Liability)	(15)	(12)	(11)

Pension and other post-employment benefit costs recognized are as follows:

	Pension Benefits		OPEB	
For the years ended December 31,	2011	2010	2011	2010
Current Service Cost	3	3	2	1
Interest Cost	4	3	1	1
Expected Return on Plan Assets	(4)	(3)	-	-
Actuarial Gains (Losses)	1	-	-	-

Past Service Cost	-	-	-	-
Effect of Curtailment/Settlement	-	-	-	-
Plan Cost	4	3	3	2
Defined Contribution Plans Cost	22	18	-	-
Net Benefit Plan Cost	26	21	3	2

The weighted average actuarial assumptions used to determine benefit obligations are as follows:

	Pension Benefits			OPEB		
As at	December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	January 1, 2010
Discount Rate	4.25%	5.25%	6.00%	4.25%	5.25%	6.00%
Rate of Compensation Increase	3.99%	4.05%	4.05%	5.77%	5.65%	5.77%

The expected future benefits payments for the year ended December 31, 2012 is $2 million for the defined benefit plan and $nil for the OPEB.

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25. SHARE CAPITAL

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.

Issued and Outstanding

	2011		2010	
As at December 31,	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	752,675	3,716	751,309	3,681
Common Shares Issued under Stock Option Plans	1,824	64	1,366	35
Outstanding, End of Year	754,499	3,780	752,675	3,716

There were no Preferred Shares outstanding as at December 31, 2011 (2010 – nil).

At December 31, 2011, there were 30 million (2010 – 26 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.

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 January 1, 2010 and December 31, 2010	4,083	-	4,083
Stock-based compensation expense	-	24	24
As at December 31, 2011	4,083	24	4,107

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.

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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, 2011	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	1.35	31.97	18.89	10,411
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	5	1.38	28.96	33.83	9,686
TSARs	Prior to February 17, 2010	5	1.45	28.95	33.83	9,395
TSARs	On or After February 17, 2010	7	5.20	26.72	33.83	5,526
NSRs	On or After February 24, 2011	7	6.24	36.95	33.83	5,809

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, 2011 was $8.27 before considering forfeitures. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2011
Risk Free Interest Rate	2.46%
Expected Dividend Yield	2.16%
Expected Volatility [1]	28.81%
Expected Life (Years)	4.55

1. Expected volatility has been based on historical volatility of the Company's publicly traded shares.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables summarize the information related to the NSRs as at December 31, 2011:

As at December 31, 2011 (thousands of units)	NSRs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	-	-
Granted	5,931	36.96
Exercised as options for common shares	-	-
Forfeited	(122)	37.50
Outstanding, End of Year	5,809	36.95
Exercisable, End of Year	1	37.54

	Outstanding NSRs (thousands of units)		
Range of Exercise Price ($)	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)

30.00 to 39.99	5,809	6.24	36.95
	5,809	6.24	36.95

	Exercisable NSRs (thousands of units)	
Range of Exercise Price ($)	NSRs	Weighted Average Exercise Price ($)
30.00 to 39.99	1	37.54
	1	37.54

TSARs Held by Cenovus Employees

The Company has recorded a liability of $90 million at December 31, 2011 (December 31, 2010 – $87 million, January 1, 2010 – $43 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:

	2011
Risk Free Interest Rate	1.10%
Expected Dividend Yield	2.36%
Expected Volatility [1]	31.95%
Cenovus's Common Share Price	$33.83

1. Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2011 was $43 million (December 31, 2010 – $42 million).

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The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,044	7,073	19,117	27.75
Granted	138	-	138	33.40
Exercised for cash payment	(1,274)	(641)	(1,915)	26.31
Exercised as options for common shares	(1,202)	(564)	(1,766)	26.38
Forfeited	(315)	(338)	(653)	28.37
Outstanding, End of Year	9,391	5,530	14,921	28.12
Exercisable, End of Year	4,618	4,256	8,874	29.15

The weighted average market price of Cenovus's common shares at the date of exercise during the year ended December 31, 2011 was $35.71.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	7,617	3,578	11,195	3.32	26.43
30.00 to 39.99	1,711	1,952	3,663	1.40	33.03
40.00 to 49.99	63	-	63	1.45	43.30
	9,391	5,530	14,921	2.84	28.12

	Exercisable TSARs (thousands of units)			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	3,029	2,304	5,333	26.45
30.00 to 39.99	1,526	1,952	3,478	33.04
40.00 to 49.99	63	-	63	43.30
	4,618	4,256	8,874	29.15

The market price of Cenovus common shares at December 31, 2011 was $33.83.

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, 2011 (December 31, 2010 – $24 million, January 1, 2010 – $70 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:

	2011
Risk Free Interest Rate	0.99%
Expected Dividend Yield	4.31%
Expected Volatility [1]	28.04%
Encana's Common Share Price	$18.89

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, 2011 was $nil (December 31, 2010 – $6 million).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	6,429	7,098	13,527	31.17
Exercised for cash payment	(1,824)	(451)	(2,275)	26.97
Exercised as options for Encana common shares	(16)	-	(16)	25.71
Forfeited	(308)	(517)	(825)	32.72
Outstanding, End of Year	4,281	6,130	10,411	31.97
Exercisable, End of Year	3,605	4,856	8,461	32.64

The weighted average market price of Encana's common shares at the date of exercise during the year ended December 31, 2011 was $31.95.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	2,437	4,014	6,451	1.48	29.15
30.00 to 39.99	1,711	2,116	3,827	1.12	36.26
40.00 to 49.99	131	-	131	1.48	44.86
50.00 to 59.99	2	-	2	1.39	50.39
	4,281	6,130	10,411	1.35	31.97

	Exercisable TSARs (thousands of units)			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	1,778	2,740	4,518	29.20
30.00 to 39.99	1,694	2,116	3,810	36.28
40.00 to 49.99	131	-	131	44.86
50.00 to 59.99	2	-	2	50.39
	3,605	4,856	8,461	32.64

The market price of Encana common shares at December 31, 2011 was $18.89.

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Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's 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.

The Company has recorded a liability of $83 million at December 31, 2011 (December 31, 2010 – $123 million, January 1, 2010 – $84 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:

	2011

Risk Free Interest Rate	0.99%
Expected Dividend Yield	2.36%
Expected Volatility [1]	31.95%
Cenovus's Common Share Price	$33.83

1. Expected volatility has been based on historical volatility of the Company's publicly traded shares.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at December 31, 2011 was $32 million (December 31, 2010 – $60 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2011:

As at December 31, 2011 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,214	8,940	17,154	28.16
Exercised for cash payment	(4,082)	(2,758)	(6,840)	27.00
Exercised as options for common shares	(55)	(3)	(58)	23.29
Forfeited	(142)	(428)	(570)	29.14
Outstanding, End of Year	3,935	5,751	9,686	28.96
Exercisable, End of Year	3,203	4,319	7,522	29.73

The weighted average market price of Cenovus's common shares at the date of exercise during the year ended December 31, 2011 was $35.80.

	Outstanding TSARs (thousands of units)				
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	2,197	3,807	6,004	1.55	26.41
30.00 to 39.99	1,671	1,944	3,615	1.11	32.95
40.00 to 49.99	67	-	67	1.44	42.88
	3,935	5,751	9,686	1.38	28.96

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	Exercisable TSARs (thousands of units)			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 29.99	1,465	2,375	3,840	26.48
30.00 to 39.99	1,671	1,944	3,615	32.95
40.00 to 49.99	67	-	67	42.88
	3,203	4,319	7,522	29.73

The market price of Cenovus common shares at December 31, 2011 was $33.83.

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. 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, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $55 million at December 31, 2011 (December 31, 2010 – $18 million, January 1, 2010 – $nil) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2011. The intrinsic value of vested PSUs was $nil at December 31, 2011 and 2010 as PSUs are paid out upon vesting.

The following table summarizes the information related to the PSUs held by Cenovus employees as at December 31, 2011:

(thousands of units)	PSUs
Outstanding, Beginning of Year	1,252
Granted	1,409
Cancelled	(98)
Units in Lieu of Dividends	60
Outstanding, End of Year	2,623

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 $35 million at December 31, 2011 (December 31, 2010 – $31 million, January 1, 2010 – $20 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2011. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

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The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2011:

(thousands of units)	DSUs
Outstanding, Beginning of Year	940
Granted to Directors	65
Granted from Annual Bonus Awards	17
Units in Lieu of Dividends	23
Exercised	(3)
Outstanding, End of Year	1,042

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,	2011	2010
NSRs	16	-
TSARs held by Cenovus employees	24	45
Encana Replacement TSARs held by Cenovus employees	(8)	(20)
PSUs	27	13
DSUs	4	9
Total stock-based compensation expense (recovery)	63	47

27. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2011	2010
Salaries, Bonuses and Other Short-Term Employee Benefits	399	348
Defined Contribution Pension Plan	13	11
Defined Benefit Pension Plan and OPEB	4	(1)
Stock-Based Compensation (Note 26)	63	47
	479	405

28. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), the 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,	2011	2010
Salaries, Director Fees and Short-Term Benefits	25	22
Post-Employment Benefits	3	2
Other Long-Term Benefits	-	-
Stock-Based Compensation	35	37
Total	63	61

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs associated with stock options, NSRs, TSARs, PSUs and DSUs recognized during the year.

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29. INTEREST IN JOINT OPERATIONS

Cenovus has a 50 percent interest in FCCL Partnership, a jointly controlled entity which is involved in the development and production of crude oil. In addition, through its interest in the general partner and a limited partner, Cenovus has a 50 percent interest in WRB Refining LP, a jointly controlled entity, which owns two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products.

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Summarized financial statement information for these jointly controlled entities is as follows:

Consolidated Statements of Earnings For the years ended December 31,	FCCL Partnership [1]		WRB Refining LP [1]	
	2011	2010	**2011**	2010
Revenues	**2,364**	1,829	**8,672**	6,624
Expenses				
Purchased product	**-**	-	**7,223**	6,095
Operating, transportation and blending and realized gain/loss on risk management	**1,397**	1,074	**473**	462
Operating Cash Flow	**967**	755	**976**	67
Depreciation, depletion and amortization	**205**	210	**130**	86
Other expenses (income)	**(136)**	20	**(4)**	13
Net Earnings (Loss)	**898**	525	**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.

Consolidated Balance Sheets as at	FCCL Partnership			WRB Refining LP		
	December 31, 2011	December 31, 2010	January 1, 2010	**December 31, 2011**	December 31, 2010	January 1, 2010
Current Assets	**937**	703	800	**1,402**	951	812
Long-term Assets	**6,864**	6,419	6,374	**3,188**	2,840	2,391
Current Liabilities	**317**	229	147	**759**	559	515
Long-term Liabilities	**83**	40	29	**73**	327	407

Capital commitments through jointly controlled entities are as follows:

2011	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Capital Commitments	179	58	11	2	3	-	**253**

2010	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Capital Commitments	147	10	3	3	-	-	**163**

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 includes the Company's short-term borrowings plus long-term debt, including the current portion. 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 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 ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. 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 continues to target a Debt to Capitalization ratio of between 30 and 40 percent.

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As at	**December 31, 2011**	December 31, 2010	January 1, 2010
Short-Term Borrowings	-	-	-
Long-Term Debt	**3,527**	3,432	3,656
Debt	**3,527**	3,432	3,656
Shareholders' Equity	**9,406**	8,395	7,809
Total Capitalization	**12,933**	11,827	11,465
Debt to Capitalization	**27%**	29%	32%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at	December 31, 2011	December 31, 2010
Debt	3,527	3,432
Net Earnings	1,478	1,081
Add (deduct):		
Finance costs	447	498
Interest income	(124)	(144)
Income tax expense	729	223
Depreciation, depletion and amortization	1,295	1,302
Exploration expense	-	-
Unrealized (gain) loss on risk management	(180)	(46)
Foreign exchange (gain) loss, net	26	(51)
(Gain) loss on divestiture of assets	(107)	(116)
Other (income) loss, net	4	(13)
Adjusted EBITDA	3,568	2,734
Debt to Adjusted EBITDA	1.0x	1.3x

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 the 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.

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, Cenovus changed its definition of Adjusted EBITDA to exclude unrealized gains and losses on risk management activities. The Adjusted EBITDA and the ratio of Debt to Adjusted EBITDA for prior periods have been re-presented in a consistent manner. As noted above, Cenovus's capital structure objectives and targets remain unchanged from previous periods. At December 31, 2011, 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, long-term debt and obligations for stock-based compensation carried at fair value. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

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A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities 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.

	December 31, 2011		December 31, 2010		January 1, 2010	
As at	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
FINANCIAL ASSETS						
Held-For-Trading:						
Risk management assets	284	284	206	206	61	61
Loans and Receivables:						
Cash and cash equivalents	495	495	300	300	155	155
Accounts receivable and accrued liabilities	1,405	1,405	1,059	1,059	982	982
Partnership contribution receivable	2,194	2,194	2,491	2,491	2,966	2,966
Other	29	29	-	-	-	-
FINANCIAL LIABILITIES						
Held-For-Trading:						
Risk management liabilities	68	68	173	173	74	74
Financial Liabilities Measured at Amortized Cost:						
Accounts payable and accrued liabilities	2,579	2,579	1,843	1,843	1,605	1,605
Short-term borrowings	-	-	-	-	-	-
Long-term debt	3,527	4,316	3,432	3,940	3,656	3,964
Partnership contribution payable	2,225	2,225	2,519	2,519	2,990	2,990
Other	17	17	-	-	-	-

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement, the 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, 2011	December 31, 2010	January 1, 2010
Risk Management Assets			
Current asset	232	163	60
Long-term asset	52	43	1
	284	206	61
Risk Management Liabilities			
Current liability	54	163	70
Long-term liability	14	10	4
	68	173	74
Net Risk Management Asset (Liability) [1]	216	33	(13)

1. Of the $216 million net risk management asset balance at December 31, 2011, a liability of $3 million relates to the contract with Encana (2010 – net asset of $41 million).

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Summary of Unrealized Risk Management Positions

	December 31, 2011			December 31, 2010			January 1, 2010		
	Risk Management			Risk Management			Risk Management		
As at	Asset	Liability	Net	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices									
Crude Oil	22	65	(43)	4	159	(155)	8	66	(58)
Natural Gas	247	3	244	202	-	202	53	-	53
Power	15	-	15	-	14	(14)	-	8	(8)
Total Fair Value	284	68	216	206	173	33	61	74	(13)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	December 31, 2011	December 31, 2010	January 1, 2010
Prices actively quoted	226	40	6
Prices sourced from observable data or market corroboration	(10)	(7)	(19)
Total Fair Value	216	33	(13)

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, 2011

As at December 31, 2011	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,800 bbls/d	2012	US$98.72/bbl	(1)
WTI NYMEX Fixed Price	24,500 bbls/d	2012	$99.47/bbl	(12)
Other Fixed Price Contracts [1]		2012-2013		(22)
Other Financial Positions [2]				(8)
Crude Oil Fair Value Position				(43)
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	131
AECO Fixed Price [1]	127 MMcf/d	2012	$4.50/Mcf	73
NYMEX Fixed Price	166 MMcf/d	2013	US$4.64/Mcf	43
Other Fixed Price Contracts [1]		2012-2013		(3)
Natural Gas Fair Value Position				244
Power Purchase Contracts				
Power Fair Value Position				15

1. Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada, various sales points and quality differentials.
2. Other financial positions are part of ongoing operations to market the Company's production.

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

For the years ended December 31,	2011	2010
REALIZED GAIN (LOSS) [1]		
Crude Oil	(135)	(17)
Natural Gas	210	289
Refining	(14)	10
Power	7	(4)
	68	278
UNREALIZED GAIN (LOSS) [2]		
Crude Oil	106	(92)
Natural Gas	38	152
Refining	7	(8)
Power	29	(6)
	180	46
Gain (Loss) on Risk Management	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,

	2011		2010
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	33		
Change in fair value of contracts in place at beginning of year and contracts entered into during the year	248	248	324
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	3	-	-
Fair value of contracts realized during the year	(68)	(68)	(278)
Fair Value of Contracts, End of Year	216	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. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

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 natural gas hedges	(160)	160
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	2	(2)
Power commodity price	± $25 per MWHr applied to power hedge	19	(19)

Risk Management Positions in Place as at December 31, 2010

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$10 per bbl applied to WTI hedges	(251)	251
Crude oil differential price	± US$5 per bbl applied to differential hedges tied to production	7	(7)
Natural gas commodity price	± $1 per mcf applied to NYMEX and AECO natural gas hedges	(218)	218
Natural gas basis price	± $0.10 per mcf natural gas basis hedges	2	(2)
Power commodity price	± $25 per MWHr applied to power hedge	38	(38)

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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. To help protect against widening crude oil price differentials, Cenovus has entered into a limited number of swaps and futures to manage the price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX and AECO prices. 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 or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2011, over 92 percent (2010 – 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2011, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (2010 – two counterparties) 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 current concentration 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, 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, 2011, Cenovus's committed credit facility was fully available. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1,500 million and a U.S. debt shelf prospectus for US$1,500 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

Undiscounted cash outflows relating to financial liabilities are outlined in the table below:

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.

2010	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	1,843	-	-	-	1,843
Risk Management Liabilities	163	10	-	-	173
Long-Term Debt [1]	203	407	1,167	5,236	7,013
Partnership Contribution Payable [1]	486	972	972	609	3,039
Partner Loans Payable	-	274	-	-	274

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, 2011, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,500 million at December 31, 2010) and US$2,157 million related to the U.S. dollar Partnership Contribution Receivable (US$2,505 million at December 31, 2010). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $13 million change in foreign exchange (gain) loss at December 31, 2011 (2010 – $10 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the 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, 2011, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2010 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

32. SUPPLEMENTARY INFORMATION

Supplementary Cash Flow Information

For the years ended December 31,	2011	2010
Interest Paid	357	423
Income Taxes Paid	-	62

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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:

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
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 by the Company on behalf of FCCL Partnership are reflected at Cenovus's 50 percent interest.

2010	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Pipeline Transportation [1]	107	93	167	167	166	953	1,653
Operating Leases (Building Leases)	33	87	88	85	78	1,553	1,924
Product Purchases	23	18	18	18	18	7	102
Capital Commitments [2]	248	94	16	14	11	37	420
Other Long-Term Commitments	4	2	1	1	-	1	9
Total Payments [3]	415	294	290	285	273	2,551	4,108
Product Sales	50	52	54	56	57	63	332

1. Certain transportation commitments included are subject to regulatory approval.
2. Includes those commitments related to jointly controlled entities.
3. Contracts undertaken by the Company on behalf of FCCL Partnership are reflected at Cenovus's 50 percent interest.

At December 31, 2011, there were outstanding letters of credit aggregating $17 million issued as security for performance under certain contracts (2010 – $23 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 related to its oil and gas properties, refining facilities and midstream facilities at the end of their useful lives. Cenovus has recognized a liability of $1,777 million based on current legislation and estimated costs. 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.

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34. FIRST TIME ADOPTION OF IFRS

Transition to IFRS

These Consolidated Financial Statements for the year ended December 31, 2011 represent the Company's first annual consolidated financial statements prepared in accordance with IFRS, which are also generally accepted accounting principles for publicly accountable enterprises in Canada. The Company adopted IFRS in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and has prepared its Consolidated Financial Statements with IFRS applicable for periods beginning on or after January 1, 2010, using significant accounting policies as described in Note 3. For all periods up to and including the year ended December 31, 2010, the Company prepared its Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). As allowed by IFRS 1, the Company has chosen not to include the comparative financial information for the year ended December 31, 2009. This note explains the principal adjustments made by the Company to restate its previous GAAP Consolidated Financial Statements on transition to IFRS.

Exemptions Applied under IFRS 1

On first-time adoption of IFRS, the general principle is that an entity retrospectively restates its results for all standards in force at the first reporting date. However, IFRS 1 provides certain exemptions from the general requirements of IFRS to assist with the transition process. Cenovus has applied the following exemptions in the preparation of its opening Balance Sheet dated January 1, 2010 (the "Transition Date"):

- **Fair Value as Deemed Cost** – The Company has elected to measure its Refining assets at their fair values at the Transition Date and use those fair values as their deemed cost at that date (Note A).
- **Deemed Cost Election for Oil and Gas Assets** – Under previous GAAP, Cenovus accounted for its oil and gas properties in one cost centre using full cost accounting. The Company has elected to measure its oil and gas properties at the Transition Date on the following basis:
  a) exploration and evaluation assets at the amount determined under the Company's previous GAAP; and
  b) the remainder allocated to the underlying property, plant and equipment assets on a pro rata basis using proved reserve values discounted at 10 percent at the Transition Date (Note B).
- **Leases** – Cenovus has elected to assess lease arrangements using the facts and circumstances as of the Transition Date under International Financial Reporting Interpretations Committee Interpretation 4, *"Determining whether an Arrangement contains a Lease"* ("IFRIC 4").
- **Employee Benefits** – The Company has elected not to apply IAS 19, *"Employee Benefits"* retrospectively and as such all cumulative actuarial gains and losses on the Company's defined benefit plans were recognized at the Transition Date (Note F).
- **Business Combinations** – IFRS 3, *"Business Combinations"* has not been applied to business combinations that occurred before the Transition Date.
- **Cumulative Currency Translation Differences** – Cumulative currency translation differences for all foreign operations are deemed to be zero at the Transition Date (Note J).
- **Decommissioning Liabilities** – Cenovus applied the deemed cost election for oil and gas assets under IFRS 1 and as such decommissioning liabilities at the date of transition have been measured in accordance with IAS 37, *"Provisions, Contingent Liabilities and Contingent Assets"* (Note D).
- **Borrowing Costs** – In accordance with IFRS 1, the Company has elected to apply IAS 23, *"Borrowing Costs"* to qualifying assets for which the commencement date for capitalization of borrowing costs occurred on or after the Transition Date. Borrowing costs have not been capitalized on qualifying assets under construction on or before the Transition Date.
- **Estimates** – Hindsight was not used to create or revise estimates and accordingly, the estimates made by the Company under previous GAAP are consistent with their application under IFRS.

Under IFRS 1, the opening Balance Sheet adjustments are recorded directly to retained earnings, or if appropriate, another category of equity. As Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana into two independent energy companies, Encana and Cenovus, all opening Balance Sheet adjustments have been recorded to paid in surplus. The impacts of applying the above noted IFRS 1 exemptions and the accounting policy differences between previous GAAP and IFRS are summarized in the following tables:

Reconciliation of Statement of Earnings and Comprehensive Income
For the year ended December 31, 2010

	Notes	Previous GAAP	Adjustments	IFRS
Revenues				
Gross Sales	K	13,422	(332)	**13,090**
Less: Royalties		449	-	**449**
		12,973	(332)	**12,641**
Expenses				
Purchased product	K	7,549	2	**7,551**
Transportation and blending		1,065	-	**1,065**
Operating	E,F,K	1,302	(16)	**1,286**
Production and mineral taxes		34	-	**34**
(Gain) loss on risk management	K	-	(324)	**(324)**
Depreciation, depletion and amortization	A,B,C	1,310	(8)	**1,302**
Exploration expense	H	-	3	**3**
General and administrative	E,F	251	(5)	**246**
Finance costs	K	-	498	**498**
Interest, net	K	279	(279)	**-**
Interest income	K	-	(144)	**(144)**
Accretion of asset retirement obligation	K	75	(75)	**-**
Foreign exchange (gain) loss, net		(51)	-	**(51)**
(Gain) loss on divestiture of assets	G	9	(125)	**(116)**

Other (income) loss, net		(13)	-	(13)
Earnings Before Income Tax		1,163	141	1,304
Income tax expense	I	170	53	223
Net Earnings		993	88	1,081
Other Comprehensive Income (Loss), Net of Tax				
Foreign currency translation adjustment	J	(13)	84	71
Comprehensive Income (Loss)		980	172	1,152
Net Earnings per Common Share				
Basic	L	1.32	0.12	1.44
Diluted	L	1.32	0.11	1.43

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Reconciliation of the Balance Sheet
As at

		December 31, 2010			January 1, 2010		
	Notes	Previous GAAP	Adjustments	IFRS	Previous GAAP	Adjustments	IFRS
Assets							
Current Assets							
Cash and cash equivalents		300	-	300	155	-	155
Accounts receivable and accrued revenues	E	1,055	4	1,059	978	4	982
Income tax receivable		31	-	31	40	-	40
Current portion of Partnership Contribution Receivable		346	-	346	345	-	345
Inventories		880	-	880	875	-	875
Risk management		163	-	163	60	-	60
Assets held for sale	K	-	65	65	-	-	-
Current Assets		2,775	69	2,844	2,453	4	2,457
Assets Held for Sale	K	65	(65)	-	-	-	-
Exploration and Evaluation Assets	K	-	713	713	-	580	580
Property, Plant and Equipment, net	A,B,D, E,F,G, H,J,K	15,530	(2,903)	12,627	15,214	(3,165)	12,049
Partnership Contribution Receivable		2,145	-	2,145	2,621	-	2,621
Risk Management		43	-	43	1	-	1
Other Assets	C,F,J	391	(110)	281	320	(128)	192
Deferred Income Tax	K	-	55	55	-	3	3
Goodwill	G	1,146	(14)	1,132	1,146	-	1,146
Total Assets		22,095	(2,255)	19,840	21,755	(2,706)	19,049
Liabilities and Shareholders' Equity							
Current Liabilities							
Accounts payable and accrued liabilities	E	1,825	18	1,843	1,574	31	1,605
Income tax payable		154	-	154	-	-	-
Current portion of Partnership Contribution Payable		343	-	343	340	-	340
Risk management		163	-	163	70	-	70
Liabilities related to assets held for sale	K	-	7	7	-	-	-
Current Liabilities		2,485	25	2,510	1,984	31	2,015
Liabilities Related to Assets Held for Sale	K	7	(7)	-	-	-	-
Long-Term Debt		3,432	-	3,432	3,656	-	3,656
Partnership Contribution Payable		2,176	-	2,176	2,650	-	2,650
Risk Management		10	-	10	4	-	4
Decommissioning Liabilities	D,G	1,213	186	1,399	1,147	38	1,185
Other Liabilities	F	346	-	346	239	7	246
Deferred Income Tax	I,J,K	2,404	(832)	1,572	2,467	(983)	1,484
Total Liabilities		12,073	(628)	11,445	12,147	(907)	11,240
Share Capital		3,716	-	3,716	3,681	-	3,681
Paid in Surplus	A,C,D, E,F,I,J	5,896	(1,813)	4,083	5,896	(1,813)	4,083
Accumulated Other Comprehensive Income (Loss)	J	(27)	98	71	(14)	14	-
Retained Earnings		437	88	525	45	-	45
Shareholders' Equity		10,022	(1,627)	8,395	9,608	(1,799)	7,809
Total Liabilities and Shareholders' Equity		22,095	(2,255)	19,840	21,755	(2,706)	19,049

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Reconciliation of the Statement of Cash Flows
For the year ended December 31, 2010

	Notes	Previous GAAP	Adjustments	IFRS
Operating Activities				
Net earnings		993	88	**1,081**
Depreciation, depletion and amortization	A,B,C	1,310	(8)	**1,302**
Deferred income taxes	I	88	53	**141**
Unrealized (gain) loss on risk management		(46)	-	**(46)**
Unrealized foreign exchange (gain) loss		(69)	-	**(69)**
(Gain) loss on divestitures of assets	G	9	(125)	**(116)**
Unwinding of discount on decommissioning liabilities		75	-	**75**
Other		55	(11)	**44**
		2,415	(3)	**2,412**
Net change in other assets and liabilities		(55)	-	**(55)**
Net change in non-cash working capital		234	-	**234**
Cash From Operating Activities		2,594	(3)	**2,591**
Investing Activities				
Capital expenditures – exploration and evaluation assets		-	(350)	**(350)**
Capital expenditures – property, plant and equipment		(2,208)	357	**(1,851)**
Proceeds from divestitures of assets		309	-	**309**
Net change in investments and other		4	-	**4**
Net change in non-cash working capital	E	99	(4)	**95**
Cash From (Used in) Investing Activities		(1,796)	3	**(1,793)**
Net Cash Provided (Used) before Financing Activities		798	-	**798**
Cash From (Used in) Financing Activities		(631)	-	**(631)**
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		(22)	-	**(22)**
Increase (Decrease) in Cash and Cash Equivalents		145	-	**145**
Cash and Cash Equivalents, Beginning of Year		155	-	**155**
Cash and Cash Equivalents, End of Year		300	-	**300**

Notes:

A) Refining Property, Plant and Equipment

At January 1, 2010, Cenovus elected to measure its refining assets at fair value and to use that fair value as its deemed cost on transition to IFRS. The fair value of the refining assets was determined to be US$4,543 million, US$2,272 million net to Cenovus, which resulted in the carrying value of the refining assets exceeding the fair value. Cenovus's carrying value of property, plant and equipment was reduced by C$2,585 million at the Transition Date with a corresponding reduction in paid in surplus.

In December 2010, it was determined that a processing unit at the Borger Refinery was a redundant asset and would not be used in future operations at the refinery. The fair value of the unit was determined to be negligible based on market prices for refining assets of similar age and condition. Accordingly, under previous GAAP, an impairment of $37 million was recorded. Under IFRS, the impairment was only $14 million due to the IFRS 1 election noted above to use the fair value as deemed cost. Therefore DD&A expense under IFRS was reduced by $23 million.

The lower carrying value under IFRS and the impairment adjustment noted above resulted in lower DD&A expense of $126 million for the year ended December 31, 2010.

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B) Oil and Gas Property, Plant and Equipment

Under previous GAAP, costs accumulated within each cost centre for oil and gas properties were depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs on a country-by-country cost centre basis (full cost accounting). Under IFRS, 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 on an area-by-area basis. This resulted in an increase of $135 million in DD&A expense for the year ended December 31, 2010.

C) Impairment of Deferred Asset

Under previous GAAP, other assets included a deferred asset, which represented the disproportionate interest received in 2007 and 2008 (15 percent in 2007 and 35 percent in 2008) that arose from the acquisition of the Borger Refinery in 2007. On transition to IFRS, it was determined that as a result of the reduction in the carrying value of the refineries due to the fair value election, the deferred asset was impaired and therefore was written off. Paid in surplus was decreased by the carrying value of the asset under previous GAAP of $121 million. Under previous GAAP, the deferred asset was being amortized over 10 years. As such, DD&A expense under IFRS decreased by $17 million for the year ended December 31, 2010.

D) Decommissioning Liabilities

As discussed above, the Company elected to apply the exemption to measure decommissioning liabilities at the Transition Date in accordance with IAS 37. As such, the Company re-measured the decommissioning liabilities as at the Transition Date using the period end credit-adjusted risk-free discount rate and recognized an increase of

$38 million to the decommissioning liability.

Consistent with IFRS, decommissioning liabilities under previous GAAP were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition. However, under IFRS, estimated cash flows are discounted using the credit-adjusted risk-free rate that exists at the balance sheet date. As at December 31, 2010, property, plant and equipment and the decommissioning liability increased $154 million under IFRS. There was minimal impact to the unwinding of the discount for the year ended December 31, 2010.

E) Stock-Based Compensation

Under previous GAAP, obligations for payments under Cenovus's stock option plan (with associated tandem stock appreciation rights) were accrued for using the intrinsic method. Under IFRS, these obligations are accrued for using the fair value method. As a result of the re-measurement of the liability as at January 1, 2010 a charge of $27 million was recognized in paid in surplus with an increase to accounts payable and accrued liabilities of $31 million and an increase to accounts receivable and accrued revenue of $4 million. For the year ended December 31, 2010, due to the differences in the measurement basis under IFRS, operating and general and administrative expense decreased $5 million and $4 million, respectively, property, plant and equipment decreased $4 million and accounts payable and accrued liabilities decreased $13 million.

F) Employee Benefits

Cenovus elected under IFRS 1 to recognize all unamortized actuarial gains and losses on the defined benefit pension and other post-employment benefits plans at the Transition Date resulting, in a $7 million increase to other liabilities, a $7 million decrease to other assets and a $14 million charge to paid in surplus. Under previous GAAP, the actuarial losses continued to be amortized and, as such, for the year ended December 31, 2010, both operating and general and administrative expense decreased by $1 million. In addition, due to the recognition of all unamortized actuarial gains and losses at the Transition date, it was necessary to reclassify the pension asset to a pension liability resulting in a reclassification from other assets to other liabilities of $4 million at December 31, 2010.

G) Gains/Losses on Divestiture of Assets

Under previous GAAP, proceeds on the divestiture of oil and gas properties were credited to the full cost pool and no gain or loss was recognized unless the effect of the sale would have changed the DD&A rate by 20 percent or more. Under IFRS, all gains and losses are recognized on oil and gas property divestitures and calculated as the difference between net proceeds and the carrying value of the net assets disposed. Accordingly, a gain of $125 million was recognized for the year ended December 31, 2010 under IFRS. At December 31, 2010 the carrying value of property, plant and equipment increased $133 million and goodwill and decommissioning liabilities were reduced by $14 million and $6 million, respectively.

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H) Pre-Exploration Expense

Under IFRS, costs incurred prior to obtaining the legal right to explore must be expensed whereas under previous GAAP these costs were capitalized in the full cost pool. For the year ended December 31, 2010, $3 million of pre-exploration costs were expensed under IFRS. The accounting policy difference has resulted in a $3 million decrease to property, plant and equipment and a corresponding increase in exploration expense. This adjustment has decreased cash from operating activities by $3 million and increased cash from investing activities by a corresponding amount for the year ended December 31, 2010.

I) Deferred Income Taxes

The increase in paid in surplus of $986 million at the Transition Date related to deferred income taxes reflects the change in temporary differences resulting from the IFRS 1 exemptions applied. For the year ended December 31, 2010 deferred income tax increased by $53 million to reflect the changes in temporary differences resulting from the IFRS adjustments described above and a $9 million adjustment to recognize the deferred tax benefit on an intercompany transfer of oil and gas properties.

J) Currency Translation Adjustments

In accordance with IFRS 1, Cenovus elected to deem all cumulative currency translation differences for all foreign operations to be zero at the Transition Date. All foreign currency translation differences in respect of foreign operations that arose prior to the Transition Date were transferred to paid in surplus.

In addition, AOCI is affected by the revaluation of the adjustments noted above that reside in a foreign operation notably the reduction in the carrying value of the Refining property, plant and equipment, the impairment of the deferred asset and the associated deferred income tax payable. The table below identifies the cumulative balance sheet impact at December 31, 2010 and January 1, 2010:

Increase (Decrease)	December 31, 2010	January 1, 2010
Assets		
Refining property, plant and equipment	125	-
Other assets	5	-
Liabilities and Equity		
Deferred income tax liability	46	-
Accumulated other comprehensive income	98	14
Paid in surplus	(14)	(14)

K) Reclassifications

Exploration and evaluation ("E&E") assets

Under previous GAAP, E&E assets were included in property, plant and equipment, whereas under IFRS E&E assets are separately disclosed. The Company reclassified $580 million and $713 million from property, plant and equipment to E&E assets at January 1, 2010 and December 31, 2010, respectively.

Finance costs and interest income

In addition, under previous GAAP, the unwinding of the discount on decommissioning liabilities was classified as accretion expense in the Consolidated Statements of Earnings and Comprehensive Income. Under IFRS this amount has been reclassified to finance costs.

Under previous GAAP, interest was reported on a net basis. Under IFRS interest expense is included in finance costs and interest income is reported separately.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2011

Gains/losses on risk management

Under previous GAAP, gains and losses from crude oil and natural gas commodity price risk management activities were recorded in gross revenues. Under IFRS, these activities do not meet the definition of revenue and therefore have been reclassified to (gain) loss on risk management in the Consolidated Statements of Earnings and Comprehensive Income. In addition, risk management activities related to power and the refining business have been reclassified to gain (loss) on risk management activities from operating expense and purchased product, respectively.

Assets and liabilities classified as held for sale

Under previous GAAP, assets held for sale and liabilities related to assets held for sale were included as part of non-current assets and liabilities. Under IFRS, non-current assets that meet the definition of held for sale are required to be classified as current.

Deferred income taxes

A net deferred income tax asset has arisen at January 1, 2010 and December 31, 2010 related to the U.S. foreign operations, due to the adjustments noted above. Consistent with previous GAAP, a deferred income tax asset may not be offset against a deferred income tax liability in a different tax jurisdiction. Accordingly, $55 million and $3 million were reclassified to deferred income tax asset at December 31, 2010 and January 1, 2010, respectively.

L) Net Earnings Per Share

Basic earnings per share

Basic earnings per share under IFRS was impacted by the IFRS earnings adjustments discussed above.

Diluted earnings per share

Under previous GAAP, Cenovus's TSARs, which may be cash or equity settled at the option of the holder, had no dilutive effect on diluted earnings per share because cash settlement was assumed. Under IFRS, the more dilutive of cash settlement and share settlement is required to be used in calculating diluted earnings per share. The following table identifies the differences between previous GAAP and IFRS:

For the year ended December 31, 2010 ($ millions, except earnings per share)	Previous GAAP			IFRS		
	Net Earnings	Shares	Earnings per Share	**Net Earnings**	**Shares**	**Earnings per Share**
Net earnings per share – basic	993	751.9	$1.32	**1,081**	**751.9**	**$1.44**
Dilutive effect of exercised Cenovus TSARs	-	0.8		**-**	**0.8**	
Dilutive effect of outstanding Cenovus TSARs	-	-		-	**1.3**	
Net earnings per share – diluted	993	752.7	$1.32	**1,081**	**754.0**	**$1.43**

M) Debt to Capitalization Ratio

The transition to IFRS resulted in changes to the Company's Debt to Capitalization ratio as follows:

	December 31, 2010		January 1, 2010	
	Previous GAAP	**IFRS**	Previous GAAP	**IFRS**
Long-Term Debt	3,432	**3,432**	3,656	**3,656**
Debt	3,432	**3,432**	3,656	**3,656**
Shareholders' Equity	10,022	**8,395**	9,608	**7,809**
Total Capitalization	13,454	**11,827**	13,264	**11,465**
Debt to Capitalization ratio	26%	**29%**	28%	**32%**

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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, 2011, 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, 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 "Management Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2011, 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 "Auditors' Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2011, 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, 2011, 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., 4000, 421-7th Avenue S.W., Calgary, Alberta, Canada T2P 4K9. 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).

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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.

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, 2011, 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, 2011, 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, 2011, 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.

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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.

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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, thereunto duly authorized.

Date: February 22, 2012

CENOVUS ENERGY INC.

By: /s/ Ivor M. Ruste
Name: Ivor M. Ruste
Title: Executive Vice-President & Chief Financial Officer

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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 22, 2012

/s/ 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 22, 2012

/s/ 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, 2011, 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.

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

February 22, 2012

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, 2011, 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.

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

February 22, 2012

Exhibit 99.5

CONSENT OF PRICEWATERHOUSECOOPERS LLP

We hereby consent to (i) the inclusion in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2011; and (ii) the incorporation by reference in Cenovus Energy Inc.'s Registration Statements on Form S-8 (File No. 333-163397), Form F-3 (File No. 333-166419), and Form F-9 (File No. 333-167876) of our audit report dated February 15, 2012, relating to the Cenovus Energy Inc. Consolidated Financial Statements as of December 31, 2011, December 31, 2010 and January 1, 2010, and for each of the years in the two year period ended December 31, 2011 and the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as of December 31, 2011.

/s/ PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
February 22, 2012

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, 2011, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2011, 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, 2011 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-9 (File No. 333-167876), 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 22, 2012

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, 2011, 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, 2011 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-9 (File No. 333-167876), 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 22, 2012