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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, 2010 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:

752,674,701

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, 2010.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2010.

(c) Consolidated Financial Statements of Cenovus Energy Inc. as at December 31, 2010 *(Note 24 to the Consolidated Financial Statements relates to United States Generally Accepted Accounting Principles and Reporting (U.S. GAAP)).*

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CENOVUS ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2010

February 24, 2011

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FORWARD-LOOKING INFORMATION

This Annual Information Form (“AIF”) 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 AIF 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 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 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; 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 a desirable debt to cash flow ratio; our ability to access external sources of debt and equity capital; success of hedging strategies; 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 relationshi p 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 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 re gulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see

"Risk Factors" in this AIF. Readers should also refer to "Risk Management" in our current Management's Discussion and Analysis and to the risk factors described in other documents we file from time to time with securities regulatory authorities, available at www.sedar.com, www.sec.gov and www.cenovus.com.

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CORPORATE STRUCTURE

Cenovus 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 January 1, 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; effective January 1, 2011, received assigned interest from Cenovus Refinery Services LLC.
(3) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL Partnership.
(4) On December 31, 2010, WRB Refining LLC was converted from a limited liability company to a limited partnership, WRB Refining LP.

The above table includes our subsidiaries and partnerships which have total assets that exceed 10 percent of our total consolidated assets, or sales and revenues which exceed 10 percent of our total consolidated sales and revenues. The assets and revenues of our unnamed subsidiaries and partnerships did not exceed 20 percent of our total consolidated assets or total consolidated sales and revenues at and for the year ended December 31, 2010.

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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 operating and reportable segments are as follows:

- **Upstream**, which includes Cenovus's development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
  - **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 oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company and operated by Cenovus.
  - **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.
- **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 or losses recorded on derivative financial instruments 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 operating and reportable segments shown above were changed from those presented in prior periods to better align with our long range business plan.

All prior periods have been restated to reflect this presentation.

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Three Year History

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

2010

- At the end of 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 two or three phases with a production capacity of 130,000 barrels per day of bitumen.
- In the third quarter of 2010, regulatory approval was received for Foster Creek phases F, G and H. Planned production capacity for each expansion phase is 30,000 barrels per day for a total of 90,000 barrels per day of bitumen.
- In the fourth quarter of 2010, 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 of 2009, two new expansion phases at Foster Creek were commissioned. Phases D and E added capacity of 60,000 barrels per day of bitumen, increasing production capacity of Foster Creek to approximately 120,000 barrels per day of bitumen.
- In the second quarter of 2009, a joint regulatory application for Foster Creek phases F, G and H was submitted to the ERCB and Alberta Environment.
- In the fourth quarter of 2009, FCCL sanctioned the next phase, phase D, of expansion at Christina Lake, which is expected to increase production capacity by 40,000 barrels per day of bitumen in 2013.
- In the fourth quarter of 2009, 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 production capacity by 40,000 barrels per day 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.

2008

- In the second quarter of 2008, Christina Lake phase B expansion was commissioned. This phase added 8,000 barrels per day of production capacity, increasing the total production capacity at Christina Lake to approximately 18,000 barrels per day of bitumen.
- In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction of the Coker and Refinery Expansion ("CORE") project. The expansion is expected to more than double heavy crude oil refining capacity to approximately 240,000 barrels per day and increase crude oil refining capacity by 50,000 barrels per day to approximately 356,000 barrels per day.

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NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our assets, including our refining assets at December 31, 2010.



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Overview

One hundred percent of our reserves and production are located in Canada. At December 31, 2010, we had a land base of approximately 7.2 million net acres and proved reserves (our share before royalties) of approximately 1,154 million barrels of bitumen, 169 million barrels of heavy oil, 111 million barrels of light and medium oil and NGLs and 1,390 billion cubic feet of natural gas. The estimated proved reserves life index at December 31, 2010 was approximately 18 years. We also had probable reserves (our share before royalties) of approximately 523 million barrels of bitumen, 97 million barrels of heavy oil, 49 million barrels of light and medium oil and NGLs and 410 billion cubic feet of natural gas at December 31, 2010.

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 oil assets at Pelican Lake, new resource play assets such as 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.

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 operating 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 2010, the capital investment of $867 million in our Oil Sands business was primarily related to the expansion of FCCL's production capacity. FCCL plans to increase production capacity to approximately 218,000 barrels per day of bitumen from the combined facilities at Foster Creek and Christina Lake following the completion of Christina Lake phase C, expected in 2011 and phase D expansion, expected in 2013. In 2010, we received regulatory approval for the next

three phases of expansion at Foster Creek, phases F, G and H. Oil Sands also continued to develop our new resource play assets, including the drilling of stratigraphic test wells. In 2010, capital investment for Pelican Lake was primarily related to capital maintenance and polymer injection investment on producing assets.

Plans for 2011 include significant capital expenditures on our expansion phases at both Foster Creek and Christina Lake, additional capital investment at our Pelican Lake property, as well as an active stratigraphic test well program in order to enhance our understanding of our new resource play assets and move projects toward the submission of regulatory applications.

At December 31, 2010, we held bitumen rights of approximately 1,162,000 gross acres (859,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 582,880 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, 2010.

Landholdings – Oil Sands	Developed		Undeveloped		Total		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Foster Creek	7	4	65	32	72	36	50%
Christina Lake	1	-	24	12	25	12	50%
Pelican Lake	134	133	294	279	428	412	96%
Athabasca	528	448	345	280	873	728	83%
Other	26	12	1,117	852	1,143	864	76%
Total	696	597	1,845	1,455	2,541	2,052	81%

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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)	2010	2009	2010	2009	2010	2009
Foster Creek	51,147	37,725	-	-	51,147	37,725
Christina Lake	7,898	6,698	-	-	7,898	6,698
Pelican Lake	22,966	24,870	-	-	22,966	24,870
Athabasca	-	-	40	50	6,667	8,333
Other	-	3,057	3	3	500	3,557
Total	82,011	72,350	43	53	89,178	81,183

The following table summarizes our interests in producing wells at December 31, 2010. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2010.

Producing Wells – Oil Sands	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Foster Creek	183	91	-	-	183	91
Christina Lake	19	10	-	-	19	10
Pelican Lake	448	448	11	11	459	459
Athabasca	-	-	459	436	459	436
Other	-	-	20	20	20	20
Total	650	549	490	467	1,140	1,016

Foster Creek

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

In the first quarter of 2009, two new expansion phases were completed at Foster Creek adding gross production capacity of approximately 60,000 barrels per day of bitumen and increasing total gross production capacity to approximately 120,000 barrels per day of bitumen.

In the third quarter of 2010, we received regulatory approval for phases F, G and H which are expected to add approximately 90,000 barrels per day of gross bitumen production capacity.

We have successfully piloted and implemented technology at Foster Creek whereby an additional well, a wedge 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-oil ratio. In 2010, we drilled 20 wedge wells (2009 - 18 wells), and at December 31, 2010, there were 33 wedge wells 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 the excess power generated is being sold into the Alberta Power Pool.

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Christina Lake

We have a 50 percent interest in a SAGD oil sands project at Christina Lake which produces from the McMurray formation. The phase B expansion was completed in 2008 which increased gross production capacity to approximately 18,000 barrels per day of bitumen.

Christina Lake phase C was approximately 88 percent complete at December 31, 2010, on budget and on schedule for first production in the third quarter of 2011. This phase is expected to increase total gross bitumen production capacity to approximately 58,000 barrels per day.

We have accelerated the planned completion of phase D by approximately six months and it is expected to be completed in 2013. Regulatory approval for this additional phase was received in 2008.

Additionally, we drilled four wedge wells at Christina Lake in 2010, and at December 31, 2010, there was one wedge well producing.

There have been several innovations to SAGD technology that 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-oil ratio and increasing the overall recovery of the oil in place. Business cases are currently being evaluated for the potential use of this technology in the Christina Lake and Narrows Lake development plans.

Another innovation was undertaken in 2007, whereby a remote water disposal system was utilized to successfully manage bottom water pressures and further reduce the steam-oil ratio.

Pelican Lake

Using a pattern, horizontal well polymer flood, we produce heavy oil from the Cretaceous Wabiskaw formation at our Pelican Lake property, which is located within the Greater Pelican Region in northeast Alberta. In 2010, expansion of the facility infrastructure continued in order to accommodate higher total fluid production volumes associated with infill drilling as well as the continued rollout of the polymer injection program. The polymer flood program was expanded by six new injection wells and 11 new production wells in 2010.

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.

In August 2008, we entered into an agreement with Pembina Pipeline Corporation ("Pembina") to transport blended heavy oil from Utikuma, Alberta to Edmonton, Alberta via Pembina's 100,000 barrels per day capacity pipeline, expected to be in-service in mid-2011. This pipeline will be used to transport heavy oil from the Greater Pelican Region to crude oil markets. The parties also agreed to transport condensate, used as diluent for transporting heavy oil, from Whitecourt, Alberta to Utikuma, Alberta via a 22,000 barrel per day capacity pipeline. The initial term of the agreement is ten years from the pipeline's in-service date.

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New Resource Play assets

Our new resource play assets include our emerging oil sands properties such as Narrows Lake, Grand Rapids and Telephone Lake.

Through our interest in FCCL, we hold an approximate 50 percent interest in the Narrows Lake property, which is located within the Christina Lake Region. In the first quarter of 2010, we initiated the regulatory approval process for Narrows Lake by filing proposed terms of reference for an environmental impact assessment ("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 barrels per day of bitumen to be added in three phases, with the first phase expected to have production capacity of approximately 40,000 barrels per day of bitumen. The project is expected to begin producing in 2016. Our submitted application includes the option to implement the SAP technology at Narrows Lake which would allow the pr oject to be developed in two phases of 65,000 barrels per day, rather than three phases.

Our Grand Rapids project is located in the Greater Pelican Region, where large deposits of bitumen have been identified in the Cretaceous Grand Rapids formation. During the second quarter of 2010, we received approval from the ERCB to begin a pilot project at Grand Rapids. In the fourth quarter of 2010, we received approval from Alberta Environment to start this pilot project. The drilling of a SAGD well pair and construction of associated facilities is complete and steam injection commenced in late 2010. If this pilot is successful, we expect to file a regulatory application by the end of 2011 for a commercial operation with bitumen production capacity of 180,000 barrels per day.

Our Telephone Lake property is located in the Borealis Region. 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 production capacity of 35,000 barrels per day of bitumen. We plan to file an updated joint application and EIA in the fourth quarter of 2011.

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 annualized natural gas production of approximately 23 million cubic feet per day in 2010 (25 million cubic feet per day in 2009). The Government of Alberta's Department of Energy is providing financial assistance in the form of a royalty credit, which is equal to approximately 50 percent of the cash flow lost as a result of the shut-in wells.

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Conventional

We have conventional crude oil and natural gas development and production activities in Alberta and Saskatchewan. Conventional also includes the Weyburn carbon dioxide ("CO_2") miscible flood project as well as our emerging Bakken and Shaunavon properties.

At December 31, 2010, we had an established land position of approximately 5.4 million gross acres (5.2 million net acres), of which approximately 3.7 million gross acres (3.5 million net acres) are developed. The mineral rights on approximately 60 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 2010, we had capital investment of approximately $523 million and drilled approximately 676 net wells. Of our capital expenditures, 68 percent was oil focused, while 32 percent was natural gas focused.

Plans for 2011 include continued drilling, well optimizations, well recompletions (including coalbed methane ("CBM")) and investment in facility infrastructure necessary for continued development of our assets.

The following table summarizes our landholdings at December 31, 2010.

Landholdings – Conventional	Developed		Undeveloped		Total		Average Working
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net	Interest
Suffield	916	907	89	86	1,005	993	99%
Brooks North	570	568	8	8	578	576	100%
Langevin	761	720	415	399	1,176	1,119	95%
Drumheller	359	348	16	13	375	361	96%
Wainwright	361	336	210	205	571	541	95%
Boyer	594	559	280	235	874	794	91%
Weyburn	100	89	384	364	484	453	94%
Shaunavon / Bakken	3	3	72	71	75	74	99%
Other	3	3	261	261	264	264	100%
Total	3,667	3,533	1,735	1,642	5,402	5,175	96%

The following table sets forth 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)	2010	2009	2010	2009	2010	2009
Suffield	12,742	13,822	200	223	46,075	50,989
Brooks North	1,637	1,104	240	260	41,637	44,437
Langevin	7,728	8,386	152	181	33,062	38,553
Drumheller	2,109	2,127	72	82	14,109	15,794
Wainwright	4,414	5,589	3	5	4,914	6,422
Boyer	13	13	24	29	4,013	4,846
Weyburn	16,537	17,791	-	-	16,537	17,791
Shaunavon / Bakken	1,996	656	3	4	2,496	1,323
Total	47,176	49,488	694	784	162,843	180,155

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The following table summarizes our interests in producing wells at December 31, 2010. These figures exclude wells which were capable of producing, but that were not producing, as of December 31, 2010.

Producing Wells – Conventional	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
(number of wells)	Gross	Net	Gross	Net	Gross	Net
Suffield	741	741	10,705	10,683	11,446	11,424
Brooks North	80	80	7,546	7,417	7,626	7,497
Langevin	244	240	4,856	4,840	5,100	5,080
Drumheller	103	100	1,597	1,540	1,700	1,640
Wainwright	452	417	14	4	466	421
Boyer	6	1	1,152	1,150	1,158	1,151
Weyburn	751	457	-	-	751	457
Shaunavon / Bakken	25	25	-	-	25	25
Total	2,402	2,061	25,870	25,634	28,272	27,695

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 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.

We have a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southeast Saskatchewan. The Weyburn unit produces light and medium sour crude 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, 2010, approximately 70 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 16.5 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.

In 2010, we continued evaluating and started developing medium and light oil prospects in the Bakken and lower Shaunavon zones in Saskatchewan, where we drilled 36 wells and increased production to approximately 2,000 barrels per day. Most of the sections of land that we hold in these areas are Crown land.

The following table sets forth net oil wells drilled and daily average oil production figures for the periods indicated.

			Production			
			Light/Medium (bbls/d)		Heavy Oil (bbls/d)	
Net Wells Drilled and Production (annual average)	**Net Wells Drilled**					
	2010	**2009**	**2010**	**2009**	**2010**	**2009**
Suffield	43	40	-	-	12,717	13,798
Brooks North	41	18	1,458	894	-	-
Langevin	22	14	7,529	8,160	-	-
Drumheller	30	28	1,403	1,421	-	-
Wainwright	3	-	452	1,472	3,942	4,090
Boyer	-	-	12	12	-	-
Weyburn	3	-	16,534	17,784	-	-
Shaunavon / Bakken	36	5	1,958	651	-	-
Other	2	-	-	-	-	-
Total	180	105	29,346	30,394	16,659	17,888

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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 infill drilling, up to 16 wells per section, recompletions and optimization of existing wells.

The following table sets forth net gas wells drilled and daily average gas production for the periods indicated.

			Gas Production (MMcf/d)	
Net Wells Drilled and Production (annual average)	**Net Wells Drilled**			
	2010	**2009**	**2010**	**2009**
Suffield	292	170	200	223
Brooks North	149	163	240	260
Langevin	24	109	152	181
Drumheller	29	56	72	82
Other	1	4	30	38
Total	495	502	694	784

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 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.

Included in the Brooks North and Langevin areas is the Belly River Cretaceous formation where Cenovus is producing CBM. In 2010, approximately 900 wells were recompleted which added approximately 17 million cubic feet per day of natural gas production by the end of the year. The CBM assets are long-life and low decline and are expected to generate production for future growth in a capital efficient manner.

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Refining and Marketing

Refining

Through WRB Refining LP ("WRB") we have a 50 percent interest in both the Wood River and Borger Refineries located in Roxana, Illinois and Borger, Texas respectively. ConocoPhillips is the operator and manager 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.

At December 31, 2010, WRB had processing capability to refine approximately 452,000 barrels per day of crude oil. With the completion of the CORE project, the Wood River Refinery will have the ability to process a wider variety of heavy crude oil feedstocks. Our two refineries will then have a combined capacity to process as much as 275,000 barrels per day of heavy crude oil.

Wood River Refinery

At December 31, 2010, the Wood River refinery had a processing capacity of approximately 306,000 barrels per day of 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 Midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the U.S. Midwest. In 2007, the refinery completed the construction of a proprietary sulphur removal unit that produces low-sulphur gasoline. In September 2008, regulatory approval was received to proceed with the construction of the CORE project at Wood River. At December 31, 2010, the CORE project was approximately 91 percent complete. Commissioning of several of the process units has been comple ted with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast. The expansion is expected to increase crude oil refining capacity by 50,000 barrels per day to 356,000 barrels per day and more than double heavy crude oil refining capacity at Wood River to 240,000 barrels per day.

Borger Refinery

At December 31, 2010, the Borger refinery had a processing capacity of approximately 146,000 barrels per day of crude oil, including approximately 35,000 barrels per day of heavy crude oil, and approximately 45,000 barrels per day of NGLs. It processes mainly medium, high-sulphur 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. In July 2007, a new coker with a capacity of approximately 25,000 barrels per day was brought into service along with a new vacuum unit and revamped gas, oil and distillate hydrotreaters. This project has enabled the refinery to process heavy oil blends, particularly Canadian heavy oil, and comply with clean fuel regulations for ultra-low sulphur diesel and low-sulphur gasoline. The project has also enabled compliance with required reductions of sulphur dioxide and other air emissions.

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

Refinery Operations[1]	**2010**	**2009**
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	386	394
Crude Utilization (%)	86	87
Refined Products (Mbbls/d)		
Gasoline	204	223
Distillates	123	120
Other	78	74
Total	405	417

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 carries out third-party purchases and sales of product to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

We also seek to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced products. Details of those 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, 2010.

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. During 2010, our blend volumes (which include diluent added to create a product suitable for pipeline transportation) marketed on behalf of FCCL were 163,472 barrels per day (2009 - 120,894 barrels per day), while our wholly-owned blend, light and medium crude oil volumes marketed were 73,238 barrels per day (2009 - 78,303 barrels per day).

Natural Gas Marketing

Our natural gas is primarily marketed to industrials, other producers and energy marketing companies. In 2010, approximately 20 percent of our sales of natural gas were directly marketed by us to industrials (2009 – approximately 25 percent). The remaining 80 percent of sales of natural gas were marketed to other producers and energy marketing companies (2009 – approximately 75 percent). 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.

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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”). Prior to the year ended December 31, 2010, we presented our reserves estimates in accordance with U.S. disclosure requirements pursuant to an exemption from certain of the NI 51-101 requirements. The exemption expired at the end of 2010. As a result, reserves information for the year ending December 31, 2009 is presented as previously disclosed, using 2009 12 month average constant prices and costs as prescribed by the U.S. Securities and Exchange Commission (“SEC”), and has also been restated to comply with NI 51-101, using McDaniel & Associates Consultants Ltd. (“McDaniel”) January 1, 2010 forecast prices and costs, consistent with the presentation format for December 31, 2010 reserves disclosures, which use McDaniel January 1, 2011 forecast prices and costs. The reserves, contingent resources and prospective resources information provided herein conforms with the disclosure requirements of NI 51-101.

We retain two independent qualified reserves evaluators ("IQREs"), 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 annually. McDaniel evaluated approximately 93 percent of our total proved reserves, located throughout Alberta and Saskatchewan, and GLJ evaluated approximately seven 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 recommend approval of the reserves and resources disclosure to the Board.

The company's reserves are located in Alberta and Saskatchewan, Canada. 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 "Definitions, Notes to Reserves Data Tables and Pricing Assumptions" in conjunction with the disclosure in this statement. The estimates of bitumen, light and medium oil, heavy oil, NGLs, natural gas and CBM reserves 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.

This reserves data and other oil and gas information contained in this AIF is dated February 16, 2011, with an effective date of December 31, 2010. McDaniel's preparation date of the information is February 16, 2011, and GLJ's preparation date is January 26, 2011.

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, cost 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.

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We hold significant freehold title rights which generate production for our account from third parties leasing those lands ("Royalty Interest production"). The Before Royalty volumes presented do not include reserves ("Royalty Interest reserves") associated with this Royalty Interest production. The After Royalty volumes presented include our Royalty Interest reserves. See "Definitions, Notes to Reserves Tables Data, and Pricing Assumptions" below for further information on our Royalty Interests.

Summary of Oil and Gas Reserves at December 31, 2010
(Forecast Prices and Costs)

Company Interest Before Royalties[1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	126	111	79	1,292
Developed Non-Producing	20	13	5	62
Undeveloped	1,008	45	27	36
Total Proved Reserves	1,154	169	111	1,390
Probable Reserves	523	97	49	410
Total Proved plus Probable Reserves	1,677	266	160	1,800

Note:
(1) Does not include Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

Bitumen accounts for approximately 69 percent of our proved reserves Before Royalties, heavy oil accounts for approximately 10 percent, light and medium oil and NGLs account for approximately seven percent, and natural gas and CBM for approximately 14 percent. Before Royalties, approximately 87 percent of Cenovus's proved bitumen reserves are undeveloped. The distinction between developed and undeveloped bitumen reserves, and the strategy for their development, is described further under "Undeveloped Reserves".

Company Interest After Royalties[1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	96	92	67	1,292
Developed Non-Producing	14	10	4	61
Undeveloped	760	36	21	36
Total Proved Reserves	870	138	92	1,389
Probable Reserves	404	72	39	391
Total Proved plus Probable Reserves	1,274	210	131	1,780

Note:
(1) Includes Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

After Royalties, bitumen accounts for approximately 65 percent of our proved reserves, heavy oil accounts for approximately 10 percent, light and medium oil and NGLs account for approximately seven percent, and natural gas and CBM for approximately 18 percent. In the presented After Royalties reserves,

Royalty Interest reserves constitute approximately three percent of natural gas, approximately five percent of light and medium oil and NGL reserves, and approximately one percent of heavy oil reserves. We have no bitumen Royalty Interest reserves.

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Summary of Net Present Value of Future Net Revenue at December 31, 2010
(Forecast Prices and Costs)

	Before Income Taxes Discounted at %/year ($ millions)					Unit Value Before Income Tax Discounted at 10%[1]
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**$/BOE**
Proved Reserves						
Developed Producing	16,118	12,796	10,619	9,102	7,986	22.60
Developed Non-Producing	1,423	888	604	435	325	15.53
Undeveloped	36,936	13,789	6,302	3,300	1,872	7.66
Total Proved Reserves	54,477	27,473	17,525	12,837	10,183	13.16
Probable Reserves	21,163	12,192	6,879	4,031	2,466	11.84
Total Proved plus Probable Reserves	75,640	39,665	24,404	16,868	12,649	12.76

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

	After Income Taxes[1] Discounted at %/year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	12,683	10,153	8,480	7,308	6,443
Developed Non-Producing	1,070	666	454	328	245
Undeveloped	27,637	10,359	4,720	2,442	1,349
Total Proved Reserves	41,390	21,178	13,654	10,078	8,037
Probable Reserves	15,783	9,073	5,076	2,923	1,737
Total Proved plus Probable Reserves	57,173	30,251	18,730	13,001	9,774

Note:
(1) After income tax values are calculated by considering the Company's existing tax pools

Total Future Net Revenue (undiscounted) at December 31, 2010
(Forecast Prices and Costs) ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs [1]	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves	132,911	29,190	38,802	9,414	1,028	54,477	13,087	41,390
Proved plus Probable Reserves	186,276	40,718	53,511	15,234	1,173	75,640	18,467	57,173

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, 2010
(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	8,907	10.24
	Heavy Oil [1]	1,977	14.32
	Light and Medium Crude Oil [1]	2,290	24.89
	Natural Gas [2]	4,351	18.79
	Total	**17,525**	**13.16**
Proved plus Probable Reserves	Bitumen	12,819	10.06
	Heavy Oil [1]	2,870	13.67
	Light and Medium Crude Oil [1]	3,136	23.94
	Natural Gas [2]	5,579	18.81
	Total	**24,404**	**12.76**

Notes:
(1) Including solution gas and other by-products
(2) Including by-products, but excluding solution gas from oil wells

Definitions, Notes to Reserves Data Tables and Pricing Assumptions

The following pricing assumptions, definitions and notes are applicable to the disclosure in this AIF. For definitions in relation to our contingent and prospective resources disclosure, see "Contingent and Prospective Resources" below.

Definitions

1. **After Royalties** means volumes after deduction of royalties and including any royalty interests.

2. **Before Royalties** means volumes before deduction of royalties and excluding any royalty interests.

3. **Company Interest** means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by Cenovus.

4. **Gross** means:
   (a) in relation to wells, the total number of wells in which 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.

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   - **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   Each of the reserves categories (proved and probable) 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 into producing and non-producing.

     - **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 (for example, 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** means:
   (a) in relation to reserves, those reserves related to our royalty entitlement on lands to which we hold freehold title which have been leased to third parties, or reserves related to other royalty interests, such as overriding royalties to which we are entitled.
   (b) in relation to production, the production generated for Cenovus's account pursuant to leasing agreements of our freehold title lands, and other royalty entitlement agreements.

Notes to Reserves Data Tables

- The estimates of future net revenue presented do not represent fair market value.

- For disclosure purposes, we have included NGLs with light and medium oil, and CBM gas with natural gas, as the reserves of each of NGLs and CBM gas are not material relative to the other reported product types.

- Only estimated future well abandonment costs related to reserves wells have been taken into account by the IQREs in determining the aggregate future net revenue therefrom. Further, the abandonment costs only include downhole abandonment costs for the wells considered in the IQREs' evaluation of reserves. Abandonment of other wells, surface reclamation, asset recovery and facility site reclamation costs are not included.

- Future net revenue from reserves excludes cash flows related to our risk management activities.

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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, 2011 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2011.

	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)
2011	85.00	84.20	77.20	66.70	71.10	4.25	2.0	0.975
2012	87.70	88.40	80.40	68.70	73.20	4.90	2.0	0.975
2013	90.50	91.80	82.50	68.60	73.30	5.40	2.0	0.975
2014	93.40	94.80	85.20	70.80	75.60	5.90	2.0	0.975
2015	96.30	97.70	87.90	73.00	78.00	6.35	2.0	0.975
2016	99.40	100.90	90.70	75.40	80.50	6.75	2.0	0.975
2017	101.40	102.90	92.50	76.90	82.10	7.10	2.0	0.975
2018	103.40	104.90	94.30	78.40	83.70	7.40	2.0	0.975
2019	105.40	107.00	96.20	80.00	85.40	7.60	2.0	0.975
2020	107.60	109.20	98.20	81.60	87.10	7.75	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 development costs deducted in the estimation of future net revenue calculated utilizing forecast prices and costs, undiscounted and using a discount rate of 10 percent per annum for the years indicated.

Reserves Category ($ millions)	2011	2012	2013	2014	2015	Remainder	Total Undiscounted	Total Discounted at 10%
Proved Reserves	790	745	436	327	195	6,921	9,414	3,388
Proved plus Probable Reserves	1,080	1,258	1,106	921	710	10,159	15,234	6,680

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 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.

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Reserves Reconciliation

The following tables provide a reconciliation of our company interest reserves Before Royalties for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2010, presented using forecast prices and costs. All reserves are located in Canada.

Reserves Reconciliation by Principal Product Type and Reserves Category
(Forecast Prices and Costs)

Company Interest Proved – Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC)[1]	866	165	112	1,529
Transition to NI 51-101 Standards[2]	-	(1)	(3)	128
December 31, 2009 (NI 51-101)	866	164	109	1,657
Extensions and Improved Recovery	270	9	11	45
Discoveries	-	-	-	-
Technical Revisions	40	15	1	60
Economic Factors	-	-	-	(18)
Acquisitions	-	-	-	-
Dispositions	-	(5)	-	(87)
Production[3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,154**	**169**	**111**	**1,390**

Company Interest Probable – Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC)[1]	479	104	53	436
Transition to NI 51-101 Standards[2]	-	(1)	(2)	52
December 31, 2009 (NI 51-101)	479	103	51	488
Extensions and Improved Recovery	132	5	(1)	12
Discoveries	-	-	-	-
Technical Revisions	(88)	(10)	(1)	(82)
Economic Factors	-	-	-	7
Acquisitions	-	-	-	-
Dispositions	-	(1)	-	(15)
Production	-	-	-	-
December 31, 2010	**523**	**97**	**49**	**410**

Company Interest Proved plus Probable – Before Royalties

	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas (Bcf)
December 31, 2009 (SEC)[1]	1,345	269	165	1,965
Transition to NI 51-101 Standards[2]	-	(2)	(5)	180
December 31, 2009 (NI 51-101)	1,345	267	160	2,145
Extensions and Improved Recovery	402	14	10	57
Discoveries	-	-	-	-
Technical Revisions	(48)	5	-	(22)
Economic Factors	-	-	-	(11)
Acquisitions	-	-	-	-
Dispositions	-	(6)	-	(102)
Production[3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,677**	**266**	**160**	**1,800**

Notes:

(1) References in the tables to December 31, 2009 (SEC) numbers are to the previously disclosed estimates as of that date prepared by the IQREs in accordance with U.S. disclosure requirements using constant prices and costs as prescribed by the SEC.

(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of Royalty Interest reserves from the Before Royalties reserves totals.

(3) Production used for the reserves reconciliation differs from reported production. Company Interest Before Royalties production for reserves includes Cenovus's share of gas volumes provided to Cenovus's share of the FCCL partnership for steam generation, but does not include royalty interest production, as prescribed by NI 51-101.

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In 2010, proved and proved plus probable bitumen reserves increased by approximately 33 and 25 percent respectively. This was primarily a result of receiving regulatory approval to expand the development area at Foster Creek and from improvements to overall recovery based on operating performance. Incremental recovery from wedge wells, drilled between existing producers, and improved recovery resulting from better than expected drainage from existing wells also contributed to the increase.

In 2010, proved heavy oil reserves increased by approximately two percent primarily as a result of expanding polymer flood areas and their successful performance at Pelican Lake. Probable heavy oil reserves decreased by approximately seven percent as result of transfers to proved reserves. Proved plus probable reserves decreased by approximately one percent.

In 2010, proved light and medium oil and NGLs reserves decreased by approximately one percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and their successful performance at Weyburn being offset by current year production. Probable light and medium oil and NGLs reserves decreased by eight percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately three percent.

In 2010, proved natural gas reserves declined by approximately nine percent as extensions and technical revisions did not offset production and the divestiture of some of our natural gas assets. Probable natural gas reserves and proved plus probable reserves declined by approximately six percent and eight percent respectively.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and probable undeveloped reserves have been estimated by the IQREs in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook. In general, undeveloped reserves are scheduled to be developed within the next one to 40 years.

Proved Undeveloped Reserves – Company Interest Before Royalties

	Bitumen (MMbbls)		Light and Medium Oil and NGLs (MMbbls)		Heavy Oil (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior[1]	617	617	30	30	31	31	226	226
2008	6	560	8	29	16	45	46	150
2009	190	734	7	28	8	46	10	35
2010	295	1,008	5	27	5	45	18	36

Probable Undeveloped Reserves – Company Interest Before Royalties

	Bitumen (MMbbls)		Light and Medium Oil and NGLs (MMbbls)		Heavy Oil (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior[1]	616	616	-[2]	-[2]	-[2]	-[2]	-[2]	-[2]
2008	12	625	-[2]	-[2]	-[2]	-[2]	-[2]	-[2]
2009	5	467	26	26	43	43	38	38
2010	171	506	2	21	-	37	16	30

Note:

(1) First Attributed Undeveloped Reserves have been estimated as equal to Total at Year-End Undeveloped Reserves as historical information is not available.

(2) Historical information is not available.

Development of Proved Undeveloped Reserves

Bitumen

At the end of 2010, we had proved undeveloped bitumen reserves of 1,008 million barrels Before Royalties, or approximately 87 percent of our total proved bitumen reserves. Of our 523 million barrels of probable bitumen reserves, 506 million barrels, or approximately 97 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.

Development of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. Reserves will be classified as probable if the stratigraphic well requirement for proved reserves is not met, 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. Once that is established and the 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 over 40 years, based on existing facilities. Production of the current proved developed portion is estimated to take about ten years.

Oil

We have a significant medium oil CO_2 EOR project at Weyburn and a significant heavy oil waterflood/polymer flood EOR project at Pelican Lake. These projects occur in large, well-developed reservoirs, where undeveloped reserves are not necessarily defined by the absence of drilling, but by anticipated improved recovery associated with development of the EOR schemes. Extending both EOR schemes within the projects requires intensive capital investment in infrastructure development and will occur over many years.

At Weyburn, investment in undeveloped reserves is projected to continue for well over 30 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 nine 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 the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a summary of risks and uncertainties affecting Cenovus please refer to "Risk Factors" in this AIF.

Contingent and Prospective Resources

We retain McDaniel to evaluate and prepare reports on all of our bitumen contingent and prospective resources. The following resources information is derived from the reports prepared for us by McDaniel.

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. SAGD projects that are producing from the McMurray-Wabiskaw formations at Foster Creek and Christina Lake are used as performance analogs for the majority of our properties with contingent and prospective resources. 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") technologies. SAGD involves injecting steam into horizontal wells drilled into the bitumen formation and recovering heated bitumen and water from producing wells located below the injection wells. CSS involves injecting steam into a well and then producing water and heated bitumen from the same wellbore. Such alternating injection and production cycles are repeated a number of times for a given wellbore. Both of these techniques have a surface footprint comparable to conventional oil production. We have no bitumen resources that require mining techniques for recovery.

All of Cenovus's current contingent and prospective resources are associated with clastic or sandstone formations. Cenovus has also identified significant amounts of bitumen in the Grosmont carbonate formation for which we have extensive mineral rights. To date, McDaniel has not recognized the commercial viability of recovery processes in any carbonate formation, including the Grosmont. A successful pilot in the Grosmont or a commercial project in an analogous carbonate reservoir would have to take place before McDaniel would consider bitumen from these carbonates to be exploitable or recoverable. Cenovus is planning a pilot for carbonate oil production from the Grosmont formation and there are other industry pilots planned or underway.

In addition to the reserve definitions provided in the preceding sections, the following definitions from the COGE Handbook were used to prepare the disclosure that follows.

Contingent Resources are those quantities of petroleum 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.

For Cenovus, contingencies which must be overcome to enable the reclassification of bitumen contingent resources as reserves include regulatory application submission with no major issues raised, access to markets, and intent to proceed by the operator and partners as evidenced by a development plan with major capital expenditures planned within five years.

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 2010 reserves evaluation, which comply with NI 51-101 requirements.

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Prospective Resources are those quantities of 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, 2009[1]	December 31, 2010[2]
Economic Contingent Resources[3]		
Low Estimate	3.9	4.4
Best Estimate	5.4	6.1
High Estimate	7.3	8.0
Prospective Resources[4]		
Low Estimate	7.8	7.3
Best Estimate	12.6	12.3
High Estimate	21.4	21.7

Notes:
(1) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.
(2) Refers to estimates prepared by McDaniel using the same forecast prices and costs as used in the 2010 reserves estimates, McDaniel January 1, 2011 forecast prices and costs.
(3) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.
(4) 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.

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Best estimate economic contingent resources increased 0.7 billion barrels or 13 percent relative to 2009. This increase is primarily a result of our stratigraphic well drilling converting prospective resources to contingent resources, and positive technical revisions to volumetric and recovery factor estimates. There are no material differences in bitumen economic contingent resource estimates determined using either SEC or NI 51-101 pricing.

Best estimate prospective resources declined 0.3 billion barrels or two percent relative to 2009, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic drilling.

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]
Opening Balance, December 31, 2009[3]	1.345	5.4	12.6
Transfers between Categories			
Additions from other resource categories	0.138	0.6	-

Reductions to other resource categories	-	(0.1)	(0.6)
Additions and Revisions Net of Transfers	0.216	0.3	0.3
Net Acquisitions and Dispositions	-	(0.1)	-
Production	(0.022)	-	-
Closing Balance, December 31, 2010	**1.677**	**6.1**	**12.3**

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.
(3) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production and cash flow. For example, approval for expansion of the Foster Creek development area, in addition to moving some probable reserves to proved reserves, also moved some contingent resources to proved and probable reserves. Similarly, the stratigraphic well program at Pelican Lake moved some prospective resources to contingent resources. The overall reduction of prospective resources is the expected outcome of a successful stratigraphic well program, which converts undiscovered resources to discovered resources.

All classifications of bitumen reserves and resources increased because of higher recoveries due to the improvement in bitumen recovery performance at our Foster Creek and Christina Lake projects resulting from improved operating performance and the use of wedge wells. 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 improve overall recovery from our bitumen assets as technology develops.

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Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table summarizes our interests in producing wells, at December 31, 2010.

	Oil		Gas		Total	
Producing wells[1][2]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta:						
Oil Sands	650	549	490	467	1,140	1,016
Conventional	1,626	1,579	25,870	25,634	27,496	27,213
Total Alberta	2,276	2,128	26,360	26,101	28,636	28,229
Saskatchewan:						
Conventional	776	482	-	-	776	482
Total Saskatchewan	776	482	-	-	776	482
Total	3,052	2,610	26,360	26,101	29,412	28,711

Notes:
(1) Cenovus also has varying royalty interests in 7,577 natural gas wells and 3,906 crude oil wells which are producing.
(2) Includes wells containing multiple completions as follows: 23,854 gross natural gas wells (23,625 net wells) and 1,516 gross crude oil wells (1,306 net wells).

The following table summarizes our interests in non-producing wells at December 31, 2010.

	Oil		Gas		Total	
Non-producing wells[1]	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta:						
Oil Sands	241	162	689	605	930	767
Conventional	655	634	969	948	1,624	1,582
Total Alberta	896	796	1,658	1,553	2,554	2,349
Saskatchewan:						
Conventional	137	94	36	36	173	130
Total Saskatchewan	137	94	36	36	173	130
Total	1,033	890	1,694	1,589	2,727	2,479

Note:
(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells does not include other types of wells such as stratigraphic test wells, service wells, or wells that have been abandoned.

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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**
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
2008:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	1	1	5	3	2	1	8	5	34	42	5
Total Canada	1	1	5	3	2	1	8	5	34	42	5

	Development Wells Drilled										
	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
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
2008:											
Oil Sands	41	21	13	13	4	4	58	38	41	99	38
Conventional	105	92	1,489	1,372	7	7	1,601	1,471	503	2,104	1,471
Total Canada	146	113	1,502	1,385	11	11	1,659	1,509	544	2,203	1,509

In addition to the disclosure above, we drilled stratigraphic test wells during the year ended December 31, 2010, with Oil Sands having drilled 259 gross wells (178 net wells) and Conventional having drilled 11 gross wells (9 net wells).

In addition to the disclosure above, we drilled service wells during the year ended December 31, 2010, with Oil Sands having drilled 68 gross wells (44 net wells) and Conventional having drilled 30 gross wells (20 net wells).

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Interest in Material Properties

The following table summarizes our developed, undeveloped and total landholdings at December 31, 2010.

	Developed		Undeveloped[1]		Total[2]	
	Gross	Net	Gross	Net	Gross	Net
			(thousands of acres)			
Alberta:						
Oil Sands						
– Crown[3]	696	597	1,845	1,455	2,541	2,052
Conventional						
– Fee[4]	1,913	1,913	440	440	2,353	2,353
– Crown[3]	1,571	1,463	372	306	1,943	1,769
– Freehold[5]	51	42	35	32	86	74
Total Alberta	4,231	4,015	2,692	2,233	6,923	6,248
Saskatchewan:						
Conventional						
– Fee[4]	69	69	437	437	506	506
– Crown[3]	47	34	162	141	209	175
– Freehold[5]	13	9	28	25	41	34
Total Saskatchewan	129	112	627	603	756	715
Manitoba:						
Conventional - Fee[4]	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,363	4,130	3,580	3,097	7,943	7,227

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 now includes all fee 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.

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Properties With No Attributed Reserves

We have approximately 5.1 million gross acres (4.7 million net acres) of unproved properties. These properties are planned for current and future development in both our oil sands and conventional oil and gas operations.

We have rights to explore, develop, and exploit approximately 90,000 net acres that could potentially expire by December 31, 2011, 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 $6 billion (approximately $529 million, discounted at 10 percent) at December 31, 2010, of which we expect to pay approximately $104 million in the next three financial years. We expect to incur these costs on approximately 35,000 net wells.

Of the undiscounted future cost of 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.

Tax Horizon

We expect to pay income tax in 2011.

Costs Incurred

The following table summarizes our costs incurred for the year ended December 31, 2010.

	2010
	($ millions)
Acquisitions	
– Unproved	31
– Proved	17
Total acquisitions	48
Exploration costs	114
Development costs	1,260
Total costs incurred	1,422

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Forward Contracts

Cenovus has, as part of our ordinary business operations, a number of delivery commitments to provide crude oil and natural gas. We believe that we have sufficient reserves of natural gas and crude oil to meet these commitments.

Production Estimates

The following table summarizes the estimated 2011 average daily volume of gross production for all properties held on December 31, 2010 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 dispositions.

2011 Estimated Production		
Forecast Prices and Costs	**Proved**	**Proved plus Probable**
Bitumen (bbls/d) (1)	62,775	63,925
Light and Medium Crude Oil (bbls/d)	28,861	30,803
Heavy Oil (bbls/d)	38,486	40,530
Natural Gas (MMcf/d)	646	671
Natural Gas Liquids (bbls/d)	816	882
Total Production (BOE/d) (2)	238,535	247,956
Less: Royalty Interest Production (BOE/d) (3)	(8,961)	(9,382)
Total Company Interest Before Royalties Production (BOE/d)	229,574	238,574

Notes:

(1) Includes Foster Creek production of 52,662 bbls/d for Proved and 53,350 bbls/d for Proved plus Probable.

(2) Includes Royalty Interest production.

(3) Not derived from IQRE reports. Represents a Company estimate derived from the ratio of 2010 Royalty Interest Production to 2010 total production excluding bitumen. There is no Royalty Interest production associated with our bitumen.

Production History

The following tables summarize our daily production volumes, before deduction of royalties, on a quarterly basis for the periods indicated.

	Production Volumes - 2010				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	51,147	52,183	50,269	51,010	51,126
Christina Lake	7,898	8,606	7,838	7,716	7,420
Pelican Lake	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 Production	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.

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	Production Volumes - 2009				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	37,725	47,017	40,367	34,729	28,554
Christina Lake	6,698	7,319	6,305	6,530	6,635
Pelican Lake	24,870	23,804	25,671	23,989	26,029
Senlac (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 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 Production	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.

	Production Volumes - 2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	26,220	29,241	27,289	21,244	27,062
Christina Lake	4,279	6,170	4,620	3,670	2,630
Pelican Lake	27,324	24,975	27,826	27,306	29,211
Senlac	3,223	2,623	3,135	3,281	3,861
	61,046	63,009	62,870	55,501	62,764
Conventional Liquids					
Heavy Oil	19,062	17,834	18,354	19,383	20,694
Light and Medium Oil	31,492	31,173	31,100	31,306	32,399
Natural Gas Liquids (1)	1,203	1,158	1,167	1,204	1,283
Total Oil and Natural Gas Liquids	112,803	113,174	113,491	107,394	117,140
Natural Gas (MMcf/d)					
Oil Sands	88	65	91	103	93
Conventional	866	840	856	882	883
Total Natural Gas Production	954	905	947	985	976
Total (BOE/d)	271,803	264,007	271,324	271,561	279,807

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

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Per-Unit Results

The following tables summarize our per-unit results on a quarterly basis, before deduction of royalties, for the periods indicated.

	Per-Unit Results–2010				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl)					
Price(1)	58.76	58.76	58.51	54.75	63.33
Royalties	9.08	11.41	9.56	9.38	5.76
Transportation and blending	2.42	2.54	2.40	2.40	2.33
Operating	10.44	10.00	10.35	10.36	11.11
Netback	36.82	34.81	36.20	32.61	44.13
Heavy Oil – Christina Lake ($/bbl)					
Price(1)	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	16.56	17.40	15.94	16.50	16.41
Netback	35.72	37.43	34.78	31.78	39.11
Heavy Oil – Pelican Lake ($/bbl)					
Price[1]	62.65	61.38	58.93	62.05	68.04
Royalties	12.96	12.76	10.62	14.06	14.34
Transportation and blending	1.42	1.04	1.77	1.52	1.30
Operating	12.76	13.37	13.26	13.29	11.23
Netback	35.51	34.21	33.28	33.18	41.17
Heavy Oil - Oil Sands ($/bbl)					
Price	59.76	59.35	58.41	56.83	64.61
Royalties	9.53	10.79	9.30	10.03	7.94
Production and mineral taxes	-	-	-	-	-
Transportation and blending	2.25	2.08	2.35	2.35	2.23
Operating	11.70	11.54	11.83	11.81	11.65
Netback	36.28	34.94	34.93	32.64	42.79
Heavy Oil - Conventional ($/bbl)					
Price	63.18	60.45	59.40	61.35	71.16
Royalties	9.01	8.01	7.29	9.65	10.99
Production and mineral taxes	0.19	0.05	0.17	0.10	0.44
Transportation and blending	0.56	0.45	0.60	0.60	0.59
Operating	12.08	12.47	11.52	12.95	11.45
Netback	41.34	39.47	39.82	38.05	47.69
Total - Heavy Oil ($/bbl)					
Price[1]	60.33	59.53	58.59	57.57	65.76
Royalties	9.44	10.36	8.95	9.97	8.48
Production and mineral taxes	0.03	0.01	0.03	0.02	0.08
Transportation and blending	1.97	1.83	2.04	2.06	1.94
Operating	11.77	11.68	11.77	11.99	11.61
Netback	37.12	35.65	35.80	33.53	43.65
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
Production and mineral taxes	2.55	2.45	2.44	3.08	2.25
Transportation and blending	1.66	1.89	1.81	1.51	1.45
Operating	12.27	12.99	12.02	12.84	11.25
Netback	45.85	47.96	42.78	38.54	53.78

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	Per-Unit Results–2010				
	Year	Q4	Q3	Q2	Q1
Total - Crude Oil ($/bbl)					
Price	62.98	62.75	60.86	59.51	68.87
Royalties	9.41	9.72	9.03	10.01	8.85
Production and mineral taxes	0.62	0.59	0.59	0.71	0.59
Transportation and blending	1.90	1.84	1.99	1.94	1.83
Operating	11.89	11.99	11.83	12.19	11.52
Netback	39.16	38.61	37.42	34.66	46.08
Conventional - Natural Gas Liquids ($/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 ($/bbl)					
Price	62.96	62.75	60.80	59.50	68.85
Royalties	9.33	9.63	8.96	9.93	8.78
Production and mineral taxes	0.62	0.59	0.59	0.71	0.59
Transportation and blending	1.88	1.82	1.97	1.94	1.83
Operating	11.78	11.84	11.72	12.08	11.42
Netback	39.35	38.87	37.56	34.84	46.23
Total - Natural Gas ($/Mcf)					
Price	4.09	3.55	3.68	3.78	5.27
Royalties	0.07	(0.04)	0.08	0.07	0.14
Production and mineral taxes	0.02	0.02	0.03	(0.04)	0.07
Transportation and blending	0.17	0.16	0.15	0.15	0.21
Operating	0.96	1.02	0.94	0.94	0.94
Netback	2.87	2.39	2.48	2.66	3.91
Total ($/BOE)					
Price	44.01	42.82	41.49	41.46	50.16
Royalties	4.93	4.90	4.73	5.26	4.81
Production and mineral taxes	0.37	0.35	0.38	0.24	0.52
Transportation and blending	1.45	1.40	1.42	1.43	1.53
Operating[2]	8.81	9.08	8.70	8.93	8.53
Netback	28.45	27.09	26.26	25.60	34.77

Notes:

(1) The heavy oil price 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; Total – Heavy Oil - $26.88/bbl.

(2) Operating costs for the year include costs related to long-term incentives of $ 0.15 / BOE.

Impact of Realized Financial Hedging	2010	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

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	Per-Unit Results–2009				
	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl)					
Price[1]	55.55	63.60	62.20	54.43	33.44
Royalties	1.42	2.31	1.85	0.66	0.22
Transportation and blending	2.51	1.71	2.50	3.45	2.69
Operating	11.87	10.43	10.85	11.81	15.91
Netback	39.75	49.15	47.00	38.51	14.62
Heavy Oil – Christina Lake ($/bbl)					
Price[1]	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 ($/bbl)					
Price[1]	54.77	62.73	61.87	55.39	38.66
Royalties	10.98	12.08	12.27	10.93	8.57
Transportation and blending	0.30	(0.02)	0.67	0.06	0.45
Operating	9.59	11.64	7.03	9.74	10.15
Netback	33.90	39.03	41.90	34.66	19.49
Heavy Oil - Oil Sands ($/bbl)					
Price	55.09	62.75	62.23	55.18	35.47
Royalties	4.98	5.37	5.66	4.86	3.69
Production and mineral taxes	0.04	0.02	0.07	0.06	-
Transportation and blending	1.81	1.14	2.15	2.16	1.85
Operating	11.49	11.41	9.69	11.53	13.89
Netback	36.77	44.81	44.66	36.57	16.04
Heavy Oil - Conventional ($/bbl)					
Price	55.29	62.09	64.62	56.00	37.71
Royalties	5.47	8.61	8.39	4.13	0.61
Production and mineral taxes	0.14	0.13	(0.04)	0.44	0.02
Transportation and blending	1.91	1.59	1.22	2.75	2.11
Operating	9.47	12.06	9.31	9.72	6.91
Netback	38.30	39.70	45.74	38.96	28.06
Total - Heavy Oil ($/bbl)					
Price[1]	55.14	62.63	62.72	55.36	35.99
Royalties	5.08	5.95	6.22	4.70	2.98
Production and mineral taxes	0.06	0.04	0.04	0.14	-
Transportation and blending	1.83	1.22	1.96	2.28	1.91
Operating	11.07	11.52	9.61	11.13	12.27
Netback	37.10	43.90	44.89	37.11	18.83
Light and Medium Oil ($/bbl)					
Price	63.34	71.82	68.15	65.28	48.09
Royalties	7.39	11.72	8.09	6.56	3.14
Production and mineral taxes	2.40	1.70	2.57	1.98	3.37
Transportation and blending	0.98	0.70	0.83	1.18	1.21
Operating	9.93	9.53	10.00	9.53	10.67
Netback	42.64	48.17	46.66	46.03	29.70
Total - Crude Oil ($/bbl)					
Price	57.22	64.85	64.00	57.95	39.40
Royalties	5.67	7.34	6.66	5.18	3.03
Production and mineral taxes	0.65	0.44	0.64	0.62	0.95
Transportation and blending	1.61	1.10	1.69	2.00	1.71
Operating	10.78	11.04	9.70	10.72	11.82
Netback	38.51	44.93	45.31	39.43	21.89

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	Per-Unit Results–2009				
	Year	Q4	Q3	Q2	Q1
Conventional - 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
Production and mineral taxes	0.65	0.44	0.63	0.61	0.94
Transportation and blending	1.60	1.09	1.67	1.98	1.69
Operating	10.67	10.94	9.61	10.61	11.69
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
Production and mineral taxes	0.05	0.03	0.04	0.07	0.05
Transportation and blending	0.15	0.12	0.16	0.16	0.18
Operating	0.86	0.81	0.84	0.83	0.94

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
Production and mineral taxes	0.46	0.30	0.43	0.52	0.58
Transportation and blending	1.24	0.91	1.29	1.41	1.34
Operating[2]	7.71	7.85	7.24	7.52	8.27
Netback	27.60	31.43	28.25	26.85	23.71

Notes:

(1) The heavy oil price 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; Total – Heavy Oil - $19.68/bbl.

(2) Operating costs for the year include costs related to long-term incentives of $0.09/BOE.

Impact of Realized Financial Hedging	**2009**	**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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	Per-Unit Results–2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl)					
Price[1] [2]	64.94	21.42	94.96	96.51	60.07
Royalties	0.66	0.35	0.96	0.91	0.53
Transportation and blending	2.33	2.28	2.03	2.63	2.44
Operating	15.04	12.09	14.74	19.87	14.80
Netback	46.91	6.70	77.23	73.10	42.30
Heavy Oil – Christina Lake ($/bbl)					
Price[1] [2]	62.87	35.46	89.43	81.81	56.97
Royalties	0.60	0.34	0.94	0.77	0.40
Transportation and blending	3.57	3.33	2.90	3.62	5.20
Operating	23.95	16.88	22.79	30.92	33.42
Netback	34.75	14.91	62.80	46.50	17.95
Heavy Oil – Pelican Lake ($/bbl)					
Price[1]	78.15	38.91	96.43	105.61	70.92
Royalties	15.75	7.85	19.88	21.82	13.29
Transportation and blending	0.31	0.07	0.80	0.23	0.14
Operating	8.01	8.39	6.02	9.80	7.83
Netback	54.08	22.60	69.73	73.76	49.66
Heavy Oil - Oil Sands ($/bbl)					
Price	71.28	30.11	95.59	99.82	65.57
Royalties	7.98	3.59	10.64	11.47	6.85
Production and mineral taxes	0.07	0.03	0.08	0.08	0.10
Transportation and blending	1.50	1.48	1.54	1.49	1.48
Operating	12.56	11.06	11.44	15.78	12.35
Netback	49.17	13.95	71.89	71.00	44.79
Heavy Oil - Conventional ($/bbl)					
Price	78.61	46.83	105.10	90.49	69.13
Royalties	10.95	6.45	14.17	12.98	9.75
Production and mineral taxes	0.08	0.20	0.18	(0.31)	0.26
Transportation and blending	2.72	2.82	3.57	2.59	2.06
Operating	8.42	6.85	7.69	9.29	9.37
Netback	56.44	30.51	79.49	65.94	47.69
Total - Heavy Oil ($/bbl)					
Price[1]	73.06	33.37	97.80	97.36	66.57
Royalties	8.70	4.15	11.46	11.87	7.66
Production and mineral taxes	0.07	0.06	0.10	(0.02)	0.14
Transportation and blending	1.79	1.74	2.01	1.78	1.64
Operating	11.55	10.24	10.56	14.07	11.52
Netback	50.95	17.18	73.67	69.66	45.61
Light and Medium Oil ($/bbl)					
Price	89.87	49.88	111.91	109.29	88.58
Royalties	11.22	4.10	14.90	14.87	11.03
Production and mineral taxes	3.45	2.55	4.71	3.99	2.57
Transportation and blending	1.23	1.19	1.39	1.22	1.11
Operating	9.66	9.19	8.33	11.14	9.97
Netback	64.31	32.85	82.58	78.07	63.90
Total - Crude Oil ($/bbl)					
Price	77.80	37.88	101.77	100.82	72.84
Royalties	9.41	4.14	12.43	12.74	8.62
Production and mineral taxes	1.02	0.74	1.39	1.14	0.83
Transportation and blending	1.63	1.59	1.84	1.61	1.49
Operating	11.02	9.95	9.94	13.22	11.08
Netback	54.72	21.46	76.17	72.11	50.82

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	Per-Unit Results–2008				
	Year	Q4	Q3	Q2	Q1
Conventional - Natural Gas Liquids ($/bbl)					
Price	82.32	54.51	102.20	97.32	75.33
Royalties	1.40	1.55	1.78	1.21	1.22
Netback	80.92	52.96	100.42	96.11	74.11
Total Liquids ($/bbl)					
Price	77.84	38.04	101.77	100.78	72.87
Royalties	9.32	4.11	12.32	12.61	8.54
Production and mineral taxes	1.01	0.73	1.38	1.13	0.82
Transportation and blending	1.62	1.58	1.82	1.60	1.47
Operating	10.90	9.85	9.83	13.08	10.95
Netback	54.99	21.77	76.42	72.36	51.09
Total - Natural Gas ($/Mcf)					
Price	8.17	6.82	8.97	9.58	7.21
Royalties	0.42	0.19	0.51	0.59	0.37
Production and mineral taxes	0.11	0.07	0.16	0.15	0.06
Transportation and blending	0.24	0.25	0.24	0.22	0.24
Operating	0.84	0.84	0.61	0.95	0.98
Netback	6.56	5.47	7.45	7.67	5.56
Total ($/BOE)					
Price	60.99	39.67	73.74	74.76	55.55
Royalties	5.35	2.43	6.91	7.18	4.85
Production and mineral taxes	0.80	0.54	1.13	0.99	0.54
Transportation and blending	1.51	1.54	1.61	1.44	1.45
Operating[3]	7.49	7.14	6.21	8.64	7.97
Netback	45.84	28.02	57.88	56.51	40.74

Notes:

(1) The heavy oil price for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $48.61/bbl; Christina Lake - $47.93/bbl; Pelican Lake - $17.64/bbl; Total – Heavy Oil - $31.04/bbl.

(2) The Foster Creek price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $5.52/bbl; Q4 2008 - $15.26/bbl; Q3 2008 - $3.73/bbl); the Christina Lake price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $1.98/bbl; Q4 2008 - $5.34/bbl).

(3) Operating costs for the year include a recovery of costs related to long-term incentives of $0.10/BOE.

Impact of Realized Financial Hedging	2008	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(5.35)	3.10	(8.03)	(11.05)	(5.89)
Natural Gas ($/Mcf)	(0.24)	1.27	(1.11)	(1.33)	0.32
Total ($/BOE)	(3.05)	5.67	(7.24)	(9.22)	(1.32)

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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 certain 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 2010 and 2009.

	2010	2009
	($ millions)	
Capital Investment		
Upstream		
Foster Creek	278	262
Christina Lake	346	224
Total	624	486
Pelican Lake	104	72
Other Oil Sands	139	71
Conventional	523	466
	1,390	1,095
Refining and Marketing	656	1,033
Corporate	76	34
Capital Investment	2,122	2,162
Acquisitions	86	148
Divestitures	(307)	(367)
Net Acquisition and Divestiture Activity	(221)	(219)
Net Capital Investment	1,901	1,943

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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 p lans 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 47;Risk Factors – Climate Change Regulations”.

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. Some of the climate change legislation being contemplated in the U.S. would require refiners to obtain emission allowances for emissions of GHGs, including CO_2 based on the carbon content of their fuels. If this type of legislation is enacted into law, this could have a material impact on the cost structure of refined petroleum products that would be passed onto the consumer.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2010, 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 2011. Refer to “Risk Factors – Environmental Regulations” for further information on environmental protection matters affecting Cenovus.

Social and Environmental Policies

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. During 2010 our CR policy was revised through a process focused on engagement with employees 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. It was officially launched on November 30, 2010 and is available on our website www.cenovus.com.

Cenovus’s CR policy focuses on six 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 CR reporting, which is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

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The 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. Cenovus 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 Cenovus will continue to rollout the CR policy to ensure the commitments articulated are understood and embedded throughout the organization. This will include: 1) a new CR poster distributed across the company; 2) four videos highlighting different commitments of the CR policy; 3) a news feed highlighting related employee stories; 4) a new interactive employee e-learning training tool; and 5) a presentation delivered at on-boarding sessions for new hires.

In addition, the CR policy will be included as a component in the implementation of the new Cenovus Operating Management System, which will be introduced across the company in 2011. Current steps that Cenovus already has 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) corporate responsibility performance metrics to track our progress; (iii) an energy efficiency program that focuses on reducing energy use at Cenovus’s operations and supports initiatives at the community level while also incentivizing employees to reduce energy use in their homes; (iv) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Cenovus policies or practices and other regulations; (v) an Integrity Helpline that provides an addition al avenue for Cenovus’s stakeholders to raise their concerns as well as the corporate responsibility website which allows people to write to Cenovus about non-financial issues of concern; (vi) 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 (vii) a requirement for acknowledgement and sign-off on key policies from our Board and employees. Our Board approves the CR policy on recommendation of the Safety, Environment and Responsibility Committee, is advised of significant policy contraventions and receives updates on trends, issues or events which could impact Cenovus.

Employees

The following table summarizes our full-time equivalent (“FTE”) employees at December 31, 2010.

	FTE Employees
Oil Sands	823
Conventional	527
Refining and Marketing	67

Cenovus-wide	958
Total	2,375

We also engage a number of contractors and service providers. Refer to “Risk Factors – Key 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., a limited partnership. 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 and Chief Operating Officer of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, LP, and as Interim President and 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 Energ y Transfer Equity, LP. 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 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 and Chief Executive Officer of Sherritt International Corporation, a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity. He is also Chairman of The Westaim Corporation and a director of OPTI Canada Inc.
Brian C. Ferguson[8] Calgary, Alberta, Canada	2009	Mr. Ferguson became President & Chief Executive Officer of Cenovus on November 30, 2009. He was previously appointed as Executive Vice-President & Chief Financial Officer of Encana in March, 2006. At the time of the merger between Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002, Mr. Ferguson was appointed Executive Vice-President, Corporate Development with responsibility for investor relations, business development, which included corporate strategic planning, acquisitions and divestitures, and corporate reserve evaluations, and the legal and corporate secretarial functions. 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 and a member of the Canadian Institute of Chartered Accountants (CICA) and the Ca nadian Council of Chief Executives. He previously served as Chairman of CICA's Risk Oversight and Governance Board.

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Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
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[2,5,6,7] Dallas, Texas, United States	2009	Mr. Rampacek is a director of Enterprise Products Holdings, LLC, the sole general partner of Enterprise Products Partners, L.P., a director of Flowserve Corporation 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 and Managing Partner of Deloitte & Touche LLP and then acted as Senior Counsel until his retirement in May 2008. Mr. Taylor is also a member of the Canadian Institute of Chartered Accountants and Fellow of the Institute of Chartered Accountants of Ontario.
Wayne G. Thomson[2,5,6,7] Calgary, Alberta, Canada	2009	Mr. Thomson is Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves. He is also a director of Virgin Resources Limited, the Chairman of TG World Energy Corp. and a director of Orion Oil & Gas Corporation. 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.

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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.
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.

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Name and Residence	Office Held and Principal Occupation During the Past Five Years
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, 2010, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,176,735 Common Shares or approximately 0.16 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of our directors and officers are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of Cenovus.

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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 annual information form, or has been, within ten years before the date of this annual information form, 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 annual information form, or has been within ten years before the date of this annual information form, 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 ten years before the date of this annual information form, 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. 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 annual information form.

Composition of the Audit Committee

The Audit Committee consists of three members, each of whom are 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 during fiscal 2010 and 2009.

($ thousands)	**2010**	**2009**[5]
Audit Fees[1]	1,996	-
Audit-Related Fees[2]	47	-
Tax Fees[3]	157	-
All Other Fees[4]	18	-
Total	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 fiscal 2010, the services provided in this category included review of reserves disclosure as well as audit-related services in relation to our debt shelf prospectuses and Dividend Reinvestment Plan.
(3) Tax Fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2010, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns as well as assistance in respect of scientific research & experimental development claims.
(4) During fiscal 2010, 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.
(5) During fiscal 2009, no fees were billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP. Prior to the Arrangement, all fees had been billed to Encana.

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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, 2010, there were approximately 753 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 our 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 our assets in the event of any liquidation, dissolution or winding up of 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 each such class of shares as a return of capital in the event of liquidation, dissolution or winding up or any o ther distribution of our assets among our shareholders for the purpose of winding up our affairs would exceed $500 million.

Shareholder Rights Plan

We have a Shareholder Rights Plan that was adopted in 2009 to ensure, to the extent possible, that all our shareholders are treated fairly in connection with any take-over bid for Cenovus. The Shareholder Rights Plan creates a right that attaches to each issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited take-over bid, whereby a person acquires or attempts to acquire 20 percent or more of our Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquiror, from and after the separation time (unless delayed by our Board) and before certain expiration times, to acquire Common Shares at 50 percent of the market price at the time of exercise. The Shareholder Rights Plan must be reconfirmed by our shareholde rs at every third annual shareholder meeting, commencing in 2012.

Dividend Reinvestment Plan

During 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. The options vest over three years with 30 percent vesting after each of the first and second anniversary of the grant date and the remaining 40 percent vesting after the third anniversary. Options granted prior to February 17, 2010 expire after five years; options granted on or after February 17, 2010 expire after seven years. Each option has an associated tandem stock appreciation right which gives employees 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.

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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, 2010:

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")

Senior unsecured Long-Term Rating	BBB+/Stable	Baa2/Stable	A(low)/Stable
Commercial Paper Short-Term Rating	A-1(Low)/Stable	P-2/Stable	R-1(low)/Stable

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

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB+ by S&P is within the fourth highest of ten 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 financia l 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 (lowe st 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 ten 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 ten cate gories 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. Overall strength is not as favorable as higher rating categories, may be vulnerable to future events, but qualifying negative factors are considered manageable.

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DIVIDENDS

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

A first quarter dividend of $0.20 per share was declared payable on March 31, 2011 to holders of Common Shares of record as of March 15, 2011. In each of the four quarters in 2010, Cenovus paid a dividend of $0.20 per share ($0.80 per share annually). In the fourth quarter of 2009, Cenovus paid a dividend of US$0.20 per share.

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 2010.

2010	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	($ per share)			(millions)	(US$ per share)			(millions)
January	27.84	24.52	24.71	51.2	26.79	22.96	23.15	24.9
February	27.67	24.26	25.70	45.8	26.58	22.87	24.50	18.4
March	27.16	24.93	26.53	51.4	26.68	24.21	26.21	12.8
April	30.63	26.75	29.87	59.6	30.66	26.49	29.30	17.8
May	30.44	25.83	29.06	50.3	30.10	23.84	26.94	26.2
June	30.49	26.76	27.40	58.5	30.00	25.26	25.79	29.6
July	31.00	26.75	28.95	40.9	30.12	25.09	28.20	20.2
August	29.56	26.19	28.69	44.1	29.17	24.61	26.91	19.9
September	30.19	27.60	29.59	46.4	29.22	26.66	28.77	16.6
October	30.62	28.31	28.38	31.5	30.41	27.78	27.82	15.2
November	30.34	28.50	29.53	31.1	30.23	28.00	28.77	19.5
December	33.40	29.76	33.28	32.7	33.37	29.25	33.24	23.3

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RISK FACTORS

We have identified risks in three principal categories: financial, operational and regulatory. We believe that effectively managing risk is a competitive necessity and an integral part of creating shareholder value. We are continually working to mitigate the impact of potential risks to our business. Our approach to risk management includes an annual review and identification of principal risks, an analysis of the severity and likelihood of each principal risk, an evaluation of the effectiveness of the current mitigation and further mitigation or treatment of risks. We continuously monitor our risk profile as well as industry best practices.

Financial Risks

Financial risks include, but are not limited to, volatile financial markets, availability of credit and access to sufficient liquidity, fluctuations in commodity prices and foreign exchange and interest rates and risks related to our hedging activities. Some of these risks have intensified in recent years due to challenging market conditions caused by the global recession. These conditions 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, the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability, the supply of crude oil, 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 refi ned 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 US dollars, are stated in Canadian dollars.

Our financial performance is dependant on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. For example, our natural gas is predominately produced, processed and sold in Alberta at prices discounted to the Nymex natural gas price. This discount is influenced by regional supply and demand factors, including weather and the availability and the cost of export pipeline capacity. Fluctuations in this discount further compound the volatility in the underlying commodity price. Future price differentials are uncertain and increases in natural gas differentials have a negative impact on our business.

Of particular importance are the price differentials between our light/medium oil, heavy oil and bitumen, predominately produced in Western Canada, compared to the quoted Nymex WTI price. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as pipeline transportation interruptions and the quality of the oil produced. For example, market prices for heavy oil are lower than market indices for light and medium grades of oil, due principally to the lower value of the product yield and the higher transportation and refining costs required to upgrade heavy oil to an equivalent market standard. Bitumen prices are lower than heavy oil prices due to the cost of adding diluent to create a blended product with an acceptable viscosity for efficient transportation to market. Any shortf all in the supply of diluent may cause its cost to increase thereby increasing our cost to transport bitumen to market which would correspondingly increase our transportation and blending costs. The market price for this blended product is influenced by regional supply and demand factors, including the availability and price of diluent and the availability and cost of export pipeline capacity. The markets for heavy oil and blended bitumen products are more limited than for light and medium grades, making them more susceptible to supply and demand changes. Future price differentials are uncertain and increases in heavy oil differentials could have a negative impact on our business.

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The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices for 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, the costs of crude oil and other factors including 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 have a negative impact on our business.

Fluctuations in the price of these commodities, associated price differentials and refining margins may impact our ability to meet guidance targets, fund growth projects, maintain our dividend program and also may affect our operations, the value and amount of our proved reserves, the value of our refining assets and the amount of our borrowings. Any substantial or extended decline in these commodity prices could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or could result in unutilized long-term transportation commitments and low utilization levels at the refineries, all of which could have a material adverse effect on our business, financial conditions, results of operations and cash flow.

We reduce exposure to commodity price volatility through an integrated business strategy whereby a portion of operating supplies and feedstock is provided from internal operations. For example, the cost of natural gas consumed in heavy oil operations is offset with revenue from natural gas production thereby reducing our exposure to gas price volatility. There are no assurances that we will be able to maintain natural gas production to keep pace with growing internal natural gas demands.

We conduct an annual assessment of the carrying value of our assets in accordance with Canadian generally accepted accounting principles. If crude oil and natural gas prices decline or remain at low levels for an extended period of time, the carrying value of our assets could be subject to financial downward revisions and our earnings could be adversely affected.

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. One of the objectives within this policy is to protect a portion of our subsequent years' estimated cash flows.

We also use derivative instruments in various operational markets to optimize our supply or production chain. For example we may hedge the forward price of diluent purchased to transport bitumen by pipeline or hedge the price of physical crude acquired to balance pipeline operations.

We monitor our exposure to fluctuations in interest rates and foreign exchange rates. 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 priced in Canadian dollars to partially mitigate our net exposure to Canadian dollar operating costs.

We mitigate the risks inherent in using derivative instruments through ongoing and thorough investigation of counterparties and use this analysis to set appropriate volume, term and credit limits. The terms of our various hedging agreements, if any, 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 or if counterparties are unable to fulfill their obligations.

Under Canadian generally accepted accounting principles, derivative instruments that do not qualify as hedges, or are not designated as hedges, are marked-to-market with changes in fair value recognized in current period net earnings. The utilization of derivative financial instruments may therefore introduce significant volatility into our reported net earnings.

Credit and Liquidity

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. This could have an adverse effect on us, as our ability to make future capital expenditures and to finance our capital and operating commitments is dependent on certain factors including, but not limited to, access to the debt and equity markets, interest in investments in the energy industry generally and interest in our securities in particular.

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In September 2009, we issued US$3.5 billion in debt securities, substantially all of which were exchanged in June 2010 for debt securities registered under the Securities Act of 1933 with the same terms and conditions as the original issued securities. On September 15, 2014, the first tranche of the debt matures in the amount of US$800 million. We have a $2.5 billion committed credit facility, with a maturity of November 30, 2014, of which the entire amount was available at December 31, 2010 to meet operating and capital requirements. Despite the current state of our liquidity, an inability to access the credit markets or a sustained downturn in the prices of crude oil, natural gas or refined products or significant unanticipated expenses related to development or maintenance of our existing properties could seriously impact our liquidity and possibly impact our debt ratings should we seek additional capital. We are also required to comply with financial and operating covenants under our credit facility 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 growth plans and maintain existing properties may be impaired and our business, financial condition, results of operations and cash flow may be materially adversely affected as a result.

Foreign Exchange Rates

Foreign exchange rates will 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 outside of the U.S. are denominated in Canadian dollars and our Consolidated Financial Statements are reported in Canadian dollars.

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar creates uncertainty and impacts our capital expenditures and expenses. To the extent such fluctuations are unfavourable, it may have a material adverse effect on our business, financial condition, results of operations and cash flow. Our exposure to U.S. exchange rates is partially offset by our U.S. dollar obligations, such as interest costs on our U.S. dollar denominated debt. Additionally, when our U.S. dollar denominated notes mature, we may have exposure to U.S. dollar exchange rates on the principal repayment of the notes. Such a repayment of U.S. dollar denominated debt partially hedges us against the currency risk of U.S. dollar denominated revenues.

Interest Rates

Our credit facilities and commercial paper are exposed to floating interest rates which can impact our financial results, in particular our net interest expense. In addition, we are exposed to interest rate risk 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 royalties that we pay on our oil sands properties are 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 could 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 or incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects us, our operations or our future expansion plans.

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.

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.

Any indemnification claim against us pursuant to the provisions of the Arrangement Agreement or Separation Agreement could have a material adverse effect on our business, financial condition, results of operations and cash flow.

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 common risks affecting the oil and gas industry. Our operational risks include, but are not limited to, uncertainty of reserves and resources estimates, operational hazards, pipeline transportation 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.

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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, 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 such estimates and such variances could 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 conditions, 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 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. For additional information on resources and their associated c ontingencies, see "Contingent and Prospective Resources" in this AIF.

Operational and Safety Considerations

The operation of our properties is subject to the customary hazards of recovering, transporting and processing hydrocarbons, including but not limited to, blowouts, fires, explosions, gaseous leaks, migration of harmful substances, oil spills, corrosion, 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.

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Our refining and marketing business is subject to all of the risks normally 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, 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. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Pipeline Transportation Interruptions

Our production is transported through various pipelines and our refineries are reliant on various pipelines to receive feedstock. Disruptions in pipeline service could adversely affect our crude oil and natural gas sales, refining operations and our cash flow. Interruptions 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 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 constrain ts 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 feedstock with negative implications on sales and cash from operating activities.

We reduce the exposure to these risks by allocating deliveries to multiple customers using multiple pipelines. We also maintain knowledge of the infrastructure operational issues and influence expansion proposals through industry organizations in order to assess and respond to delivery risks. We have limited capacity to mitigate these risks in respect of our refining operations.

Phased 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, 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. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business , financial condition, results of operations and cash flow.

Partner Risks

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 also 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 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 or our ability to obtain or maintain necessary licenses o r approvals or affect the timing of undertaking various activities.

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Other companies operate a portion of the assets in which we have interests. We will have limited ability to exercise influence over operations of these assets or their associated costs. Our dependence on the operator and other working interest owners for these properties and assets and our limited ability to influence operations and associated costs could materially adversely affect our financial performance, the results of our operations and our cashflow. 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 labour and materials. Depending on the levels of future demand, increased supplies could have a negative impact on prices, which in turn may impact our business, financial condition, results of operations and cash flow.

Technology

Current SAGD technologies for the recovery of heavy oil are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations and cash flow. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Third-Party Claims

From time to time, we may be the subject of litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate and 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.

Key Personnel

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

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Information Systems

We depend on a variety of information systems to operate effectively. A failure of any one of the information systems or a failure among the 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, 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 ter ms could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on our business, financial conditions, results of operations and cash flow.

Environmental Regulations

All phases of the crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, “environmental regulations”). Environmental regulations require that wells, facility sites, refineries and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental 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 modif ication of existing regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas, increase our costs and have a material adverse effect on our business, financial condition, results of operations and cash flow.

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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 operation s. Consequently, no assurances can be given that the effect of future federal climate change regulations will not be significant to us, which could result in a material adverse effect on our business, financial condition, results or operations and cash flow.

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 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.

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. For example, the United States federal government and certain U.S. states (California in particular), have passed, or are considering legislation, which in some circumstances takes into account the GHG emissions used to produce fuel, which may negatively impact marketing of our refined products and ultimately have a material impact on the cost of refined petroleum products.

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, which is to be implemented under the Alberta Land Stewardship Act ("ALSA"), 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. The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while consider ing social and economic impacts.

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In August 2010, the Lower Athabasca Regional Advisory Council ("RAC") provided its vision document to the Government of Alberta regarding the LARP. Cenovus is actively participating in the feedback process as a stakeholder with significant activities in the region and will continue to monitor developments going forward. The Government of Alberta is expected to respond to the RAC advice with its own LARP recommendations. It is possible that the RAC vision, if adopted in its current form by the Government of Alberta, may negatively impact Cenovus's access to or our ability to conduct operations on certain resource properties or limit the pace of development due to environmental limits and thresholds.

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 expected to begin implementing those recommendations in the first half of 2011.

Alberta Environment Water Licences

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

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

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, 2010 which is accessible on our SEDAR profile at www.sedar.com and on EDGAR at www.sec.gov.

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.

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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 annual information form, has or has had any material interest, direct or indirect, in any past transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect us.

MATERIAL CONTRACTS

During the year ended December 31, 2010, 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 – Arrangement Related Risk".

INTERESTS OF EXPERTS

Our independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 18, 2011 in respect of our consolidated financial statements as at December 31, 2010 and December 31, 2009 and for each of the years in the three year period ended December 31, 2010 and Cenovus's internal control over financial reporting as at December 31, 2010. 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. Prior to November 30, 2009, PricewaterhouseCoopers LLP were the auditors of Encana and, on November 30, 2009, were appointed auditors of Cenovus.

Information relating to reserves and resources in this annual information form 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 7010
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Canada

In the United States:

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey 07310
U.S.A.

Tel: 1-866-332-8898
Website: www.cibcmellon.com/investorinquiry

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ADDITIONAL INFORMATION

General

Additional information relating to us 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 information, 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 information circular for the 2011 annual meeting of shareholders, which involves the election of directors.

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 www.cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

Additional financial information is contained in our audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2010.

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.

Unless otherwise indicated, all financial information included in this annual information form is determined using Canadian GAAP, which differs from U.S. GAAP in certain material respects, and thus may not be comparable to financial statements and financial information of U.S. companies. The notes to our audited consolidated financial statements for the year ended December 31, 2010 contain a discussion of the principal differences between the financial results calculated under Canadian GAAP and under U.S. GAAP.

Certain historical information contained in this annual information form 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 such 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.

Promoter

Under applicable Canadian securities laws, Encana was considered a promoter of Cenovus in 2009 because it took the initiative in our founding for the purpose of implementing the Arrangement. As consideration for the acquisition of our assets pursuant to the Arrangement, we issued a demand note payable to Encana in the aggregate amount of US$3.5 billion. The value was determined through the equitable allocation of the pre-Arrangement value of Encana's debt as determined by, among other things, an assessment of assets and liabilities to be transferred to Cenovus pursuant to the Arrangement, an allocation of then current income tax payable, an allocation of transaction costs related to the Arrangement and appropriate capital structures. The demand note was repaid in full on the completion of the Arrangement. Subsequent to the completion of the Arrangement, Cenovus made an additional US$250 million pay ment to Encana to adjust the cash balances of both companies to the agreed upon amounts pursuant to the Separation Agreement. As of the date hereof, Encana does not beneficially own or control or direct, directly or indirectly, any Common Shares. Refer to "Risk Factors - Arrangement Related Risk" for additional information regarding certain ongoing commitments, including the Separation Agreement, between Encana and Cenovus. Additional information regarding the Arrangement is available in our annual information form for the year ended December 31, 2009, available at www.cenovus.com and on SEDAR at www.sedar.com.

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ABBREVIATIONS

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

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

In this annual information form, 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 one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

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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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010.

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 February 16, 2011	Canada	$21,724
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation January 26, 2011	Canada	$2,650
			$24,374

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

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

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

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

/s/ Harry Jung
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 17, 2011

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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, 2010, 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, on the recommendation of the Reserves Committee, 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 17, 2011

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APPENDIX C

AUDIT COMMITTEE MANDATE

I. PURPOSE

The Audit Committee (the "Committee") is appointed by the Board of Directors of Cenovus Energy Inc. ("Cenovus" or the "Corporation") to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- 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.
- Receive and review the reports of the Audit Committee of any subsidiary with public securities.
- Oversee and monitor the integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance.
- Oversee audits of the Corporation's financial statements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing department.
- Provide an avenue of communication among the external auditors, management, the internal auditing department, 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

Committee Member's Duties in addition to those of a Director

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board of Directors.

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 and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of generally accepted accounting principles and financial statements;

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- 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 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 fr om 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 Chairman shall be a non-voting member of the Committee. See "Quorum" for further details.

APPOINTMENT OF 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.

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

If the Chairman of the Committee is 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 Chairman of the Committee presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chairman 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*.

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

The Corporate Secretary or one of the Assistant Corporate Secretaries of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

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MEETINGS

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

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

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 Chairman or by a majority of the members of the Committee.

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

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.

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.

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, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Corporation's annual report or other public disclosure documentation.

Provide a 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 filed with the SEC.

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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 to include:

   (a) The annual financial statements and related footnotes 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) A review of the use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

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

   (e) Review of any significant changes required in the external auditors' audit plan.

   (f) A review of 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) A review of 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.

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

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 securities regulators or news releases related thereto (or provided to analysts or rating agencies) and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made).

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee 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 significant findings prepared by the external auditors and the internal auditing department together with management's responses.

8. 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.

Other Review Items

9. 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.

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

11. 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.

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

13. 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.

14. Ensure that the Corporation's presentations on net proved reserves have been reviewed with the Reserves Committee of the Board.

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

16. Review 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.

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17. 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 involv es management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

18. Meet on a periodic basis separately with management.

EXTERNAL AUDITORS

19. 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.

20. 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 Chairman of the Committee or by a majority of the members of the Committee.

21. 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 generally accepted 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.

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

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

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

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

23. 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 a uditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

24. Review and evaluate:

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    (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.

25. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 21 through 24, 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 its conclusions with respect to the external auditors to the Board.

26. Ensure 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.

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

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

29. 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 Department and Independence

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

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

32. Confirm and assure, annually, the independence of the internal audit department and the external auditors.

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Approval of Audit and Non-Audit Services

33. 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 Canadian federal and provincial legislation and regulations which are approved by the Committee prior to the completion of the audit).

34. 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.

35. If the pre-approvals contemplated in paragraphs 33 and 34 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.

36. 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 33 through 35. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

37. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 33 and 34, 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 of the Committee's responsibilities under the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

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

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

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

41. 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.

42. The Corporation shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (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.

43. Obtain assurance from the external auditors that disclosure to the Committee is not required pursuant to the provisions of the*Exchange Act* regarding the discovery of illegal acts by the external auditors.

44. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

45. The Committee's performance shall be evaluated annually by the Nominating and Corporate Governance Committee of the Board of Directors.

46. Perform such other functions as required by law, the Corporation's mandate or bylaws, or the Board of Directors.

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

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Cenovus Energy Inc.

Management's Discussion and Analysis
For the Year Ended December 31, 2010
(Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated February 18, 2011, should be read with our audited Consolidated Financial Statements for the year ended December 31, 2010 ("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 document, see the Advisory at the end of this MD&A.

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 is indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and reserve volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's presentation.

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INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

Cenovus is a Canadian oil company headquartered in Calgary, Alberta, with a market capitalization of approximately $25 billion on December 31, 2010. In 2010, we had total crude oil, natural gas and NGL production in excess of 250,000 barrels of oil equivalent per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties 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 Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewa n. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S.A., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel to reduce volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase production, predominantly from Foster Creek and Christina Lake as well as Pelican Lake and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach and our conventional crude oil and natural gas production base is expected to generate reliable production and cash flows which will enable further development of our oil sands 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 continuous innovation. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to m inimize surface land disturbance.

Our future lies in developing the land position that we hold in the Athabasca region in northeast Alberta. In addition to our Foster Creek and Christina Lake oil sands projects, we currently have three emerging projects in this area:

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

[1] Approximate ownership interest

At our Narrows Lake property, located within the Christina Lake Region, we have submitted a joint application and environmental impact assessment (“EIA”). This project is expected to begin producing in 2016, and is expected to have a gross production capacity of 130,000 bbls/d. At our Grand Rapids property, which is located within the Greater Pelican Region, a pilot project is underway. If this pilot is determined to be successful, we expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 bbls/d. Our Telephone Lake property is located within the Borealis Region. We have submitted a regulatory application for the development of this property, including the construction of a facility with gross production capacity of 35,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands, most of which is undeveloped. Our 10 year business plan is to grow our net oil sands production from approximately 60,000 bbls/d in 2010 to 300,000 bbls/d by the end of 2019. Growth is expected to be primarily internally funded through cash flow generated from our established crude oil and natural gas production base where we also have opportunities to add production through new technologies. Our natural gas production provides 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. A key miles tone in this regard is the planned 2011 coker startup of the Coker and Refinery Expansion (“CORE”) project at the Wood River refinery. We also 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 dividends to deliver strong total shareholder return over the long term.

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OUR BUSINESS STRUCTURE

Our operating and reportable segments are as follows:

- **Upstream**, which includes Cenovus's development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
  - **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 oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips and operated by Cenovus.
  - **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.
- **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 or losses recorded on derivative financial instruments 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 operating and reportable segments shown above were changed from those presented in prior periods to better align with our long range business plan. All prior periods have been restated to reflect this presentation.

2009 Financial Information

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.

The results for the year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent the Company's operations, cash flow, and financial position as a stand-alone entity. The results for the periods prior to the Arrangement, being January 1 to November 30, 2009 and January 1 to December 31, 2008 have been prepared on a "carve-out" accounting basis whereby results 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. Further information on the carve-out assumptions can be found in the notes to the Consolidated Financial Statements.

OVERVIEW OF 2010

2010 marked our first full year operating as an independent company, and we delivered very strong performance overall. Excellent operating performance reflected strong oil sands production growth, with very good operating and capital cost controls to maintain our position as a low cost producer. Despite diminished realized natural gas prices, which resulted from the large oversupply of natural gas markets and crude oil pipeline disruptions, both of which impacted our operating cash flows, we achieved our 2010 cash flow guidance and generated net earnings of $993 million which exceeded 2009 by 21 percent. In addition, managing our business with a continual focus on value creation, cost control and updated credit facilities resulted in Cenovus having an even stronger financial position at the end of 2010 than at the start of the year.

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Specific highlights for 2010 include:

- Substantial growth in our bitumen proved reserves (year-over-year increase of 288 MMbbls), resulting in very low finding and development costs;
- Production from our Foster Creek and Christina Lake oil sands projects increasing by 33 percent;
- Receiving regulatory approval for Foster Creek expansion phases F, G and H;
- Capital spending on the Foster Creek and Christina Lake expansions increasing significantly, consistent with our strategy to move these projects forward; and
- Our Conventional crude oil and natural gas business generating more than $1.2 billion in operating cash flow in excess of the related capital spent to fund the development of our oil sands projects.

Additional operating and financial highlights for 2010 compared to 2009 include:

- Total capital spending being relatively unchanged year over year, however, spending on our oil sands projects increased 38 percent to $867 million while spending on our refineries decreased 37 percent to $655 million. In our Conventional upstream business, our spending focus on oil increased to 68 percent of spending ($358 million) in 2010 compared to 48 percent ($223 million) in 2009;
- Proceeds from the divestiture of property, plant and equipment totaled $307 million (2009 - $222 million);
- Net revenues increasing 13 percent mainly due to improved crude oil and refined product prices despite pipeline transportation disruptions of crude oil from Alberta to mid-west U.S. refineries in the second half of 2010 and higher royalties as a result of Foster Creek achieving payout status for royalty purposes;
- As expected, based on realized natural gas prices declining 34 percent and natural gas volumes declining 12 percent (including the impact of divestitures) we had a decrease in our Upstream operating cash flow of $921 million. The lower natural gas prices and lower operating cash flow from Refining and Marketing resulted in decreases to our cash flow of $430 million and operating earnings of $728 million. The natural gas decreases were partially offset by higher crude oil volumes and realized prices;
- Operating cash flow from Refining and Marketing decreasing by $293 million mainly due to planned turnarounds at both refineries, higher average crude costs and refinery optimization activities due primarily to weaker diesel and gasoline prices primarily in the first half of 2010. Partially offsetting these decreases were lower operating expenses and a strengthening of the Canadian dollar;
- Net earnings increasing $175 million mainly due to unrealized foreign exchange gains, unrealized mark-to-market hedging gains and lower income taxes, partially offset by lower operating cash flows;
- Our debt metrics improving with debt to capitalization decreasing to 26 percent and debt to adjusted EBITDA being 1.2x; and
- Declaring and paying dividends of $601 million ($0.20 per share per quarter) in 2010 compared to US$150 million in 2009 paid in connection with the Arrangement.

Reserves and Resources

The receipt of Alberta Energy Resources Conservation Board ("ERCB") regulatory approval for expansion phases F, G and H at Foster Creek, including expansion of the development area, combined with an overall increased recovery factor in the area, has resulted in a significant increase to our proved bitumen reserves in 2010. In 2010, we also issued two news releases highlighting detailed information related to our bitumen initially-in-place, contingent resources and prospective resources, which enable investors to more fully understand our inventory of oil sands assets.

We also provided further information about our resources and development plans at our Investor Day presentations in June 2010 and at the end of 2010 the estimates of bitumen contingent and prospective resources were updated. Our best estimate bitumen contingent resources at December 31, 2010 were approximately 6.1 billion barrels and our best estimate bitumen prospective resources were approximately 12.3 billion barrels.

Foster Creek
Our Foster Creek property achieved project payout for royalty purposes in February 2010. Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. As a result, Foster Creek's royalties increased from $19 million and an effective royalty rate of 2.7 percent in 2009 to $165 million and an effective royalty rate of 16.2 percent in 2010, which includes pre-payout royalties for one month.

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As noted above, we received regulatory approval from the ERCB for the next three expansion phases at Foster Creek, F, G and H. When all three phases are complete, Foster Creek's gross production capacity is expected to increase from the current 120,000 bbls/d to 210,000 bbls/d. The next step for these expansions is to receive final partner approval, which is expected in 2011. Engineering and preliminary ground work on phase F is already underway. First production for phase F is expected to be accelerated by 12 months to 2014 compared to our original plan. Production from the other two phases is expected in 2016-2017.

Christina Lake
The construction of the Christina Lake expansion is progressing with phases C and D each expected to add an additional 40,000 bbls/d of gross production capacity. Start up of phase C is expected to begin with steam injection in the second quarter of 2011 and production commencing in the second half of 2011. Production from phase D has been advanced from its original planned start by approximately six months and is now targeted to begin in 2013. These expansion phases are expected to bring Christina Lake's gross production capacity to 98,000 bbls/d in 2013.

New Resource Plays
We have announced our intention to move ahead with the development of Narrows Lake, which may use a combination of SAGD and Solvent Aided Process ("SAP") to recover the bitumen. SAP is a technological improvement applied to our SAGD operations that helps maximize the amount of bitumen recovered and requires less steam and water usage. SAP takes the benefit of injecting steam in the SAGD process and combines it with solvents, such as butane, to help bring the bitumen to the surface. In the first quarter of 2010, we initiated the regulatory approval process 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.

In 2010, we received approval from the ERCB and Alberta Environment to begin a pilot project at our Grand Rapids project. The drilling of a SAGD well pair and construction of associated facilities is complete and steam injection commenced in December 2010.

As part of our efforts to progress these emerging projects, in 2010, we significantly increased our spending to $124 million in new resource play areas including the drilling of over 150 gross stratigraphic wells and commencing our Grand Rapids pilot project. In addition, we continued our research and development efforts that we expect will continue to reduce our land footprint, water use and air emissions intensity.

Refining CORE Project
At the end of 2010, the CORE project progressed to approximately 91 percent complete from 71 percent at the beginning of the year. Commissioning of several of the process units has been completed with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

Net Capital Investment
Unusual weather patterns across our operating areas throughout the year, including a very wet summer, restricted access to our properties and with continued low commodity prices we chose to reduce spending, which has resulted in our upstream capital investment program being lower than originally planned in some of our operating areas. Although upstream capital spending is lower than expected, production levels have remained at expected levels. Our refining capital spending was also lower than expected as unusually high water levels on the Mississippi River delayed deliveries of various CORE modules, deferring some 2010 spending to 2011. As part of our ongoing portfolio management strategy, we divested of certain non-core oil and gas assets for proceeds of $221 million, which reduced our 2010 crude oil and NGLs production by approximately 975 bbls/d (one percent) and natural gas production by approximate ly 33 MMcf/d (four percent). In total, our 2010 property, plant and equipment divestitures resulted in proceeds of $307 million.

Net Revenues
During the second half of 2010, pipeline disruptions and apportionment challenges restricted the access of Alberta crude oil to U.S. markets. As a result, there were higher inventory levels of WCS and a widening of the WTI-WCS price differential in the second half of 2010.

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The widened WTI-WCS differential had a negative impact on our upstream revenue, however our refining operations benefitted somewhat due to a lower cost for purchased product. While the effects of pipeline apportionment did not significantly affect our production, it did result in lower sales volumes in the second half of 2010 as we added volumes to storage at the end of 2010.

With respect to commodity prices, our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows and therefore commodity price hedging activity continues to be an important element of our business model. This activity reflects our objective of locking in prices on a portion of our natural gas and crude oil production such that we protect a significant portion of the subsequent years' cash flows. Realized after-tax hedging gains of $199 million during 2010 (2009 – gains of $804 million) reflect the benefits of locking in commodity prices in excess of the current period benchmark

prices. These realized hedging gains are significantly less than those of 2009 since they effectively reflect the significant over supply and deterioration of natural gas markets and prices over the last two years. Our hedging strategy continues to be sound and allowed us to put in place natural gas hedges for 2010 at approximately $6.00 per Mcf as compared to hedges for 2009 put in place at approximately $9.00 per Mcf when future prices were higher in 2008. For more information on our realized hedging prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

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 select market benchmark prices and foreign exchange rates to assist in understanding our financial results.

Selected Benchmark Prices [1]

	2010	**Q4**	**Q3**	**Q2**	**Q1**	2009	Q4	Q3	Q2	Q1	2008
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate											
Average	**79.61**	**85.24**	**76.21**	**78.05**	**78.88**	62.09	76.13	68.24	59.79	43.31	99.75
End of period spot price	**91.38**	**91.38**	**79.97**	**75.63**	**83.45**	79.36	79.36	70.46	69.82	49.64	44.60
Western Canada Select											
Average	**65.38**	**67.12**	**60.56**	**63.96**	**69.84**	52.43	64.01	58.06	52.37	34.38	79.70
End of period spot price	**72.87**	**72.87**	**64.97**	**61.38**	**70.25**	71.84	71.84	59.76	59.12	42.69	35.40
Average Price – Differential WTI-WCS	**14.23**	**18.12**	**15.65**	**14.09**	**9.04**	9.66	12.12	10.18	7.42	8.93	20.05
Condensate (C5 @ Edmonton)	**81.91**	**85.24**	**74.53**	**82.87**	**84.98**	61.35	74.42	65.76	58.07	46.26	106.22
Average Price - Differential WTI-Condensate (premium)/discount	**(2.30)**	**-**	**1.68**	**(4.82)**	**(6.10)**	0.74	1.71	2.48	1.72	(2.95)	(6.47)
Refining Margin 3-2-1 Crack Spread [2] *(US$/bbl)*											
Chicago	**9.33**	**9.25**	**10.34**	**11.60**	**6.11**	8.54	5.00	8.48	10.95	9.75	11.22
Midwest Combined (Group 3)	**9.48**	**9.12**	**10.60**	**11.38**	**6.82**	8.09	5.52	8.06	9.16	9.62	11.03
Natural Gas Prices											
AECO *($/GJ)*	**3.91**	**3.39**	**3.52**	**3.66**	**5.08**	3.92	4.01	2.87	3.47	5.34	7.71
NYMEX *(US$/MMBtu)*	**4.39**	**3.80**	**4.38**	**4.09**	**5.30**	3.99	4.17	3.39	3.50	4.89	9.04
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.40**	**0.28**	**0.78**	**0.32**	**0.19**	0.40	0.19	0.67	0.39	0.35	1.23
Foreign Exchange											
Average US/Canadian dollar exchange rate	**0.971**	**0.987**	**0.962**	**0.973**	**0.961**	0.876	0.947	0.911	0.857	0.803	0.938

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. For our realized sales prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

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The global economic recovery that began in the second half of 2009 continued throughout 2010 resulting in increased crude oil demand, mainly from China, other Asian countries and the United States, and was reflected in higher WTI benchmark prices. The closing price of WTI at the end of 2010 increased 15 percent from the 2009 closing price and was more than double the 2008 closing price. While crude oil demand increased compared to 2009 and global production levels from both OPEC and non-OPEC countries has increased, significant spare OPEC production capacity still remained at the end of 2010. Further increases in OPEC production could result in a lowering of crude oil prices. WTI is an important benchmark as it is also used as the basis for determining royalties for a number of our crude oil properties.

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. The widening of the WTI-WCS differential in 2010 was partially the result of pipeline transportation disruptions of crude oil from Alberta to mid-west U.S. refineries as well as refinery downtime in certain regions of the U.S. in the second half of 2010. While overall the price of WCS increased in 2010 compared to 2009, pipeline disruptions resulted in increased WCS inventory which negatively impacted its market price. At the same time, the price of WTI increased substantially in 2010 resulting in the differential widening to as much as US$31.00 per bbl during the year. The end of 2010 saw the differential narrowing to approximately US$18.51 per bbl.

Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The WTI-condensate differential is the benchmark price of condensate relative to the price of WTI. As purchased condensate is sold as part of the crude oil blend, the cost of condensate purchases impacts both our revenues and transportation and blending costs. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem.

Benchmark refining margin crack spreads for 2010 improved from 2009 due, in part, to an increase in consumer demand for refined products partly due to the improved economy in the U.S., resulting in increased gasoline and distillate consumption. However, most of the improvement can be attributed to weaker WTI prices relative to other global crude and product prices as a result of pipeline congestion in inland U.S. markets.

In 2010, benchmark NYMEX natural gas prices showed marginal improvement primarily due to increased consumption for electric power generation due to record summer heat as well as natural gas prices becoming more economical than certain coal as a fuel source for power generation. 2010 also saw natural gas demand increase for use in the industrial sector of the U.S. While NYMEX natural gas prices were higher in 2010 compared to 2009, throughout 2010 the NYMEX price has been generally on a downward trend. The main cause of the declining natural gas prices in 2010 was natural gas supply. Industry wide natural gas drilling activity, primarily from shale gas, remained strong in 2010 which resulted in higher levels of North American natural gas production as well as volumes in storage increasing to record high levels despite declining market prices.

During 2010, the Canadian dollar strengthened relative to the U.S. dollar, primarily since the economic recovery in Canada moved at a greater pace than in the U.S. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sale 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 this segment's reported results.

Our risk mitigation strategy has helped reduce our exposure to commodity price volatility. Realized hedging gains, after-tax, in 2010 were $199 million (2009 – gains of $804 million; 2008 – losses of $196 million). Further information regarding our hedging program can be found in the notes to the Consolidated Financial Statements.

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FINANCIAL INFORMATION

In our financial reporting to shareholders for the year ended December 31, 2009, we used U.S. dollars as our reporting currency and reported production on an after royalties basis. Effective January 1, 2010, we changed our reporting currency to Canadian dollars and our reporting of production to a before royalties basis. This change in reporting currency and protocol was made to better reflect our business, and allows for increased comparability to our peers. With the change in reporting currency and protocol, all comparative information has been restated from U.S. dollars to Canadian dollars and production from after royalties to before royalties.

SELECTED CONSOLIDATED FINANCIAL RESULTS

(millions of dollars, except per share amounts)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Net Revenues	**12,973**	**13%**	11,517	-34%	17,570
Operating Cash Flow [1]	**2,975**	**-29%**	4,189	7%	3,933
Cash Flow [1]	**2,415**	**-15%**	2,845	-9%	3,115
- per share – diluted [2]	**3.21**		3.79		4.14
Operating Earnings [1]	**794**	**-48%**	1,522	-6%	1,620
- per share – diluted [2]	**1.06**		2.03		2.15
Net Earnings	**993**	**21%**	818	-68%	2,526
- per share – basic [2]	**1.32**		1.09		3.37
- per share – diluted [2]	**1.32**		1.09		3.36
Total Assets	**22,095**	**2%**	21,755	-4%	22,614
Total Long-Term Debt	**3,432**	**-6%**	3,656	-2%	3,719
Other Long-Term Obligations	**6,156**	**-5%**	6,507	-11%	7,308
Capital Investment	**2,122**	**-2%**	2,162	-2%	2,204
Free Cash Flow [1]	**293**	**-57%**	683	-25%	911
Cash Dividends [3]	**601**		159		n/a
- per share [3]	**0.80**		US$0.20		n/a

(1) Non-GAAP measure defined within this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.
(3) The 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

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NET REVENUES VARIANCE

(millions of dollars)			
Net Revenues for the Year Ended December 31, 2009			$ 11,517
Increase (decrease) due to:			
Upstream	Prices	$ 238	
	Realized hedging	(882)	
	Volume	(43)	
	Royalties	(176)	
	Condensate and Other [1]	299	
			(564)
Refining and Marketing			1,306
Corporate and Eliminations	Unrealized hedging	$ 728	
	Other	(14)	
			714
Net Revenues for the Year Ended December 31, 2010			**$ 12,973**

(1) Revenue dollars reported include the value of condensate sold as bitumen or heavy oil blend. Condensate costs are recorded in transportation and blending expense.

The increase in net revenues for 2010 is comprised of two main items.

Our Upstream net revenues decreased in 2010 primarily due to the decrease in our realized natural gas prices and natural gas production, as well as higher crude oil royalties. Partially offsetting these decreases were increases in the realized price and production of crude oil as well as increased prices and volumes of condensate blended with heavy oil consistent with increases in our production.

Our Refining and Marketing net revenues for 2010 increased primarily because of higher refined product prices and higher prices and volumes related to operational third party sales undertaken by the marketing group, partially offset by reduced refined products volumes from planned turnarounds, a power outage and refinery optimization activities. Also increasing net revenues in 2010, were unrealized hedging gains on natural gas.

Further information and explanations regarding our net revenues can be found in the Operating Segments and Corporate and Eliminations sections of this MD&A.

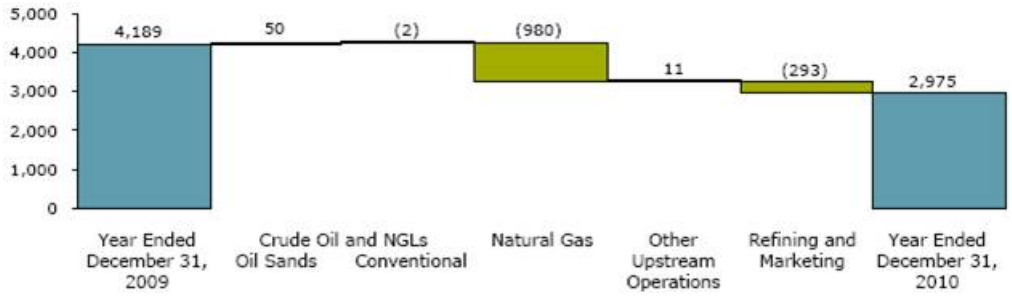
OPERATING CASH FLOW

(millions of dollars)	2010	2009	2008
Crude Oil and NGLs			
Oil Sands	**$ 1,052**	$ 1,002	$ 1,019
Conventional Crude Oil and NGLs	**751**	753	1,033
Natural Gas	**1,081**	2,061	2,227
Other Upstream Operations	**16**	5	13
	2,900	3,821	4,292
Refining and Marketing	**75**	368	(359)
Operating Cash Flow	**$ 2,975**	$ 4,189	$ 3,933

Operating cash flow is a non-GAAP measure defined as net revenues less production and mineral taxes, transportation and blending, operating and purchased product expenses. It 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.

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Operating cash flow includes realized hedging gains and losses but excludes unrealized hedging gains and losses which are included in the Corporate and Eliminations segment.



Operating cash flow decreased by $1,214 million in 2010 primarily because of a $980 million reduction related to natural gas as a result of a 34 percent decrease in realized prices along with lower production volumes. Crude Oil and NGLs operating cash flow increased $48 million in 2010 as higher production and realized prices were partially offset by higher operating expenses consistent with increased production and higher royalties, mainly due to Foster Creek achieving payout status for royalty purposes in 2010.

Operating cash flow for Refining and Marketing decreased $293 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds, a power outage and refinery optimization activities related to weaker diesel and gasoline prices primarily in the first half of 2010.

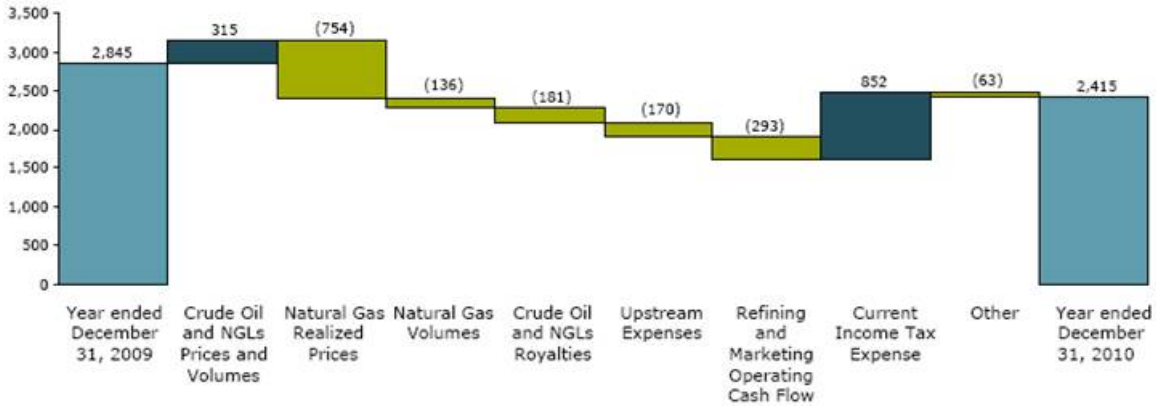
Details of the components that explain the decrease in operating cash flow can be found in the Operating Segments section of this MD&A.

CASH FLOW

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 the ability to finance capital programs and meet financial obligations.

(millions of dollars)	2010	2009	2008
Cash From Operating Activities	**$ 2,594**	$ 3,039	$ 3,225
(Add back) deduct:			
Net change in other assets and liabilities	**(55)**	(26)	(92)
Net change in non-cash working capital	**234**	220	202
Cash Flow	**$ 2,415**	$ 2,845	$ 3,115

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In 2010 our cash flow decreased $430 million from 2009 primarily due to:

- A 34 percent decrease in the average realized natural gas price to $5.16 per Mcf compared to $7.78 per Mcf;
- A decrease in operating cash flow from Refining and Marketing of $293 million mainly due to planned turnarounds at both refineries, higher crude costs and refinery optimization activities due primarily to weak diesel and gasoline prices in the first half of 2010. Partially offsetting these decreases to operating cash flow was a strengthening of the Canadian dollar;
- An increase in crude oil and NGLs royalties of $181 million primarily as a result of Foster Creek achieving project payout status for royalty purposes as well as higher WTI prices partially offset by a strengthened average Canadian dollar used for calculating royalties;
- Natural gas production in total declining 12 percent as a result of the divestiture of certain non-core properties, which made up four percent of the total annual decrease, as well as reduced capital expenditures;
- An increase in general and administrative and net interest expense of $75 million;
- Higher crude oil and NGLs operating expenses consistent with the increase in production; and
- Realized foreign exchange losses of $18 million in 2010 compared to gains of $23 million in 2009.

The decreases in our 2010 Cash Flow were partially offset by:

- A $852 million decrease in current income tax expense as a result of 2009 including acceleration of current income tax along with 2010 including the utilization of claims from tax pools that we received as a result of the Arrangement, as well as lower realized hedging gains in 2010;
- A seven percent increase in our average realized liquids price to $62.60 per bbl compared to $58.24 per bbl; and
- A six percent increase in our crude oil and NGLs production volumes.

In 2009, our cash flow decreased $270 million compared to 2008 as a result of:

- Current income tax expense increased $565 million primarily due to accelerated income tax as a result of the dissolution of a partnership as part of the Arrangement;
- A decrease in the realized average liquids selling price, including the impact of hedges, of $14.25 per bbl to $58.24 per bbl;
- Natural gas production declined 12 percent; and
- A decrease in the realized average natural gas price, including the impact of hedges, to $7.78 per Mcf compared to $7.93 per Mcf.

The 2009 Cash Flow decreases above were partially offset by:

- An improvement in our operating cash flow from Refining and Marketing of $727 million;
- A decrease in royalties of $260 million resulting from decreased commodity sales prices;
- An eight percent increase in our crude oil and NGLs production volumes; and
- Realized foreign exchange gains of $23 million in 2009 compared to losses of $9 million in 2008.

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OPERATING EARNINGS

(millions of dollars)	**2010**	2009	2008
Net Earnings	**$ 993**	$ 818	$ 2,526
(Add back) deduct:			
Unrealized mark-to-market accounting gains (losses), after-tax [1]	**34**	(494)	636
Non-operating foreign exchange gains (losses), after-tax [2]	**153**	(210)	270
Gain on bargain purchase, after-tax	**12**	-	-
Operating Earnings	**$ 794**	$ 1,522	$ 1,620

(1) The unrealized mark-to-market accounting 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 future 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 mark-to-market accounting gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange 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 items identified above that affected our cash flow and identified below that affected our net earnings also impacted our operating earnings.

The decline in operating earnings for 2010 is consistent with the decreases to our operating cash flow and cash flow, details of which can be found above, partially offset by a decrease in depreciation, depletion and amortization ("DD&A") expense.

NET EARNINGS VARIANCE

(millions of dollars)		
Net Earnings for the Year Ended December 31, 2009		$ 818
Increase (decrease) due to:		
Operating Segments		
Upstream net revenues	$ (564)	
Upstream expenses[1]	(357)	
Upstream operating cash flow		(921)
Refining and Marketing operating cash flow		(293)
Corporate and Eliminations		
Unrealized hedging gains (losses), net of tax		528
Unrealized foreign exchange gains (losses)		396
Expenses[2]		(142)
Depreciation, depletion and amortization		217
Income taxes, excluding income taxes on unrealized hedging gains (losses)		390
Net Earnings for the Year Ended December 31, 2010		**$ 993**

(1) Includes production and mineral tax, transportation and blending and operating expenses.
(2) Includes general and administrative, net interest, accretion of asset retirement obligations, realized foreign exchange (gains) losses, gain (loss) on divestiture of assets, other (income) loss, net and Corporate operating and purchased product expenses excluding unrealized hedging.

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In 2010, net earnings increased by $175 million. The items identified above that reduced our cash flow in 2010 also reduced our net earnings. Other significant factors that impacted 2010 net earnings include:

- Unrealized mark-to-market hedging gains, after-tax, of $34 million, compared to losses of $494 million, after-tax, in 2009;
- Unrealized foreign exchange gains of $69 million in 2010 compared to losses of $327 million in 2009;
- A decrease of $217 million in DD&A; and
- Future income tax expense, excluding the impact of the unrealized financial hedging gains, in 2010 of $76 million, compared to a recovery of $386 million in 2009.

In 2009, net earnings decreased $1,708 million compared to 2008. The items previously discussed that reduced our cash flow in 2009 also reduced our net earnings. Other significant factors that impacted our 2009 net earnings include:

- Unrealized mark-to-market hedging losses, after-tax, of $494 million compared to gains, after-tax of $636 million in 2008;
- DD&A expense increasing by $130 million;
- Unrealized foreign exchange losses of $327 million for 2009 compared to gains of $317 million in 2008; and
- Future income tax recovery, excluding the impact of the unrealized financial hedging gains and losses, of $386 million, compared to future income tax expense of $142 million in 2008.

Hedging Impact on Net Earnings

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Changes in mark-to-market gains or losses on these agreements affect our net earnings and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

(millions of dollars)	**2010**	2009	2008
Unrealized Mark-to-Market Hedging Gains (Losses), after-tax [1]	**$ 34**	$ (494)	$ 636
Realized Hedging Gains (Losses), after-tax [2]	**199**	804	(196)
Hedging Impacts in Net Earnings	**$ 233**	$ 310	$ 440

(1) Included in Corporate and Eliminations financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate and Eliminations section of this MD&A.
(2) Included in the Operating Segment financial results and included in operating cash flow and cash flow.

NET CAPITAL INVESTMENT

(millions of dollars)	**2010**	2009	2008
Upstream			
Oil Sands	**$ 867**	$ 629	$ 758
Conventional	**523**	466	848
	1,390	1,095	1,606
Refining and Marketing	**656**	1,033	539
Corporate	**76**	34	59
Capital Investment	**2,122**	2,162	2,204
Acquisitions	**86**	3	-
Divestitures	**(307)**	(222)	(48)
Net Capital Investment	**$ 1,901**	$ 1,943	$ 2,156

Upstream capital investment in 2010 was primarily focused on continued development of our oil sands projects and conventional oil properties, including the drilling of stratigraphic wells to support the next phases of our expansion activities. Refining and Marketing capital investment was primarily focused on the CORE project at the Wood River refinery.

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Capital investment was funded by cash flow. Further information regarding our capital investment can be found in the Operating Segments section of this MD&A.

Acquisitions and Divestitures

Our planned program to divest of non-core oil and gas assets in 2010 resulted in proceeds of $307 million. These divestitures included certain non-core conventional crude oil and natural gas producing properties as well as the sale of certain lands at the Narrows Lake property to the FCCL Partnership.

Our 2010 acquisitions included the purchase of an interest in three sections of undeveloped land at Narrows Lake as well as certain producing conventional oil properties. In the fourth quarter of 2010 under the terms of an agreement with an unrelated Canadian company, we acquired certain marine terminal facilities in Kitimat, British Columbia for $38 million.

FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of free cash flow, which is defined as cash flow in excess of capital investment, which excludes acquisitions and divestitures. Cash flow is a non-GAAP measure and is defined under the cash flow section of this MD&A.

(millions of dollars)	**2010**	2009	2008
Cash Flow	**$ 2,415**	$ 2,845	$ 3,115
Capital Investment	**2,122**	2,162	2,204
Free Cash Flow	**$ 293**	$ 683	$ 911

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

(bbls/d)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Oil Sands – Heavy Oil					
Foster Creek	**51,147**	**36%**	37,725	44%	26,220
Christina Lake	**7,898**	**18%**	6,698	57%	4,279
Pelican Lake	**22,966**	**-8%**	24,870	-9%	27,324
Senlac	**-**	**-**	3,057	-5%	3,223
Conventional Liquids					
Heavy Oil	**16,659**	**-7%**	17,888	-6%	19,062
Light and Medium Oil	**29,346**	**-3%**	30,394	-3%	31,492
NGLs[1]	**1,171**	**-3%**	1,206	-%	1,203
	129,187	**6%**	121,838	8%	112,803

(1) NGLs include condensate volumes.

Overall, our crude oil and NGLs production increased six percent in 2010. Increases in production volumes at Foster Creek and Christina Lake were partially offset by expected natural declines at our other properties. We also sold certain non-core Conventional properties in 2010 which decreased our total annual crude oil production by 975 bbls/d or one percent. In 2009, we also sold our Senlac property. Further detail on the changes in our production can be found in the Operating Segments section of this MD&A.

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Natural Gas Production Volumes

(MMcf/d)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Conventional	**694**	**-11%**	784	-9%	866
Oil Sands	**43**	**-19%**	53	-40%	88
	737	**-12%**	837	-12%	954

During 2009 and 2010, we chose to restrict capital spending on natural gas drilling, completion and tie-in activity in favour of increasing investment in crude

oil projects. In 2010, we divested of certain non-core natural gas properties which decreased annual production by approximately 33 MMcf/d, or four percent. Weather related delays experienced throughout 2010 also negatively impacted our natural gas production.

On a barrel of oil equivalent basis, excluding the divestitures, production remained consistent in 2010 compared to 2009. Further details on the changes in our production can be found in the Operating Segments section of this MD&A.

Operating Netbacks

	2010		2009		2008	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price [1]	**$ 62.96**	**$ 4.09**	$ 57.14	$ 4.15	$ 77.84	$ 8.17
Royalties	**9.33**	**0.07**	5.62	0.08	9.32	0.42
Production and mineral taxes	**0.62**	**0.02**	0.65	0.05	1.01	0.11
Transportation and blending [1]	**1.88**	**0.17**	1.60	0.15	1.62	0.24
Operating expenses	**11.78**	**0.96**	10.67	0.86	10.90	0.84
Netback excluding Realized Financial Hedging	**39.35**	**2.87**	38.60	3.01	54.99	6.56
Realized Financial Hedging Gains (Losses)	**(0.36)**	**1.07**	1.10	3.63	(5.35)	(0.24)
Netback including Realized Financial Hedging	**$ 38.99**	**$ 3.94**	$ 39.70	$ 6.64	$ 49.64	$ 6.32

(1) Operating netbacks for liquids exclude the value of condensate sold as bitumen blend and condensate costs recorded in transportation and blending expense.

In 2010, our average netback for liquids, excluding realized financial hedging, increased by $0.75 per bbl primarily due to an increase in prices partially offset by higher royalties and operating expenses. Our average netback for natural gas, excluding realized financial hedges, decreased by $0.14 per Mcf primarily as a result of lower sales prices and increased operating expenses per Mcf as natural gas production decreased while operating expenses were relatively consistent. Further discussions of operating results are contained in the Operating Segments section of this MD&A.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our price risk through a commodity price hedging program. Our strategy is to protect a significant portion of the subsequent years' cash flows through the use of various financial instruments. Further information regarding this program can be found in the notes to the Consolidated Financial Statements.

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OPERATING SEGMENTS

Our Upstream Segment has two reportable operations: Oil Sands and Conventional. Oil Sands consists of our producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, the new resource play assets such as our Narrows Lake, Grand Rapids and Telephone Lake properties as well as the Athabasca natural gas assets. Conventional includes the development and production of crude oil, natural gas and NGLs in western Canada. The Refining and Marketing segment includes our ownership interest in the Wood River and Borger Refineries and the marketing of our crude oil and natural gas, as well as third-party purchases and sales of product.

UPSTREAM

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 Pelican Lake operations. Prior to its divestiture in the fourth quarter of 2009, we also owned 100 percent of the Senlac property. We also 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.

Oil Sands highlights in 2010 include:
- Foster Creek achieving project payout status for royalty purposes in 2010;
- Receiving regulatory approval for the next three phases of expansion (F, G and H) at Foster Creek;
- Significant increases in production at Foster Creek and Christina Lake;
- Filing a joint application and EIA for our Narrows Lake project;
- Receiving approval for and commencing a pilot project at our Grand Rapids property; and
- Completing a large stratigraphic well program in 2010 and commencing a winter stratigraphic well program targeting to drill approximately 450 wells in 2011.

OIL SANDS - CRUDE OIL

Financial Results

(millions of dollars)	**2010**	2009	2008
Revenues	**$ 2,611**	$ 2,008	$ 2,337
Deduct (add)			
Realized financial hedging (gains) losses	**8**	(48)	75
Royalties	**276**	129	178
Net revenues	**2,327**	1,927	2,084
Expenses			
Production and mineral taxes	**-**	1	2

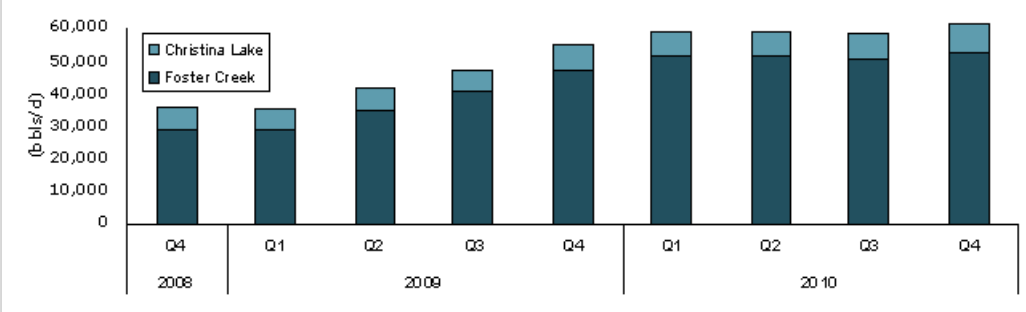
Transportation and blending	**934**	626	784
Operating	**341**	298	279
Operating Cash Flow	**1,052**	1,002	1,019
Capital Investment	**867**	629	758
Operating Cash Flow in Excess of Related Capital	**$ 185**	$ 373	$ 261

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Production Volumes

Crude oil *(bbls/d)*	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Foster Creek	**51,147**	**36%**	37,725	44%	26,220
Christina Lake	**7,898**	**18%**	6,698	57%	4,279
Total	**59,045**	**33%**	44,423	46%	30,499
Pelican Lake	**22,966**	**-8%**	24,870	-9%	27,324
Senlac	**-**	**-**	3,057	-5%	3,223
	82,011	**13%**	72,350	19%	61,046

Foster Creek and Christina Lake Production Volumes by Quarter



Net Revenues Variance

(millions of Canadian dollars)	2009 Net Revenues	Net Revenues Variances in: Price[1]	Volume	Royalties	Condensate[2]	**2010 Net Revenues**
Crude Oil	$ 1,927	80	178	(147)	289	**$ 2,327**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In 2010 our average crude oil sales price, excluding realized financial hedges, increased eight percent to $59.76 per bbl compared to 2009 consistent with the WCS benchmark increasing year over year. Financial hedging activities for 2010 resulted in realized losses of $8 million ($0.26 per bbl) compared to gains of $48 million ($1.87 per bbl) in 2009 (2008 – losses of $75 million; $3.37 per bbl).

Foster Creek production increased 36 percent primarily as a result of the phase D and E expansions, which commenced production late in the first quarter of 2009, as well as increased production from wedge wells. The 18 percent increase in production at Christina Lake was a result of increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake. At Pelican Lake, the decrease in production was the result of expected natural production declines. In the fourth quarter of 2009, we sold our Senlac heavy oil assets which had annual production of 3,057 bbls/d in 2009. Pipeline apportionments in the second half of 2010 did not significantly affect our production but did result in lower sales volumes and higher volumes in storage at the end of 2010.

Royalties increased by $147 million in 2010 compared to 2009 due to Foster Creek achieving project payout status for royalty purposes in the first quarter of 2010, along with an increased WTI price partially offset by a strengthened Canadian dollar used for calculating royalties, resulting in higher royalty rates. For 2010, the effective royalty rate for Foster Creek was 16.2 percent (2009 - 2.7 percent; 2008 – 1.1 percent) and for Christina Lake was 3.9 percent (2009 – 2.3 percent; 2008 – 1.0 percent).

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Pelican Lake royalties remained consistent as the increase in royalty rates due to higher prices was offset by lower volumes, which resulted in an effective royalty rate of 21.1 percent (2009 – 20.1 percent; 2008 – 20.2 percent).

Transportation and condensate blending costs, increased by $308 million in 2010. The increase in condensate blending costs of $289 million was primarily related to the volume of condensate required increasing due to higher production at Foster Creek and Christina Lake as well as an increase in the average cost of condensate, while blending costs at Pelican Lake were consistent with 2009. Transportation costs increased $19 million primarily due to the higher production volumes.

Operating costs increased by $43 million due to higher repairs and maintenance, increased field personnel in relation to phased expansions, higher chemical costs and purchased fuel volumes in relation to production increases. The increase in operating costs at Foster Creek and Christina Lake is due to a 33 percent increase in production volumes. At Pelican Lake, the increase in operating costs is attributable to polymer chemical costs and increased maintenance and workover expenses.

OIL SANDS – NATURAL GAS

Oil Sands also includes our 100 percent owned natural gas operations in Athabasca. Primarily as a result of natural declines, our natural gas production decreased to 43 MMcf/d (2009 – 53 MMcf/d; 2008 – 88 MMcf/d). As a result of lower production as well as lower natural gas prices, operating cash flow declined $104 million in 2010 to $77 million (2009 - $181 million; 2008 - $160 million).

OIL SANDS - CAPITAL INVESTMENT

(millions of dollars)	**2010**	2009	2008
Foster Creek	**$ 278**	$ 262	$ 356
Christina Lake	**346**	224	235
Total	**624**	486	591
Pelican Lake	**104**	72	62
New Resource Plays	**124**	17	53
Other[1]	**15**	54	52
	$ 867	$ 629	$ 758

(1) Includes Athabasca and Senlac.

Our Oil Sands capital investment in 2010 was primarily focused on the continued development of the next expansion phases of the Foster Creek and Christina Lake projects, as well as activities related to our Pelican Lake polymer flood. Our current plan is to increase gross production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the expected completion of Christina Lake phase C in 2011 and phase D in 2013.

Foster Creek capital investment in 2010 was higher as we received regulatory approval for the next phases of expansion (F, G and H). The majority of Foster Creek spending was related to drilling stratigraphic test wells, debottlenecking portions of the plant and preparation for the next phases of expansion including engineering and design, site preparation and camp construction. We are planning to accelerate the completion of Foster Creek phase F by up to 12 months which would result in production beginning in 2014.

At Christina Lake, capital investment was higher in 2010 due to construction and well pad drilling related to the phase C expansion, detailed design, procurement and construction for the phase D expansion and the drilling of stratigraphic test wells. We have chosen to accelerate completion of Christina Lake phase D by approximately six months and expect production to begin in 2013. Our current plan is to increase gross production capacity to approximately 98,000 bbls/d of bitumen with the expected completion of phase C in 2011 and phase D in 2013.

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Capital investment for Pelican Lake was primarily related to capital maintenance, facility additions for polymer flooding and infill drilling opportunities.

Capital investment in new resource plays in 2010 was mainly related to the drilling of stratigraphic test wells, as shown in the following table, regulatory advancement and the Grand Rapids pilot project including the drilling of a SAGD well pair and facility construction.

Gross Stratigraphic Wells

The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion while the stratigraphic test wells drilled at Narrows Lake, Grand Rapids, Telephone Lake and other emerging projects have been drilled to assess the quality of our projects and to support regulatory applications for project approval.

	2010	2009	2008
Foster Creek	**82**	65	144
Christina Lake	**24**	28	113
Total	**106**	93	257
Narrows Lake	**39**	-	-
Grand Rapids	**71**	17	8
Telephone Lake	**26**	-	5
Other	**17**	-	5
	259	110	275

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. These conventional crude oil and natural gas assets generate reliable production and cash flows.

Conventional highlights in 2010 include:
· Generating operating cash flow in excess of capital investment of more than $1.2 billion;

- Recompleted 1,194 Alberta natural gas wells adding low cost production;
- Weyburn production increasing as a result of our well optimization program, which partially offset natural declines;
- The continued development of the Bakken and Shaunavon plays where we more than doubled average production to about 2,000 bbls/d from less than 1,000 bbls/d in 2009; and
- Divesting of certain non-core properties for proceeds of $221 million, which reduced our annual crude oil and NGLs production volume two percent and our annual natural gas production volume four percent.

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CRUDE OIL and NGLs

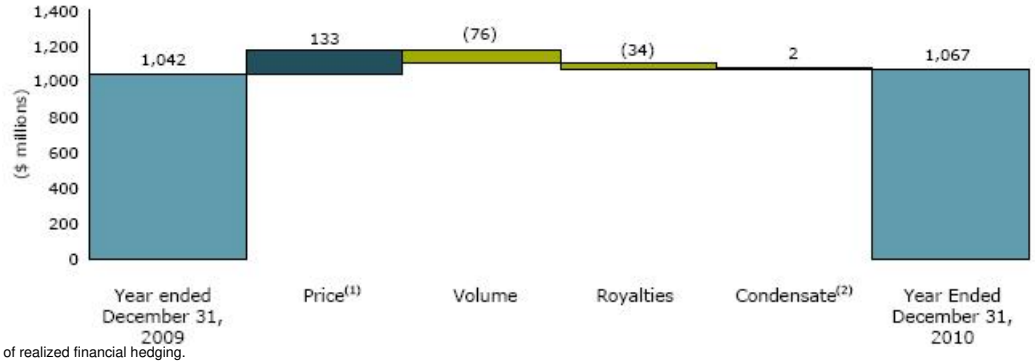
Financial Results

(millions of dollars)	2010	2009	2008
Revenues	**$ 1,229**	$ 1,161	$ 1,752
Deduct (add)			
Realized financial hedging (gains) losses	**9**	-	146
Royalties	**153**	119	208
Net revenues	**1,067**	1,042	1,398
Expenses			
Production and mineral taxes	**28**	28	40
Transportation and blending	**86**	87	154
Operating	**202**	174	171
Operating Cash Flow	**751**	753	1,033
Capital Investment	**358**	223	359
Operating Cash Flow in Excess of Related Capital	**$ 393**	$ 530	$ 674

Production Volumes

(bbls/d)	**2010**	**2010 vs 2009**	2009	2009 vs 2008	2008
Heavy Oil					
Alberta	**16,659**	**-7%**	17,888	-6%	19,062
Light and Medium Oil					
Alberta	**10,854**	**-9%**	11,959	-14%	13,941
Saskatchewan	**18,492**	**-%**	18,435	5%	17,551
NGLs	**1,171**	**-3%**	1,206	-%	1,203
	47,176	**-5%**	49,488	-4%	51,757

Net Revenues Variance



(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

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For 2010 the average crude oil and NGLs sales price, excluding realized hedging, increased 14 percent to $68.45 per bbl, consistent with the increases in benchmark prices. During 2010, realized financial hedging losses were $9 million ($0.54 per bbl) compared to gains of less than $1 million ($0.02 per bbl) in 2009 (2008 – losses of $146 million; $7.67 per bbl).

Production in 2010 was lower than 2009 due to expected natural declines, the divestiture of non-core producing properties in the first half of 2010 (which had an annual average production of approximately 1,000 bbls/d), production downtime due to weather and operational challenges in Alberta and Saskatchewan. Pipeline apportionments in the second half of 2010 did not significantly affect our production but did result in lower heavy oil sales prices as well as lower sales volumes and higher volumes in storage at the end of 2010. Partially offsetting these reductions was increased production from well optimizations at Weyburn and new wells in Alberta and Saskatchewan, including increased production at Bakken and Shaunavon.

Royalties for 2010 were $34 million higher as a result of higher commodity prices, as well as higher royalty rates arising from the higher commodity prices, which resulted in an effective royalty rate of 13.3 percent for 2010 (2009 - 11.4 percent; 2008 – 13.0 percent). The higher royalty rate was partially offset by lower volumes.

Production and mineral taxes were consistent in 2010 as higher commodity prices were offset by a prior period adjustment that had increased expenses in 2009.

Transportation and blending costs were consistent in 2010 as increases in the average cost of condensate were offset by decreased volumes of condensate required for blending with heavy oil.

Operating costs increased $28 million in 2010 primarily from increased workover activity mainly at Weyburn, higher repair and maintenance activity in all areas, higher trucking costs related to new production in Saskatchewan and higher indirect costs.

Our Conventional crude oil and NGLs operations generated $393 million of operating cash flow in excess of capital investment, a decrease of $137 million from 2009 mainly due to increased capital investment in 2010.

NATURAL GAS

Financial Results

(millions of dollars)	**2010**	2009	2008
Revenues	**$ 1,042**	$ 1,189	$ 2,588
Deduct (add)			
Realized financial hedging (gains) losses	**(264)**	(1,007)	76
Royalties	**17**	19	79
Net revenues	**1,289**	2,177	2,433
Expenses			
Production and mineral taxes	**6**	15	38
Transportation and blending	**44**	45	76
Operating	**235**	237	252
Operating Cash Flow	**1,004**	1,880	2,067
Capital Investment	**165**	243	489
Operating Cash Flow in Excess of Related Capital	**$ 839**	$ 1,637	$ 1,578

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Net Revenues Variance



(1) Includes the impact of realized financial hedging.

Our natural gas revenue and operating cash flow is down significantly due to lower realized prices. While our average natural gas price, excluding realized financial hedges, decreased slightly compared to 2009 and was consistent with the change in benchmark AECO price, the most significant decline in our revenue is a $743 million decline related to our realized financial hedging gains in 2010, which were $264 million ($1.04 per Mcf), compared to gains of $1,007 million ($3.52 per Mcf) in 2009 (2008 – losses of $76 million; $0.24 per Mcf) as a result of our settled fixed price contracts being approximately $3.00 per Mcf lower than the same period in 2009 due to the oversupply of natural gas and weaker market prices. For details of the specific pricing on our hedging program, see the notes to our Consolidated Financial Statements.

The cumulative impact of restricted natural gas capital spending in 2009 and 2010 as well as divestitures of non-core properties and natural production declines reduced our natural gas production volumes by 11 percent to 694 MMcf/d in 2010 (2009 – 784 MMcf/d; 2008 – 866 MMcf/d). The divestitures reduced our 2010 annual natural gas production by approximately 33 MMcf/d.

Royalties were slightly lower in 2010 as a result of adjustments related to prior years' production partially offset by lower volumes. The average royalty rate

for 2010 was 1.7 percent (2009 – 1.6 percent; 2008 – 3.1 percent).

Production and mineral taxes in 2010 were $9 million lower than 2009 mainly due to lower prices and volumes in 2010.

Costs related to transportation decreased slightly in 2010 due to lower volumes.

Operating expenses for 2010 decreased slightly as a result of reduced operations due to divestitures and lower production volumes. These declines were specifically related to lower property tax, repairs and maintenance, lower field staff and salaries as well as lower chemical costs, were offset with increased electricity prices and higher indirect costs.

Our Conventional natural gas operations generated $839 million of operating cash flow in excess of capital investment, a decrease of $798 million from 2009 mainly due to lower realized prices in 2010.

CONVENTIONAL - CAPITAL INVESTMENT

(millions of dollars)	**2010**	2009	2008
Alberta	**$ 303**	$ 340	$ 598
Saskatchewan	**220**	126	250
	$ 523	$ 466	$ 848

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For 2010, approximately 68 percent or $358 million of our capital investment was on our crude oil properties (2009 – 48 percent or $223 million; 2008 – 42 percent or $359 million). Capital investment in Alberta was focused on our oil program, our shallow gas projects and our liquids rich deep gas projects. Our capital investment in Saskatchewan continued to focus on drilling and facility work at Weyburn as well as appraisal projects at Lower Shaunavon and Bakken. In 2010, we drilled 36 wells in the Shaunavon and Bakken areas, 22 of which were on production at the end of 2010.

The following table details our Conventional drilling activity. Fewer natural gas wells were drilled in 2010 as our drilling program shifted towards oil wells from shallow gas wells. Well recompletions are mostly related to CBM development.

(net wells)	**2010**	2009	2008
Crude oil	**180**	105	93
Natural gas	**495**	502	1,375
Recompletions	**1,194**	855	1,017
Stratigraphic test wells	**9**	5	13

REFINING AND MARKETING

This operating segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. This segment's results also include the marketing group's third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Refining and Marketing highlights in 2010 include:
- The progression of the CORE project to approximately 91 percent complete from 71 percent at the beginning of the year; and
- Operating cash flow increasing in the fourth quarter by $112 million due to higher market crack spreads and increased utilization compared to the fourth quarter of 2009.

Financial Results

(millions of dollars)	**2010**	2009	2008
Revenues	**$ 8,228**	$ 6,922	$ 10,684
Purchased product	**7,664**	6,020	10,500
Gross margin	**564**	902	184
Operating expenses	**489**	534	543
Operating Cash Flow	**75**	368	(359)
Capital Investment	**656**	1,033	539
Capital Investment in Excess of Operating Cash Flow	**$ (581)**	$ (665)	$ (898)

Refining and Marketing revenues in 2010 increased 19 percent primarily due to higher prices for refined products and crude oil, as well as higher marketing volumes related to operational third-party sales.

Purchased product costs, which are determined on a first-in, first-out inventory valuation basis, increased 27 percent in 2010 due mainly to higher crude costs and operational third-party marketing volumes.

Our refining operations benefitted in the fourth quarter of 2010 from the wider light-heavy crude oil price differentials that occurred in the third quarter of 2010 as a result of pipeline disruptions. In addition, the initial start up phase of the Keystone pipeline in 2010 resulted in lengthy transportation times between the purchases of a portion of our Canadian heavy oil and the processing at the refinery and resulted in the product purchased in the third quarter of 2010 to be processed in the fourth quarter of 2010.

Operating costs, consisting mainly of labour, utilities and supplies, decreased eight percent in 2010 due to lower maintenance and decreased prices for utilities consumed at the refineries and a strengthened Canadian dollar.

2010 operating cash flow decreased by $293 million mainly due to planned turnarounds at both refineries, higher average crude costs as well as refinery optimization activities due primarily to weaker diesel and gasoline prices in the first half of 2010. Partially offsetting these decreases to operating cash flow was a strengthening of the Canadian dollar.

REFINERY OPERATIONS [1]

	2010	2009	2008
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**386**	394	423
Crude utilization *(%)*	**86**	87	93
Refined products *(Mbbls/d)*	**405**	417	448

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

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 bbls/d of crude oil and 45,000 bbls/d of NGLs, including processing capability to refine up to 145,000 bbls/d of blended heavy crude oil. Upon completion of the Wood River CORE project we expect to be able to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) primarily into motor fuels.

Our crude utilization was slightly lower in 2010 primarily due to a planned turnaround at the Wood River refinery, an extended turnaround at the Borger refinery, a power outage at Wood River, unplanned maintenance and refinery optimization activities.

CAPITAL INVESTMENT

(millions of dollars)	**2010**	2009	2008
Wood River Refinery	**$ 568**	$ 944	$ 477
Borger Refinery	**87**	88	45
Marketing	**1**	1	17
	$ 656	$ 1,033	$ 539

Our refining capital investment in 2010 continued to focus on the CORE project at the Wood River refinery. For 2010, of the $568 million capital expenditures at the Wood River refinery, $473 million were related to the CORE project. At December 31, 2010, the CORE project is approximately 91 percent complete. Unanticipated high water levels on the Mississippi River caused delays in the delivery schedule of various modules, which resulted in a shift to the timeline for this project. Commissioning of several of the process units has been completed with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than o riginally forecast.

The balance of the Wood River and Borger refineries 2010 capital investment was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CORPORATE AND ELIMINATIONS

Financial Results

(millions of dollars)	**2010**	2009	2008
Revenues	**$ (64)**	$ (778)	$ 731
Expenses ((add)/deduct)			
Operating	**3**	30	(13)
Purchased product	**(115)**	(110)	(159)
	$ 48	$ (698)	$ 903

The Corporate and Eliminations segment includes revenues that represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices. The segment also includes inter-segment 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. Operating expenses primarily relate to unrealized mark-to-market gains and losses on long-term power purchase contracts.

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

(millions of dollars)	**2010**	2009	2008
General and administrative	**$ 251**	$ 211	$ 171
Interest, net	**279**	244	233

Accretion of asset retirement obligation	**75**	45	40
Foreign exchange (gain) loss, net	**(51)**	304	(308)
(Gain) loss on divestiture of assets and other	**(4)**	(2)	3
	$ 550	$ 802	$ 139

General and administrative expenses were $40 million higher in 2010 primarily due to higher salaries and benefits as we move to implement our 10 year strategic plan and complete the transition to a new independent company as well as higher long-term incentive expense due to an increase in our share price.

Net interest in 2010 was $35 million higher than 2009 primarily as a result of a full year of standby fees incurred on our committed credit facility in 2010 as well as a full year of amortization on financing costs related to the setup of debt financing programs. Additionally, interest on long-term debt was slightly higher in 2010 as a result of a higher average interest rate and higher outstanding debt in 2010 compared to the proportionate share of Encana's debt allocated to Cenovus for the majority of 2009. The weighted average interest rate on outstanding debt for the year ended December 31, 2010 was 5.8 percent (2009 - 5.5 percent; 2008 – 5.5 percent).

In 2010 we reported foreign exchange gains of $51 million (2009 - losses of $304 million; 2008 – gains of $308 million), the majority of which were unrealized. The strengthening of the Canadian dollar during 2010 led to unrealized gains on our U.S. dollar debt, which was partially offset by unrealized losses on our U.S. dollar partnership contribution receivable.

The 2010 gain on divestiture of assets and other includes a gain of $12 million related to the acquisition of certain marine terminal facilities in Kitimat, British Columbia in the fourth quarter of 2010.

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Summary of Unrealized Mark-to-Market Gains (Losses)

The volatility of commodity prices has a significant impact on our net earnings, and as a means of managing this volatility, we enter into various financial instrument agreements. Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gains or losses reflected in corporate revenues are the result of volatility between periods in the forward commodity prices and changes in the balance of unsettled contracts. The table below provides a summary of the unrealized mark-to-market gains and losses recognized for each period. Additional information regarding financial instruments can be found in the notes to the Consolidated Financial Statements.

(millions of dollars)	**2010**	2009	2008
Revenues			
Crude Oil	**$ (92)**	$ (102)	$ 260
Natural Gas	**152**	(566)	630
	60	(668)	890
Expenses	**14**	30	(9)
	46	(698)	899
Income Tax Expense (Recovery)	**12**	(204)	263
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 34**	$ (494)	$ 636

DEPRECIATION, DEPLETION and AMORTIZATION

(millions of dollars)	**2010**	2009	2008
Upstream	**$ 1,039**	$ 1,250	$ 1,179
Refining and Marketing	**239**	232	205
Corporate and Eliminations	**32**	45	13
	$ 1,310	$ 1,527	$ 1,397

We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream DD&A decreased in 2010 primarily as a result of a reduced DD&A rate with the addition of proved reserves at Christina Lake phase D at the end of 2009. Refining and Marketing DD&A in 2010 includes an impairment loss of $37 million related to a processing unit determined to be a redundant asset and which would not be used in future operations at the Borger refinery. Offsetting this was lower DD&A on the refineries primarily related to a strengthening of the average U.S./Canadian dollar exchange rate in 2010. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX

(millions of dollars)	**2010**	2009	2008
Current income tax expense	**$ 82**	$ 934	$ 369
Future income tax expense (recovery)	**88**	(590)	405
Total Income taxes	**$ 170**	$ 344	$ 774

When comparing 2010 to 2009, our current tax expense declined and our future tax expense increased. Our current income tax expense in 2009 included the acceleration of income tax incurred as a result of certain corporate restructuring transactions which were required to give effect to the Arrangement and was offset by a recovery of future income tax in 2009. Our future income tax expense in 2010 includes a tax benefit of $107 million from the recognition of net capital losses expected to be realized against future taxable capital gains.

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These capital losses are attributable to an internal restructuring undertaken in 2010.

Our effective tax rate for 2010 was 14.6 percent compared to 29.6 percent in 2009 (2008 – 23.5 percent). The decrease in 2010 is primarily due to the recognition of the future tax benefits arising from net capital losses and from operating losses in our U.S. entities in 2010 compared to earnings in 2009.

It should be noted that our 2009 income tax expense was calculated as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction, and that the calculation was based on a number of assumptions, allocations and estimates consistent with the historical carve-out consolidated financial statements.

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; and
• Taxable foreign exchange gains not included in net earnings.

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

QUARTERLY FINANCIAL DATA

(millions of dollars, except per share amounts)	**Q4 2010**	**Q3 2010**	**Q2 2010**	**Q1 2010**	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008
Net Revenues	**3,172**	**3,115**	**3,195**	**3,491**	3,005	3,001	2,818	2,693	3,946
Operating Cash Flow [1]	**812**	**660**	**665**	**838**	954	1,134	1,173	928	121
Cash Flow [1]	**648**	**509**	**537**	**721**	235	924	945	741	(209)
- per share – diluted [2]	**0.86**	**0.68**	**0.71**	**0.96**	0.31	1.23	1.26	0.99	(0.28)
Operating Earnings [1]	**140**	**159**	**142**	**353**	169	427	512	414	(159)
- per share – diluted [2]	**0.19**	**0.21**	**0.19**	**0.47**	0.23	0.57	0.68	0.55	(0.21)
Net Earnings	**73**	**223**	**172**	**525**	42	101	160	515	490
- per share – basic [2]	**0.10**	**0.30**	**0.23**	**0.70**	0.06	0.13	0.21	0.69	0.65
- per share – diluted [2]	**0.10**	**0.30**	**0.23**	**0.70**	0.06	0.13	0.21	0.69	0.65
Capital Investment	**706**	**480**	**443**	**493**	507	515	488	652	760
Free Cash Flow [1]	**(58)**	**29**	**94**	**228**	(272)	409	457	89	(969)
Cash Dividends [3]	**151**	**150**	**150**	**150**	159	n/a	n/a	n/a	n/a
- per share [3]	**0.20**	**0.20**	**0.20**	**0.20**	US$0.20	n/a	n/a	n/a	n/a

(1) Non-GAAP measure defined within this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement, wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.
(3) 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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In the fourth quarter of 2010 cash flow increased $413 million compared to the fourth quarter of 2009 primarily due to:

- A $526 million decrease in current income tax expense as a result of 2009 including acceleration of current income tax along with 2010 including the utilization of claims from tax pools that we received as a result of the Arrangement, as well as lower realized hedging gains in 2010; and
- A $112 million increase in operating cash flow from Refining and Marketing primarily due to higher market crack spreads and increased utilization compared to the fourth quarter of 2009.

The increases in our fourth quarter 2010 cash flow were partially offset by:

- A 22 percent decrease in the average realized natural gas price to $5.05 per Mcf from $6.44 per Mcf;
- A 14 percent decrease in natural gas production primarily due to the disposition of certain non-core properties and reduced natural gas capital expenditures;
- A five percent decrease in our average realized liquids price to $61.46 per bbl compared to $64.74 per bbl;
- A decrease in crude oil and NGLs volumes sold due to pipeline apportionments in the fourth quarter of 2010;
- Higher crude oil and NGLs operating costs consistent with the increase in production;
- An increase in general and administrative and net interest expense of $13 million; and
- An increase in royalties of $10 million primarily as a result of Foster Creek achieving royalty payout as well as higher WTI prices partially offset by a strengthened average Canadian dollar used for calculating royalties.

Our net earnings in the fourth quarter of 2010 were $31 million higher than 2009. The factors that increased our cash flow in the fourth quarter also increased net earnings. Other significant factors that impacted our fourth quarter 2010 net earnings include:

- Future income tax expense, excluding the impact of the unrealized financial hedging gains, in 2010 of $37 million, compared to a recovery of $351 million in 2009;
- Unrealized mark-to-market losses, after-tax, of $197 million, compared to losses of $92 million, after-tax, in 2009;

- Unrealized foreign exchange gains of $30 million in 2010 compared to losses of $86 million in 2009; and
- A decrease of $28 million in DD&A.

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"). Prior to the year ended December 31, 2010, we presented our reserves estimates in accordance with certain U.S. disclosure requirements pursuant to an exemption from certain of the NI 51-101 requirements. Year over year comparisons are in reference to the previously disclosed December 31, 2009 estimates prepared by independent qualified reserves evaluators ("IQREs") and determined using 2009 12 month average constant prices and costs, as prescribed by the U.S. Securities and Exchange Commission ("SEC").

We retain two IQREs, McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd., to evaluate and prepare reports on 100 percent of our reserves. McDaniel also evaluated 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to 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 recommend approval of the reserves and resources disclosure to the Board.

Highlights in 2010 include:
- Improved recovery factor and expansion of development area at Foster Creek led to substantial growth in our proved bitumen reserves by 288 MMbbls, a 33 percent increase from 2009;
- Conventional oil and NGLs proved reserves grew one percent; and

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- An overall nine percent decline in natural gas and CBM proved reserves due to extensions and improved recoveries as well as technical revisions not enough to offset production and dispositions.

The reserves data presented summarizes our bitumen, heavy oil, light and medium oil plus NGLs, and natural gas plus CBM reserves using McDaniel's January 1, 2011 forecast prices and costs. We hold significant freehold 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.

Information with respect to pricing as well as additional reserves information is contained in our Annual Information Form ("AIF") for the year ended December 31, 2010, available at www.sedar.com and on our website at www.cenovus.com.

RESERVES AT DECEMBER 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2010**(1)	2009(2)	**2010**(1)	2009(2)	**2010**(1)	2009(2)	**2010**(1)	2009(2)
Proved	**1,154**	866	**169**	165	**111**	112	**1,390**	1,529
Probable	**523**	479	**97**	104	**49**	53	**410**	436
Proved plus Probable	**1,677**	1,345	**266**	269	**160**	165	**1,800**	1,965

(1) Refers to 2010 estimates prepared by the IQREs using McDaniel January 1, 2011 forecast prices and costs.
(2) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.

RECONCILIATION OF PROVED RESERVES

Before Royalties	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2009 (SEC) (1)	866	165	112	1,529
Transition to NI 51-101 Standards (2)	-	(1)	(3)	128
December 31, 2009 (NI 51-101) (3)	866	164	109	1,657
Extensions and Improved Recovery	270	9	11	45
Technical Revisions	40	15	1	60
Economic Factors	-	-	-	(18)
Dispositions	-	(5)	-	(87)
Production	(22)	(14)	(10)	(267)
December 31, 2010	1,154	169	111	1,390
Year over year change	288	4	(1)	(139)
	33%	2%	(1%)	(9%)

(1) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.
(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of royalty interest reserves from the before royalties reserves totals. See Oil and Gas Information in the Advisory section of this MD&A.
(3) Determined using McDaniel January 1, 2010 forecast prices and costs.

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**

December 31, 2009 (SEC) [1]	479	104	53	436
Transition to NI 51-101 Standards [2]	-	(1)	(2)	52
December 31, 2009 (NI 51-101) [3]	479	103	51	488
Extensions and Improved Recovery	132	5	(1)	12
Technical Revisions	(88)	(10)	(1)	(82)
Economic Factors	-	-	-	7
Dispositions	-	(1)	-	(15)
December 31, 2010	523	97	49	410
Year over year change	44	(7)	(4)	(26)
	9%	(7%)	(8%)	(6%)

(1) Refers to previously disclosed estimates prepared by the IQREs using 2009 constant prices and costs.
(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of royalty interest reserves from the before royalties reserves totals. See Oil and Gas Information in the Advisory section of this MD&A.
(3) Determined using McDaniel January 1, 2010 forecast prices and costs.

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In 2010, proved and proved plus probable bitumen reserves increased by approximately 33 and 25 percent respectively. This was primarily a result of receiving regulatory approval to expand the development area at Foster Creek and from improvements to overall recovery based on operating performance. Incremental recovery from wedge wells, drilled between existing producers, and improved recovery resulting from better than expected drainage from existing wells also contributed to the increase.

In 2010, proved heavy oil reserves increased by approximately two percent primarily as a result of expanding polymer flood areas and their successful performance at Pelican Lake. Probable heavy oil reserves decreased by approximately seven percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately one percent.

In 2010, proved light and medium oil and NGLs reserves decreased by approximately one percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and their successful performance at Weyburn being offset by current year production. Probable light and medium oil and NGLs reserves decreased by eight percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately three percent.

In 2010, proved natural gas reserves declined by approximately nine percent as extensions and technical revisions did not offset production and the divestiture of some of our natural gas assets. Probable natural gas reserves and proved plus probable reserves declined by approximately six percent and eight percent respectively.

RESOURCES AT DECEMBER 31

	Bitumen (billions of barrels)	
Before Royalties	**2010[1]**	2009[2]
Economic contingent resources[3]		
Low Estimate	**4.4**	3.9
Best Estimate	**6.1**	5.4
High Estimate	**8.0**	7.3
Prospective resources[4]		
Low Estimate	**7.3**	7.8
Best Estimate	**12.3**	12.6
High Estimate	**21.7**	21.4

(1) Refers to estimates prepared by McDaniel, using McDaniel January 1, 2011 forecast prices and costs.
(2) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.
(3) See Oil and Gas Information in the Advisory section of this MD&A for definitions of contingent resources, economic contingent 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.
(4) 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.

Best estimate economic contingent resources increased 0.7 billion barrels or 13 percent relative to 2009. This increase is primarily as a result of significant stratigraphic well drilling converting prospective resources to contingent resources, and positive technical revisions to volumetric estimates and recovery factor estimates. Best estimate prospective resources declined 0.3 billion barrels or two percent relative to 2009, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic drilling.

The contingencies which must be overcome to enable the bitumen economic contingent resources to be classified as reserves include submission of regulatory applications with no major issues raised, access to markets, and intent to proceed by the operator and partners as evidenced by a development plan with major capital expenditures planned within five years.

Additional reserves and other oil and gas information, including the risks and uncertainties associated with reserves and resource estimates, is contained in our AIF, available at www.sedar.com and on our website at www.cenovus.com.

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LIQUIDITY AND CAPITAL RESOURCES

(millions of dollars)	**2010**	2009	2008

Net cash from (used in)			
Operating activities	**$ 2,594**	$ 3,039	$ 3,225
Investing activities	**(1,796)**	(2,063)	(2,109)
Net cash provided (used) before Financing activities	**798**	976	1,116
Financing activities	**(631)**	(977)	(1,227)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(22)**	(32)	1
Increase (decrease) in cash and cash equivalents	**$ 145**	$ (33)	$ (110)

OPERATING ACTIVITIES

Net cash from operating activities decreased $445 million in 2010 compared to 2009 mainly because of lower cash flow. Cash flow was $2,415 million during 2010 (2009 - $2,845 million; 2008 - $3,115 million). Reasons for this change are discussed in the Cash Flow section of this MD&A. Cash from operating activities was also impacted by the net change in other assets and liabilities and the net change in non-cash working capital.

Excluding the impact of risk management assets and liabilities, we had working capital of $290 million at December 31, 2010 compared to working capital of $479 million at December 31, 2009. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2010 decreased to $1,796 million from $2,063 million in 2009 (2008 - $2,109 million). Capital expenditures increased in 2010 to $2,208 million compared to $2,165 million in 2009 (2008 - $2,204 million). Total divestiture proceeds increased in 2010 to $309 million compared to $222 million in 2009 (2008 - $48 million). The changes to our capital expenditures are discussed under the Net Capital Investment and Operating Segment sections of this MD&A. Also decreasing the cash used in investing was the net change in non-cash working capital, which increased cash and cash equivalents by $99 million in 2010 compared to a $95 million decrease in 2009 (2008 – increase of $96 million).

FINANCING ACTIVITIES

Cenovus has a committed credit facility and a commercial paper program that are used to manage our short term cash requirements.

In 2010, we re-negotiated our $2.5 billion credit facility by combining the two existing tranches into a single tranche and extending the maturity to November 30, 2014. At December 31, 2010, no amounts were drawn on the committed credit facility.

In 2010, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issue 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, 2010, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in July 2012.

In 2010, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$1.5 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. The terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates, will be determined at the date of issue. At December 31, 2010, no notes have been issued under this U.S. shelf prospectus.

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The U.S. shelf prospectus expires in August 2012.

In 2010, we declared and paid quarterly dividends of $0.20 per share (2009 – U.S.$0.20 per share in the fourth quarter). Dividend payments for 2010 totaled $601 million (2009 - $159 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities for 2010 was $631 million (2009 – $977 million; 2008 - $1,227 million). The 2010 decrease in net cash used in financing was a result of net financing transactions with Encana in 2009 related to the Arrangement. In 2009, we completed a private offering of senior unsecured notes for net proceeds of $3,718 million (U.S.$3,468 million) as well as the repayment of the $3.7 billion (U.S.$3.5 billion) demand promissory note to Encana. In 2010, substantially all of these notes were exchanged for notes registered under the Securities Act of 1933 with the same terms and conditions as the original issued notes. Our debt was $3,432 million as at December 31, 2010 and does not require any payments of principal until 2014.

As at December 31, 2010, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	2010	2009	2008
Debt to Capitalization	**26%**	28%	28%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x	0.8x

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest, income taxes, DD&A, accretion of asset retirement obligations, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss). Debt is defined as the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. These metrics are used to steward our overall debt position as measures of our overall financial strength.

We 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 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, 2010 there were 752.7 million (2009 – 751.3 million) common shares outstanding and no preferred shares outstanding.

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

The Cenovus Employee 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 initial grant after one year, an additional 30 percent of the initial grant after two years and are fully exercisable after three years and expire five to seven years after the date granted. Options granted 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 price of their option in exchange for surrendering their option.

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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.

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.

At December 31, 2010, Cenovus employees held approximately 19.1 million options, of which 7.7 million were exercisable. At December 31, 2010, Encana employees held approximately 17.2 million Cenovus replacement options, of which 10.8 million were exercisable. 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.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

	Expected Payment Date						
(millions of dollars)	2011	2012	2013	2014	2015	2016+	Total
Long-term Debt[1]	$ -	$ -	$ -	$ 796	$ -	$ 2,685	$ 3,481
Partnership Contribution Payable[1]	343	364	386	410	435	581	2,519
Asset Retirement Obligation	100	2	2	2	2	6,012	6,120
Pipeline Transportation	107	93	167	167	166	953	1,653
Purchases of Goods and Services	157	23	12	10	7	23	232
Product Purchases	23	18	18	18	18	7	102
Operating Leases[2]	33	87	88	85	78	1,553	1,924
Capital Commitments	91	71	4	4	4	14	188
Other Long-term Commitments	4	2	1	1	-	1	9
Total Payments	$ 858	$ 660	$ 678	$ 1,493	$ 710	$ 11,829	$ 16,228
Product Sales	$ 50	$ 52	$ 54	$ 56	$ 57	$ 63	$ 332
Partnership Contribution Receivable[1]	$ 346	$ 364	$ 384	$ 405	$ 427	$ 565	$ 2,491

(1) Principal component only. See notes to the Consolidated Financial Statements.
(2) Operating leases consist of building leases.

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

As at December 31, 2010, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 73 Bcf of natural gas at a weighted average price of US$4.54 per Mcf.

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

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LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such 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 and liquidity risk;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

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. 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 include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

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. Management monitors our operational and financial risk strategies to proactively respond to the changing economic conditions and to eliminate, mitigate or reduce the risk. 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 cash resources are 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, 2010, 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.

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.

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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 crude oil and natural gas price differentials with fixed price differential and basis swaps between our production areas and various sales points. We have mitigated some of our exposure to electricity consumption costs, with two derivative contracts whic h expire on January 1, 2018.

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 is with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policies 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 Canada and the United States 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, 2010, no amounts were drawn on our committed credit facility. 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.

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, 2010, 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.

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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.

Our ability to operate, generate cash flows, complete projects and value reserves is dependent on financial risks, including commodity prices mentioned above, 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 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.

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 process called Lookback and Learning. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational 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 Lookback and Learning results are analyzed in relation to our capital program with the results and identified learnings shared across our company.

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.

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.

SAFETY, ENVIRONMENTAL AND REGULATORY RISKS

We are engaged in the relatively high risk activities of crude oil and natural gas development and production and refining. 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 the environment, for approval by our Board and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, healt h 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.

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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.

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 and 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. Further information regarding the status of each project can be found in the Operating Segments section of this MD&A.

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 emissions 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, 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.

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 2010 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 carbon dioxide sequestration, a focus on energy efficiency and the development of technology to reduce GHG emissions.

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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.

ALBERTA'S ROYALTY FRAMEWORK

In 2010, the Government of Alberta outlined changes to the royalty structure in the province. The updates to conventional crude oil and natural gas royalty structure released in the first quarter of 2010 included:

- A five percent maximum royalty rate on new gas and conventional oil wells for a period of 12 months or 0.5 billion cubic feet equivalent for gas wells or 50,000 barrels of oil equivalent for oil wells, whichever comes first. The five percent royalty rate was originally created with the New Well Incentive under the Energy Incentive Program that was released on March 3, 2009 and was set to expire on March 31, 2011, but is now permanently in place;
- The maximum royalty rate for conventional oil will decrease to 40 percent from 50 percent and the maximum natural gas royalty rate will decrease to 36 percent from 50 percent; and
- Effective January 1, 2011 no additional wells will be allowed under the Transitional Royalty Program ("TRP") that went into effect on January 1, 2009. The TRP allows for a one time option of selecting transitional royalty rates on new natural gas or conventional oil wells drilled between 1,000 to 3,500 metres in depth. Any wells that are elected under the TRP can continue to use this program until December 31, 2013.

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Updates released in the second quarter of 2010 were primarily focused on supporting deep basin gas drilling and improving the economics of unconventional gas plays, as well as horizontal oil and gas drilling. These updates included:

- A maximum royalty rate of five percent for all products produced from horizontal oil or horizontal non-oil sands wells, with volume and production month limits set according to the depth of the well. Horizontal oil and non-oil sands wells are defined by the ERCB;
- Wells defined as horizontal natural gas wells by the ERCB will have a maximum five percent royalty rate on all production for a period of 18 producing months or 500 MMcf of gas equivalent production;
- CBM wells that produce exclusively from areas defined by the ERCB as coal will have a maximum royalty rate of five percent on all products produced in the first 36 months with a production limit of 750 MMcf of gas equivalent; and
- The Natural Gas Deep Drilling program was made permanent and was modified and simplified. Modifications include the reduction of the minimum well depth to 2,000 metres; elimination of well target, spacing and pool boundary restrictions; all lateral wells qualify for credits; increased credits between 3,500 and 5,000 metres; and removal of maximum well depth.

Also included as part of the royalty structure changes released in the second quarter were updates to the royalty curves for conventional oil and natural gas. The effective date of the new curves is January 1, 2011.

For Cenovus, the main impact of these royalty changes is expected to be a positive improvement to the economics of our oil drilling program for certain properties in our Conventional operating segment and any future shale oil developments in Alberta.

ALBERTA'S REGULATORY FRAMEWORK

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 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 Projects team's recommendations and is expected to begin implementing those recommendations in the first half of 2011.

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act ("ALSA"), 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. The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while consider ing social and economic impacts. In August 2010, the Lower Athabasca Regional Advisory Council ("RAC") provided its vision document to the Government of Alberta regarding the LARP. Cenovus is actively participating in the feedback process as a stakeholder with significant activities in the region and will continue to monitor developments going forward. The Government of Alberta is expected to respond to the RAC advice with its own LARP recommendations. It is possible that the RAC vision, if adopted in its current form by the Government of Alberta, may negatively impact Cenovus's access to certain resource properties or limit the pace of development due to environmental limits and thresholds.

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.

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Our Corporate Responsibility ("CR") policy has been updated to ensure that it continues to drive our commitments, strategy and reporting, and also 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 was released on December 1, 2010 and is available on our website at www.cenovus.com.

In 2010, we released our "Corporate Responsibility Performance Highlights" fact sheet and launched the CR section of our website. The two-page fact sheet introduced Cenovus to our stakeholders and provided a snapshot of our 2009 CR performance. It was distributed to all of our staff, including contractors and staff in the field and to over 1,000 of our external contacts. We also created a more detailed "Corporate Responsibility 2009 Performance Measures Report" to complement the fact sheet. The Performance Measures Report organizes all 2009 CR metrics into one document and is available on our website at www.cenovus.com.

As our CR reporting process matures, indicators will be developed that better reflect Cenovus's operations and challenges. These indicators will be

integrated into our CR reporting and will expand our online presence through our website.

ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of GAAP that have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. 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 year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

Our results for the periods prior to the Arrangement, being January 1 to November 30, 2009 and January 1 to December 31, 2008, have been prepared on a "carve-out" accounting basis, whereby the results 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 the 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 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 periods presented.

Oil and Gas Reserves

All of our oil and gas reserves are evaluated and reported to Cenovus by the IQREs. 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.

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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 asset retirement obligations.

Property, Plant and Equipment – DD&A

Crude oil and natural gas properties are accounted for in accordance with the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, exploration for, and the development of crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, plus estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

Asset Impairments

Under GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount. The recoverable amount is calculated as the total undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:
i) the fair value of proved and probable reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

We also perform an annual impairment test on goodwill, whereby the fair value of each reporting unit is determined and compared to the book value of the reporting unit. A reporting unit has all assets, including goodwill, and liabilities allocated to the country cost centre level.

For the above impairment tests, fair value is calculated as the cash flows from oil and gas properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. In order to estimate future cash flows, we are required to make a number of assumptions and estimates, including quantities of reserves, future commodity prices as well as development and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's carrying value.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the carrying amount exceeds the fair value.

Business Combinations

The purchase price of business combinations and asset acquisitions is allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the use of assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation will have a direct impact on our future net earnings, largely due to the impact on the calculation of DD&A rates or asset impairment tests.

Asset Retirement Obligations

We are required to recognize an asset retirement obligation ("ARO") liability for the future abandonment and reclamation costs associated with our property, plant and equipment. ARO is only recognized to the extent there is a legal obligation associated with the retirement of a tangible long-lived asset that we are required to settle as a result of an existing or enacted law.

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Our calculation of ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal and regulatory requirements, contracts and current technologies. There are many assumptions used in the estimate of the ARO liability which can be subject to change based on experience. These assumptions include: the estimated cost of reclaiming producing well sites, crude oil and natural gas processing plants and refining facilities; inflation rates; credit-adjusted risk free rates; and the timing of retirement of assets. At the end of each year, we review our assumptions and estimates and any changes to the ARO liability are discounted to present value using a credit-adjusted risk-free discount rate.

Compensation Plans

We have obligations for payments to our employees related to our stock option and incentive plans. The obligations provide for a range of payouts based on key predetermined performance measures and the cost of these plans is expensed based on expected payouts. The amounts to be paid, if any, may vary from the current estimate.

We also have obligations for payments to our employees related to stock option plans of Encana. The financial liability for these obligations is accrued using the fair value method, and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation fluctuates, as it is based on assumptions for the risk-free discount rate, dividend yield, as well as the volatility of Encana's share price.

Risk Management Activities

We use various derivative financial instruments to manage our commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. The estimated fair value of derivative financial instruments is determined using appropriate valuation models and methodologies. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, we rely primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. 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.

Income Taxes

We follow the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires the interpretation of changing laws and regulations, for example changing income tax rates, and making certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments have a significant impact on our provision for current and future income tax, and will have a direct impact on our future net earnings.

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations", which replaces CICA Handbook Section 1581 of the same name. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the Statement of Earnings. This accounting policy was applied to the November 1, 2010 purchase of the marine terminal facilities.

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In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements". Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest to be classified as a separate component of equity. In addition, net earnings, and components of other comprehensive income are attributed to both the parent and non-controlling interest. The early adoption of these standards did not have a material impact on the Company's Consolidated Financial Statements for the year ended December 31, 2010.

These standards are converged with International Financial Reporting Standards ("IFRS").

RECENT ACCOUNTING PRONOUNCEMENTS

There are no pending GAAP accounting pronouncements, other than the requirement to adopt IFRS in 2011, as discussed below.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

We are required to report our results in accordance with IFRS beginning with the three month period ending March 31, 2011. We have a detailed

changeover plan, which includes the preparation of required comparative information for 2010. We continue to be on schedule with our plan, and expect that the adoption of IFRS will not have a significant impact or influence on our business, operations or strategies.

The information below summarizes our accounting policies and opening balance sheet information, which were disclosed in our MD&A for previous periods. It also includes additional information on the estimated IFRS impacts on our financial results for the year ended December 31, 2010.

Our IFRS financial results have not yet been finalized because:

- The results remain subject to further review by management;
- We are continuing to monitor any new or amended IFRS issued by the International Accounting Standards Board that could affect our choice of accounting policies;
- Our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011; and
- The results are unaudited and are subject to additional audit work by our external auditors.

Significant Impacts of IFRS

The following areas are the most significantly affected by the adoption of IFRS:

- Upstream Property, Plant and Equipment ("PP&E"), including:
  - Exploration and Evaluation costs
  - Asset retirement obligation
  - Transition on date of adoption of IFRS
  - DD&A
  - Gains and losses on divestitures
- Refining Assets
- Impairment testing
- Stock-based compensation
- Income taxes

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Upstream PP&E

Exploration and Evaluation costs
During the exploration and evaluation ("E&E") phase, we capitalized costs incurred for these projects under GAAP. While this capitalization policy has not changed under IFRS, these costs will be reported separately as E&E assets, rather than being included in PP&E.

Asset Retirement Obligation
Under GAAP, the discount rates used to estimate the ARO liability were not updated to current market discount rates, while under IFRS, the discount rate is updated each reporting period. This difference in accounting policy did not have a significant impact on either our opening balance sheet or our net earnings for the year ended December 31, 2010. However, our ARO liability as of December 31, 2010 was higher under IFRS as a result of changes to the discount rate used to estimate the liability. The impact is expected to be less than $200 million.

Transition adjustments on date of adoption of IFRS – January 1, 2010
Under GAAP, we follow full cost accounting, while 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. Using this exemption, we reclassified the cost of our unproved properties from Upstream PP&E to the new E&E asset category, and allocated the remainder of our Upstream full cost pool to our IFRS areas based on the relative fair value of each area. Fair value was calculated using the estimated future net cash flows from proved reserves, discounted at 10 percent, since this was considered to be an appropriate estimate of the relative fair value of each of our IFRS areas. This approach was also consistent with the allocation method which was required to be used in the formati on of Cenovus. The allocation process did not affect the net book value of our Upstream PP&E as no IFRS impairments were recognized.

DD&A
Under GAAP, we calculated our DD&A rate at the country cost centre level. Under IFRS, this rate is calculated at a lower unit of account level, which resulted in our Upstream DD&A for the year ended December 31, 2010 increasing by less than $150 million. The increase in DD&A is primarily due to separating the long life reserves associated with the Foster Creek and Christina Lake properties from the rest of the full cost pool.

Gains and losses on divestitures
Full cost accounting under GAAP required that gains or losses on divestitures of PP&E only be recognized when the disposal would affect our DD&A rate by 20 percent or more. Under IFRS, we are required to recognize all gains and losses on upstream property divestitures. For the year ended December 31, 2010, we recognized gains on divestiture of oil and gas properties of about $125 million. Under GAAP, these gains were credited to the full cost pool, and would have resulted in a lower GAAP DD&A rate in future years compared to our IFRS DD&A rates.

Refining Assets

In our IFRS opening balance sheet, we elected to re-measure the carrying value of our refineries to their fair value, which permanently reduced their carrying value by approximately $2.6 billion ($1.6 billion, after-tax). In addition, having revalued the refineries to their fair values, it was also determined that the Refining deferred asset, which had a carrying value of $121 million at January 1, 2010, was fully impaired under IFRS. The impairment loss on a refining process unit recognized under GAAP was reduced under IFRS due to the January 1, 2010 fair value election. The impact of these three IFRS adjustments was a decrease in our Refining and Marketing DD&A of less than $150 million for the year ended December 31, 2010.

Impairment Testing

In the first step for all of our GAAP impairment tests (Upstream, Refining and Goodwill), future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for Upstream PP&E, impairment testing was performed at the country cost centre level, while under IFRS, it is performed at

the lower cash-generating unit level.

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There was no impact on our Upstream PP&E, Refining PP&E or goodwill with this change in accounting policy.

Stock-based Compensation

Under GAAP, obligations for cash payments under stock-based compensation plans were accrued using the intrinsic method, while under IFRS these obligations are accounted for using the fair value method. While the carrying value in each reporting period will be different under IFRS compared to GAAP, the cumulative expense recognized over the life of the instrument under both methods will not be different. This difference in policy did not have a significant impact on either our IFRS opening balance sheet or our net earnings for the year ended December 31, 2010.

Income Taxes

The carrying amounts of our tax balances have been directly impacted by the tax effects resulting from changes in our accounting policies. The future income tax liability on our IFRS opening balance sheet was reduced by approximately $1 billion, primarily due to the fair value election on our refineries. For the year ended December 31, 2010, our income tax expense increased primarily related to the tax effects on the recognition of gains on our PP&E divestitures.

Summary of IFRS impacts to December 31, 2010

The net effect of the significant adjustments above is an increase to our net earnings mainly due to the gain on divestiture of oil and gas properties. All of the other IFRS adjustments are not significant. In total, we estimate an increase to our net earnings under IFRS for the year ended December 31, 2010 of less than $120 million.

The most significant impacts on our December 31, 2010 balance sheet are as follows:
- Decrease in PP&E of approximately $2.2 billion;
- Re-classification of approximately $0.7 billion of Upstream PP&E to E&E assets;
- Decrease in Other assets of approximately $0.1 billion;
- Increase in Asset Retirement Obligation of approximately $0.2 billion;
- Decrease in Future Income Taxes of approximately $0.9 billion; and
- Decrease in Shareholders' Equity of approximately $1.6 billion.

These balance sheet changes increased our Debt to Capitalization ratio at December 31, 2010, from 26 percent to 29 percent, which is below our target range of 30 percent to 40 percent.

In terms of our cash flow statement for the year ended December 31, 2010, the IFRS adjustments did not have a significant impact on cash from operating activities, cash used in investing activities, or cash from financing activities. Furthermore, the IFRS adjustments did not have a significant impact on cash flow, which is our non-GAAP measure defined earlier in this MD&A.

Internal Controls Over Financial Reporting & Disclosure Controls and Procedures

During the fourth quarter of 2010, we have updated our internal controls documentation related to external financial reporting processes, including disclosure controls and procedures. We do not expect that the adoption of IFRS will have a significant impact on any of our internal control processes.

Financial Reporting Expertise

In terms of financial literacy, we held additional internal IFRS education sessions in the fourth quarter of 2010. These education sessions will continue during 2011 across all of our finance teams to ensure that there is a strong level of knowledge of IFRS throughout the organization. We will also continue to educate our external stakeholders, primarily by disclosing and explaining the significant adjustments from GAAP to IFRS.

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OUTLOOK

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 new 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 resources in multiple phases using a low cost manufacturing-like approach;
- Leadership in low cost oil sands development enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- To primarily fund growth internally through free cash flow generation mainly from our established conventional crude oil and natural gas assets along with sufficient capacity on our debt facilities for additional cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core oil and gas assets;
- Maintaining a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and

· Maintaining a meaningful dividend.

We expect that global oil demand will continue to increase which should allow for continued strength in WTI prices. We are expecting the light-heavy differential, represented by WCS crude oil prices, to remain close to historical trends due to pipeline disruptions and Canadian heavy crude supply growing in advance of new coking capacity and pipeline access to the Gulf of Mexico. Once the new refinery and pipeline capacity is in place there should be strengthening in WCS. If the pipeline disruptions and apportionment that occurred in the second half of 2010 persist, we expect widened light-heavy oil differentials to continue in 2011, which should benefit our refining financial results. Offsetting this is a relatively weak price outlook for natural gas and refining margins although refining margins will benefit from any near term congestion in inland markets. The key challenges that need to be effectively managed to enable our growth are commodity price volatility, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our 2010 results is discussed in the Risk Management section of this MD&A and in our AIF for the year ended December 31, 2010.

We expect our 2011 capital investment program to be primarily internally funded through cash flow with sufficient capacity on our debt facilities for additional cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional crude oil and natural gas assets in Alberta and Saskatchewan are key to providing free cash flow to enable oil sands growth. Our 10 year business plan outlines how Cenovus expects to reach net oil sands production of 300,000 bbls/d by the end of 2019. We are planning continued expansions at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve this objective.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have historically benefitted from this strategy, there is no certainty that we will continue to derive such benefits in the future.

We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

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ADVISORY

FORWARD-LOOKING INFORMATION

This MD&A 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 MD&A 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 expenditure s, 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 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 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; 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 a desirable debt to cash flow ratio; our ability to access external sources of debt and equity capital; success of hedging strategies; 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 relationshi p 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 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 re gulations, 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 Annual Information Form/Form 40-F for the year ended December 31, 2010, available at www.sedar.com, www.sec.gov and www.cenovus.com.

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OIL AND GAS INFORMATION

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2010 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 National Instrument 51-101.

- Contingent Resources are those quantities of petroleum 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.
- 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 2010 reserves evaluation, which comply with NI 51-101 requirements.
- Prospective Resources are those quantities of 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.

Additional information relating to our oil and gas reserves and resources is presented in our AIF for the year ended December 31, 2010, available at www.sedar.com and on our website at www.cenovus.com.

CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

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

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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
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
WTI	West Texas Intermediate
WCS	Western Canada Select

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

The Arrangement refers to the commencement of independent operations on December 1, 2009 following an agreement with Encana creating two independent publicly traded energy companies.

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by GAAP 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 GAAP. The definition and reconciliation of each non-GAAP measure, is presented in this MD&A.

ADDITIONAL INFORMATION

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 Energy Inc., including our AIF for the year ended December 31, 2010, is available on SEDAR at www.sedar.com and on our website at www.cenovus.com.

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Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2010

(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 Canadian generally accepted accounting principles 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 at least on a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis an d 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, 2010. 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 that date.

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, 2010 as stated in their Auditors' Report. 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 18, 2011

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Independent Auditor's Report

To the Shareholders of Cenovus Energy Inc.

We have completed integrated audits of Cenovus Energy Inc.'s 2010, 2009 and 2008 consolidated financial statements and its internal control over financial reporting as at December 31, 2010. 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 at December 31, 2010 and December 31, 2009 and the consolidated statements of earnings and comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2010, and the related notes including a summary of significant accounting policies.

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 Canadian generally accepted accounting principles 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 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 auditors' 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, 2010 and December 31, 2009 and the results of its operations and cash flows for each of the three years in the period ended December 31, 2010 in accordance with Canadian generally accepted accounting principles.

Report on internal control over financial reporting

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2010, based on criteria established in Internal Control - Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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Management's responsibility for internal control over financial reporting

The company's 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.

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 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 Canadian 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 Canadian 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, 2010 based on criteria established in Internal Control – Integrated Framework issued by COSO.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada
February 18, 2011

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CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, ($ millions, except per share amounts)		2010	2009	2008
Gross Revenues	*(Note 1)*	**13,422**	11,790	18,103
Less: Royalties	*(Note 1)*	**449**	273	533
Net Revenues		**12,973**	11,517	17,570
Expenses	*(Note 1)*			
Production and mineral taxes		**34**	44	80
Transportation and blending		**1,065**	760	1,021
Operating		**1,302**	1,312	1,292
Purchased product		**7,549**	5,910	10,341
Depreciation, depletion and amortization		**1,310**	1,527	1,397
General and administrative		**251**	211	171
Interest, net	*(Note 8)*	**279**	244	233
Accretion of asset retirement obligation	*(Note 16)*	**75**	45	40
Foreign exchange (gain) loss, net	*(Note 9)*	**(51)**	304	(308)
(Gain) loss on divestiture of assets		**9**	-	-
Other (income) loss, net	*(Note 6)*	**(13)**	(2)	3
		11,810	10,355	14,270
Earnings Before Income Tax		**1,163**	1,162	3,300
Income tax expense	*(Note 10)*	**170**	344	774
Net Earnings		**993**	818	2,526
Other Comprehensive Income (Loss), Net of Tax				
Foreign currency translation adjustment		**(13)**	(238)	347
Comprehensive Income		**980**	580	2,873
Net Earnings per Common Share	*(Note 22)*			
Basic		**1.32**	1.09	3.37
Diluted		**1.32**	1.09	3.36

See accompanying Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEETS

As at December 31, ($ millions)	2010	2009
Assets		
Current Assets		
Cash and cash equivalents	**300**	155

Accounts receivable and accrued revenues		**1,055**	978
Income tax receivable		**31**	40
Current portion of Partnership Contribution Receivable	*(Note 11)*	**346**	345
Risk management	*(Note 21)*	**163**	60
Inventories	*(Note 12)*	**880**	875
		2,775	2,453
Assets Held for Sale	*(Note 6)*	**65**	-
Property, Plant and Equipment, net	*(Notes 1, 13)*	**15,530**	15,214
Partnership Contribution Receivable	*(Note 11)*	**2,145**	2,621
Risk Management	*(Note 21)*	**43**	1
Other Assets	*(Note 14)*	**391**	320
Goodwill	*(Note 1)*	**1,146**	1,146
		22,095	21,755
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**1,825**	1,574
Income tax payable		**154**	-
Current portion of Partnership Contribution Payable	*(Note 11)*	**343**	340
Risk management	*(Note 21)*	**163**	70
		2,485	1,984
Liabilities Related to Assets Held for Sale	*(Note 6)*	**7**	-
Long-Term Debt	*(Note 15)*	**3,432**	3,656
Partnership Contribution Payable	*(Note 11)*	**2,176**	2,650
Risk Management	*(Note 21)*	**10**	4
Asset Retirement Obligation	*(Note 16)*	**1,213**	1,147
Other Liabilities	*(Note 17)*	**346**	239
Future Income Taxes	*(Note 10)*	**2,404**	2,467
		12,073	12,147
Commitments and Contingencies	*(Note 23)*		
Shareholders' Equity	*(Note 18)*	**10,022**	9,608
		22,095	21,755

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 18)*	Paid in Surplus *(Note 18)*	Retained Earnings	AOCI*	Owner's Net Investment *(Note 18)*	Total
Balance as at December 31, 2007	-	-	-	(123)	8,035	7,912
Net earnings	-	-	-	-	2,526	2,526
Net distribution to owner	-	-	-	-	(1,297)	(1,297)
Other comprehensive income (loss)	-	-	-	347	-	347
Balance as at December 31, 2008	-	-	-	224	9,264	9,488
Net earnings	-	-	-	-	773	773
Net distribution to owner	-	-	-	-	(302)	(302)
Other comprehensive income (loss)	-	-	-	(212)	-	(212)
Owner's Net Investment at Arrangement date – November 30, 2009	-	-	-	12	9,735	9,747
Issuance of common stock in connection with the Arrangement	3,680	-	-	-	(3,680)	-
Reclassification of owner's net investment to paid in surplus in connection with the Arrangement	-	6,055	-	-	(6,055)	-
Net earnings – December 1 to December 31	-	-	45	-	-	45
Dividends on common shares	-	(159)	-	-	-	(159)
Common shares issued under option plans	1	-	-	-	-	1
Other comprehensive income (loss)	-	-	-	(26)	-	(26)
Balance as at December 31, 2009	3,681	5,896	45	(14)	-	9,608
Net earnings	-	-	993	-	-	993
Common shares issued under option plans	35	-	-	-	-	35
Dividends on common shares	-	-	(601)	-	-	(601)
Other comprehensive income (loss)	-	-	-	(13)	-	(13)
Balance as at December 31, 2010	**3,716**	**5,896**	**437**	**(27)**	**-**	**10,022**

*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)		2010	2009	2008
Operating Activities				
Net earnings		**993**	818	2,526
Depreciation, depletion and amortization		**1,310**	1,527	1,397
Future income taxes (recovery)	*(Note 10)*	**88**	(590)	405
Unrealized (gain) loss on risk management	*(Note 21)*	**(46)**	698	(899)
Unrealized foreign exchange (gain) loss	*(Note 9)*	**(69)**	327	(317)
Accretion of asset retirement obligation	*(Note 16)*	**75**	45	40
(Gain) loss on divestiture of assets		**9**	-	-
Other		**55**	20	(37)
Net change in other assets and liabilities		**(55)**	(26)	(92)
Net change in non-cash working capital		**234**	220	202
Cash From Operating Activities		**2,594**	3,039	3,225
Investing Activities				
Capital expenditures	*(Note 1)*	**(2,208)**	(2,165)	(2,204)
Proceeds from divestitures	*(Note 7)*	**309**	222	48
Net change in other assets		**4**	(25)	(49)
Net change in non-cash working capital		**99**	(95)	96
Cash (Used in) Investing Activities		**(1,796)**	(2,063)	(2,109)
Net Cash Provided before Financing Activities		**798**	976	1,116
Financing Activities				
Net issuance (repayment) of revolving long-term debt		**(58)**	(342)	41
Issuance of long-term debt		**-**	204	276
Repayment of long-term debt		**-**	(97)	(247)
Issuance of U.S. Unsecured Notes	*(Note 15)*	**-**	3,718	-
Payment of note payable to Encana	*(Note 15)*	**-**	(3,701)	-
Payment of transition account payable to Encana		**-**	(264)	-
Net financing transactions with Encana		**-**	(302)	(1,297)
Issuance of common shares		**28**	1	-
Dividends on common shares		**(601)**	(159)	-
Other		**-**	(35)	-
Cash (Used in) Financing Activities		**(631)**	(977)	(1,227)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(22)**	(32)	1
Increase (Decrease) in Cash and Cash Equivalents		**145**	(33)	(110)
Cash and Cash Equivalents, Beginning of Year		**155**	188	298
Cash and Cash Equivalents, End of Year		**300**	155	188
Supplemental Cash Flow Information	*(Note 22)*			

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, 2010

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. (“Cenovus” or the “Company”) is 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.”).

The Company is headquartered in Calgary, Alberta and its Common Shares are listed on the Toronto and New York stock exchanges. Information on the Company’s background and the basis of presentation for these financial statements are found in Note 2.

The Company’s operating and reportable segments are as follows:

- **Upstream,** which includes Cenovus’s development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
  - **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 oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated

U.S. public company and operated by Cenovus.

- **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.

- **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 or losses recorded on derivative financial instruments 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 operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location. Capital expenditures, goodwill, sales information and information relating to Cenovus's major customers are summarized at the end of the note.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations - Segment and Operational Information

	Oil Sands			Conventional			Total Upstream		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,719**	2,277	2,558	**2,539**	3,369	4,130	**5,258**	5,646	6,688
Less: Royalties	**279**	135	246	**170**	138	287	**449**	273	533
Net Revenues	**2,440**	2,142	2,312	**2,369**	3,231	3,843	**4,809**	5,373	6,155
Expenses									
Production and mineral taxes	**-**	1	2	**34**	43	78	**34**	44	80
Transportation and blending	**935**	628	791	**130**	132	230	**1,065**	760	1,021
Operating	**369**	332	335	**441**	416	427	**810**	748	762
Purchased product	**-**	-	-	**-**	-	-	**-**	-	-
	1,136	1,181	1,184	**1,764**	2,640	3,108	**2,900**	3,821	4,292
Depreciation, depletion and amortization							**1,039**	1,250	1,179
Segment Income (Loss)							**1,861**	2,571	3,113
Balances as at December 31,									
Property, Plant & Equipment							**10,196**	10,095	9,949
Goodwill							**1,146**	1,146	1,146
Total Assets							**14,543**	14,921	15,466

	Refining and Marketing			Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**8,228**	6,922	10,684	**(64)**	(778)	731	**13,422**	11,790	18,103
Less: Royalties	**-**	-	-	**-**	-	-	**449**	273	533
Net Revenues	**8,228**	6,922	10,684	**(64)**	(778)	731	**12,973**	11,517	17,570
Expenses									
Production and mineral taxes	**-**	-	-	**-**	-	-	**34**	44	80
Transportation and blending	**-**	-	-	**-**	-	-	**1,065**	760	1,021
Operating	**489**	534	543	**3**	30	(13)	**1,302**	1,312	1,292
Purchased product	**7,664**	6,020	10,500	**(115)**	(110)	(159)	**7,549**	5,910	10,341
	75	368	(359)	**48**	(698)	903	**3,023**	3,491	4,836
Depreciation, depletion and amortization	**239**	232	205	**32**	45	13	**1,310**	1,527	1,397
Segment Income (Loss)	**(164)**	136	(564)	**16**	(743)	890	**1,713**	1,964	3,439
General and Administrative				**251**	211	171	**251**	211	171
Interest, net				**279**	244	233	**279**	244	233
Accretion of asset retirement obligation				**75**	45	40	**75**	45	40
Foreign exchange (gain) loss, net				**(51)**	304	(308)	**(51)**	304	(308)
(Gain) loss on divestiture of assets				**9**	-	-	**9**	-	-
Other (income) loss, net				**(13)**	(2)	3	**(13)**	(2)	3
				550	802	139	**550**	802	139
Earnings Before Income Tax							**1,163**	1,162	3,300
Income tax expense							**170**	344	774
Net Earnings							**993**	818	2,526
Balances as at December 31,									
Property, Plant & Equipment	**5,188**	5,003	4,967	**146**	116	98	**15,530**	15,214	15,014

Goodwill	**-**	-	-	**-**	-	-	**1,146**	1,146	1,146
Total Assets	**6,714**	6,404	5,964	**838**	430	1,184	**22,095**	21,755	22,614

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Product and Operational Information

	Crude Oil & NGLs								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,603**	2,056	2,262	**1,220**	1,161	1,606	**3,823**	3,217	3,868
Less: Royalties	**276**	129	178	**153**	119	208	**429**	248	386
Net Revenues	**2,327**	1,927	2,084	**1,067**	1,042	1,398	**3,394**	2,969	3,482
Expenses									
Production and mineral taxes	**-**	1	2	**28**	28	40	**28**	29	42
Transportation and blending	**934**	626	784	**86**	87	154	**1,020**	713	938
Operating	**341**	298	279	**202**	174	171	**543**	472	450
Operating Cash Flow	**1,052**	1,002	1,019	**751**	753	1,033	**1,803**	1,755	2,052

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**102**	214	278	**1,306**	2,196	2,512	**1,408**	2,410	2,790
Less: Royalties	**1**	6	68	**17**	19	79	**18**	25	147
Net Revenues	**101**	208	210	**1,289**	2,177	2,433	**1,390**	2,385	2,643
Expenses									
Production and mineral taxes	**-**	-	-	**6**	15	38	**6**	15	38
Transportation and blending	**1**	2	7	**44**	45	76	**45**	47	83
Operating	**23**	25	43	**235**	237	252	**258**	262	295
Operating Cash Flow	**77**	181	160	**1,004**	1,880	2,067	**1,081**	2,061	2,227

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**14**	7	18	**13**	12	12	**27**	19	30
Less: Royalties	**2**	-	-	**-**	-	-	**2**	-	-
Net Revenues	**12**	7	18	**13**	12	12	**25**	19	30
Expenses									
Production and mineral taxes	**-**	-	-	**-**	-	-	**-**	-	-
Transportation and blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**5**	9	13	**4**	5	4	**9**	14	17
Operating Cash Flow	**7**	(2)	5	**9**	7	8	**16**	5	13

	Total								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**2,719**	2,277	2,558	**2,539**	3,369	4,130	**5,258**	5,646	6,688
Less: Royalties	**279**	135	246	**170**	138	287	**449**	273	533
Net Revenues	**2,440**	2,142	2,312	**2,369**	3,231	3,843	**4,809**	5,373	6,155
Expenses									
Production and mineral taxes	**-**	1	2	**34**	43	78	**34**	44	80
Transportation and blending	**935**	628	791	**130**	132	230	**1,065**	760	1,021
Operating	**369**	332	335	**441**	416	427	**810**	748	762
Operating Cash Flow	**1,136**	1,181	1,184	**1,764**	2,640	3,108	**2,900**	3,821	4,292

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Geographic Information

The Refining and Marketing segment operates in both Canada and the United States. Both of Cenovus's refining facilities are located and carry on business in the United States. 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 United States are considered to be export sales undertaken by a Canadian business.

	Refining and Marketing								
	Canada (Marketing)			United States (Refining)			Total		
For the years ended December 31,	**2010**	2009	2008	**2010**	2009	2008	**2010**	2009	2008
Gross Revenues	**1,604**	965	1,211	**6,624**	5,957	9,473	**8,228**	6,922	10,684
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
Net Revenues	**1,604**	965	1,211	**6,624**	5,957	9,473	**8,228**	6,922	10,684
Expenses									
Operating	**17**	17	20	**472**	517	523	**489**	534	543
Purchased product	**1,579**	938	1,184	**6,085**	5,082	9,316	**7,664**	6,020	10,500
Operating Cash Flow	**8**	10	7	**67**	358	(366)	**75**	368	(359)
Depreciation, depletion and amortization	**10**	12	4	**229**	220	201	**239**	232	205
Segment Income (Loss)	**(2)**	(2)	3	**(162)**	138	(567)	**(164)**	136	(564)

Capital Expenditures

For the years ended December 31,	**2010**	2009	2008
Capital			
Oil Sands	**867**	629	758
Conventional	**523**	466	848
Upstream	**1,390**	1,095	1,606
Refining and Marketing	**656**	1,033	539
Corporate	**76**	34	59
	2,122	2,162	2,204
Acquisition Capital			
Oil Sands	**25**	-	-
Conventional	**23**	3	-
Refining and Marketing	**38**	-	-
Total	**2,208**	2,165	2,204

In addition to the above, in 2009 Cenovus acquired strategic bitumen lands in exchange for certain non-core holdings.

Goodwill Additions

There were no additions to goodwill during 2010, 2009 or 2008.

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada delivered to customers outside of Canada were $646 million (2009–$618 million; 2008–$1,388 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2010, Cenovus had two customers (2009–two; 2008–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 $7,671 million (2009–$6,389 million; 2008–$9,619 million).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

2. BACKGROUND & BASIS OF PRESENTATION

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. The Company's functional currency is Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

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. Common shares of Cenovus began trading on a "when issued" basis on the Toronto ("TSX") and New York ("NYSE") stock exchanges on November 2, 2009. Regular trading of the Cenovus shares began on the TSX on December 3, 2009 and on the NYSE on December 9, 2009.

Up until the completion of the Arrangement, Encana was considered a related party due to its parent-subsidiary relationship with the Cenovus entities. However, subsequent to the Arrangement, Encana is no longer a related party as defined by the CICA Handbook Section 3840 – Related Party Transactions.

Basis of presentation / Carve-out financial information

The results for the year ended December 31, 2010 and the one month period from December 1 to December 31, 2009 represent the Company's operations,

cash flow and financial position as a stand-alone entity. The results for the periods prior to the Arrangement, being from January 1 to November 30, 2009 and January 1 to December 31, 2008 have been prepared on a "carve-out" accounting basis whereby the results 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.

As the Company operated as part of Encana and was not a stand-alone entity prior to November 30, 2009, the historical Consolidated Financial Statements include allocations of certain Encana revenues, expenses, assets and liabilities, including the items described below.

The operating results of Cenovus were specifically identified based on Encana's divisional organization. Certain other expenses presented in the Consolidated Statements of Earnings and Comprehensive Income represent allocations and estimates of the cost of services incurred by Encana. These allocations and estimates include unrealized mark-to-market gains and losses, general and administrative costs, net interest, foreign exchange gains and losses and income tax expenses. The majority of the assets and liabilities of Cenovus were identified based on the divisional structure, with the most significant exceptions being property, plant and equipment ("PP&E"), income taxes payable and long-term debt.

Refining, crude oil and natural gas marketing and corporate depreciation, depletion and amortization were specifically identified based on Encana's divisional structure where possible. Depletion related to upstream properties was allocated to Cenovus based on the related production volumes utilizing the depletion rate calculated for Encana's consolidated Canadian cost centre.

Mark-to-market gains and losses resulting from derivative financial instruments entered into by Encana were allocated to Cenovus based on the related product volumes.

Salaries, benefits, pension, long-term incentives and other post-employment benefits costs, assets and liabilities were allocated to Cenovus based on Management's best estimate of how services were historically provided by existing employees. Costs, assets and liabilities associated with retired employees remained with Encana.

Net interest expense was calculated primarily using the debt balance allocated to Cenovus.

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2. BACKGROUND & BASIS OF PRESENTATION (continued)

Income taxes were recorded as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction.

The calculation of income taxes is based on a number of assumptions, allocations and estimates, including those used to prepare the Cenovus Carve-out Consolidated Financial Statements. Prior to the Arrangement, Cenovus's tax pools were allocated for the Canadian cost centre based on the same allocation method used to determine PP&E for carve-out purposes.

PP&E related to upstream oil and gas activities are accounted for by Cenovus using the full cost method of accounting. PP&E related to upstream oil and gas activities was determined based on an allocation process which used the ratio of future net revenue, discounted at 10 percent, of the respective divisions of Encana to the future net revenue, discounted at 10 percent, of all proved properties in Canada at December 31, 2008. Future net revenue was the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves.

Goodwill was allocated to Cenovus based on the properties associated with the former business combinations on which it arose.

For the purpose of preparing the Carve-out Consolidated Financial Statements, it was determined that Cenovus should maintain approximately the same Debt to Capitalization ratio as consolidated Encana based on U.S. dollar amounts. As a result, prior to the Arrangement, debt was allocated to Cenovus based on this ratio, which was calculated using U.S. dollars. Debt is defined as the current and long-term portions of Long-term Debt. Capitalization is not a term that has a prescribed meaning under generally accepted accounting principles ("non-GAAP") and is a measure defined as Debt plus Shareholders' Equity.

Management believes the assumptions underlying the Cenovus Carve-out Consolidated Financial Statements are reasonable. However, the Cenovus Consolidated Financial Statements herein may not reflect Cenovus's financial position, results of operations, and cash flows had Cenovus been a stand-alone company during the periods presented or what Cenovus's operations, financial position, and cash flows will be in the future. Encana's direct investment in Cenovus is shown as Net Investment in place of Shareholders' Equity because a direct ownership by shareholders in Cenovus did not exist prior to November 30, 2009. Encana's investment includes the accumulated net earnings, other comprehensive income and net cash distributions to Encana.

In the opinion of Management, the Consolidated and the historical Carve-out Consolidated Financial Statements reflect all adjustments (including normal recurring adjustments) necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

3. CHANGE IN REPORTING CURRENCY

As a result of the Arrangement, Cenovus reported its results in U.S. dollars for the preparation of its December 31, 2009 consolidated financial statements as this was the reporting currency used by Encana. Effective January 1, 2010, the Company changed its reporting currency to Canadian dollars. The change in reporting currency is to better reflect the business of Cenovus, and it allows for increased comparability to the Company's peers. In implementing this change, the Company has followed the requirements of the Canadian Institute of Chartered Accountants ("CICA") Emerging Issues Committee ("EIC") Abstract 130 ("EIC-130"), "Translation Method When the Reporting Currency Differs from the Measurement Currency or there is a Change in the Reporting Currency."

With the change in reporting currency, all comparative financial information has been restated from U.S. dollars to Canadian dollars to reflect the Company's consolidated financial statements as if they had been historically reported in Canadian dollars.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries and are presented in accordance with Canadian GAAP. Information prepared in accordance with GAAP in the United States is included in Note 24.

Investments in jointly controlled partnerships and unincorporated joint ventures 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 accounts.

B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included in Accumulated Other Comprehensive Income ("AOCI") as a separate component of Shareholders' Equity.

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 Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements in conformity with Canadian GAAP 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. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of crude oil and natural gas reserves, future costs required to develop those reserves and future cash flows. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

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.

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.

The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. As such, income taxes are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when title passes from the Company to its customer. Realized gains and losses from crude oil and natural gas commodity price risk management activities are recorded in revenue when the product is sold.

Revenues and purchased product are recorded on a gross basis when the title to product passes and the risks and rewards of ownership have been transferred. 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.

Unrealized gains and losses from natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-

to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

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

F) Transportation and Blending Costs

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.

G) Employee Benefit Plans

Accruals for obligations under the employee 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 benefit 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 the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is calculated on a straight-line basis over a period covering the expected average remaining service lives of employees 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.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

H) Income Taxes

Cenovus follows the liability method of accounting for income taxes, where future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future 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.

I) 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, without tandem stock appreciation rights attached, were exercised or other contracts expected to result in the issuance of common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem stock appreciation rights attached are used to repurchase common shares at the average market price.

J) Cash and Cash Equivalents

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

K) Inventories

Product inventories, including petroleum and refined products, are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis.

L) Property, Plant and Equipment

Upstream

Crude oil and natural gas properties are accounted for in accordance with the CICA guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, the exploration for, and the development of bitumen, crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, natural gas is converted to oil on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is dete rmined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to

depreciation, depletion and amortization.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test.

Refining

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 and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over the estimated service lives of each component of the refining facilities.

An impairment loss is recognized on refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the carrying amount exceeds the fair value.

Other

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Assets under construction are not subject to depreciation until put into use.

M) Capitalization of Costs

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.

N) Amortization of Other Assets

Items included in Other Assets are amortized, where applicable, on a straight-line basis over the estimated useful lives of the assets.

O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as a reporting unit. To assess impairment, the fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of go odwill is the impairment amount.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

P) Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheets when incurred and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where Cenovus will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing plants, and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or

amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statements of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) Stock-Based Compensation

Obligations for payments, cash or common shares, under Cenovus's stock option, performance share unit and deferred share unit plans are accrued using the intrinsic method as compensation cost over the vesting period. Fluctuations in the price of Cenovus's common shares change the accrued compensation cost and are recognized when they occur.

Encana replacement stock options with tandem stock appreciation rights attached held by Cenovus employees are accrued using the fair value method. The fair value is recognized as compensation cost over the vesting period. Fluctuations in the fair value of the rights change the accrued compensation cost and are recognized when they occur.

R) Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities".

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held-for-trading" and are measured at fair value. Accounts receivable and accrued revenues and the Partnership Contribution Receivable and partner loans receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the Partnership Contribution Payable and partner loans payable and long-term debt are designated as "other financial liabilities". Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt and amortized using the effective interest method.

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4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Derivative Financial Instruments

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. Realized gains or losses from financial derivatives related to crude oil and natural gas commodity prices are recognized in crude oil and natural gas revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. 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 and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. 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 transact ion.

S) Reclassification

In addition to the restatement required due to the changes in operating segments (see Note 1), certain information provided for prior years has been reclassified to conform to the presentation adopted in 2010.

T) Recent Accounting Pronouncements

Beginning with the three month period ending March 31, 2011, Cenovus is required to report its results in accordance with International Financial Reporting Standards ("IFRS"). Cenovus has developed a detailed changeover plan to complete the transition to IFRS. The plan includes the preparation of required comparative information for 2010, given that the IFRS date of transition was January 1, 2010. The Company is on schedule with its plan and is continuing to assess the potential impact of the adoption of IFRS on its Consolidated Financial Statements.

5. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Business Combinations

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations," which replaces CICA Handbook Section 1581 of the same name. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the Statement of Earnings. This accounting policy was applied to the November 1, 2010 purchase of the marine terminal facilities disclosed in Note 6.

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5. CHANGES IN ACCOUNTING POLICIES AND PRACTICES (continued)

Consolidated Financial Statements and Non-controlling Interests

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements." Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest to be classified as a separate component of equity. In addition, net earnings, and components of other comprehensive income are attributed to both the parent and non-controlling interest. The early adoption of these standards did not have a material impact on the Company's Consolidated Financial Statements for the year ended December 31, 2010. These standards along with CICA Handbook Section 1582 above are converged with IFRS (see Note 4).

6. ASSETS AND LIABILITIES HELD FOR SALE

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.

Cenovus intends to sell the facilities as soon as practicable. As a result, the net assets acquired have been recorded at estimated fair value less costs to sell, and have been classified as held for sale. These assets are 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 table below represents the purchase cost and the preliminary allocation to the assets and liabilities. The gain has been recorded in other income.

Cash consideration	38
Fair value of Liabilities assumed	
Asset retirement obligation	5
Future income taxes	4
Total Purchase Price and Liabilities Assumed	47
Estimated Fair Value of Assets acquired	
Property, Plant and Equipment	59
Bargain Purchase Gain	12

As at December 31, 2010 the assets and liabilities classified as held for sale consists of the following:

	December 31, 2010
Assets Held for Sale	
Property, plant and equipment	65
Liabilities Related to Assets Held for Sale	
Asset retirement obligation	5
Future income taxes	2
	7

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7. DIVESTITURES

For the years ended December 31,	2010	2009	2008
Oil Sands	**81**	89	8
Conventional	**221**	130	40
Corporate	**7**	3	-
Cash Proceeds	**309**	222	48

8. INTEREST, NET

For the years ended December 31,	2010	2009	2008
Interest Expense–Long-Term Debt	**227**	211	205
Interest Expense–Other	**196**	220	228
Interest Income	**(144)**	(187)	(200)
	279	244	233

Interest Expense–Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively (See Note 11).

9. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2010	2009	2008
Unrealized Foreign Exchange (Gain) Loss on translation of:			
U.S. dollar debt issued from Canada	**(182)**	(381)	430
U.S. dollar Partnership Contribution Receivable issued from Canada	**91**	504	(744)
Other	**22**	204	(3)
Unrealized Foreign Exchange (Gain) Loss	**(69)**	327	(317)
Realized Foreign Exchange (Gain) Loss	**18**	(23)	9
	(51)	304	(308)

10. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31,	2010	2009	2008
Current			
Canada	**82**	979	393
United States	**-**	(45)	(24)
Total Current Tax	**82**	934	369
Future Tax	**88**	(590)	405
	170	344	774

Future income tax expense in 2010 includes a tax benefit of $107 million from the recognition of net capital losses expected to be realized against future capital gains. These net capital losses are attributable to an internal restructuring undertaken in 2010. Net capital losses of $415 million, attributable to the restructuring and to realized foreign exchange losses, are unrecognized at December 31, 2010. Recognition is dependent on the level of future capital gains.

Current income tax expense in 2009 includes the incremental tax incurred as a result of certain corporate restructuring transactions which were required to effect the Arrangement.

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10. INCOME TAXES (continued)

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

For the years ended December 31,	2010	2009	2008
Earnings Before Income Tax	**1,163**	1,162	3,300
Canadian Statutory Rate	**28.2%**	29.2%	29.7%
Expected Income Tax	**328**	339	980
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(33)**	(1)	(92)
Non-deductible stock-based compensation	**29**	-	-
Multi-jurisdictional financing	**(93)**	(134)	(135)
Foreign exchange gains not included in net earnings	**28**	58	71
Non-taxable capital (gains) losses	**(9)**	30	(53)

Recognition of capital losses	**(107)**	-	-
Other	**27**	52	3
	170	344	774
Effective Tax Rate	**14.6%**	29.6%	23.5%

The net future income tax liability consists of:

As at December 31,	**2010**	2009
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,534**	2,654
Timing of partnership items	**125**	9
Net foreign exchange gains	**127**	61
Risk management	**55**	17
Other	**55**	1
Future Tax Assets		
Unused tax losses	**(281)**	(242)
Risk management	**(45)**	(33)
Other	**(166)**	-
Net Future Income Tax Liability	**2,404**	2,467

The approximate amounts of tax pools available are as follows:

As at December 31,	**2010**	2009
Canada	**4,239**	3,754
United States	**3,082**	2,637
	7,321	6,391

Included in the above tax pools are $236 million (2009–$491 million) of Canadian non-capital losses which expire no earlier than 2026 and $607 million (2009–$232 million) of U.S. net operating losses which expire no earlier than 2029.

Also included in the above tax pools are $983 million (2009–$51 million) of Canadian net capital losses, available for carry forward to reduce future capital gains.

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11. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In connection with the Arrangement with Encana, 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 consists 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.

In accordance with Canadian GAAP, these entities have been accounted for using the proportionate consolidation method with the results of operations included in the Upstream and Refining and Marketing segments (See Note 1).

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

	2011	2012	2013	2014	2015	Thereafter	**Total**
Partnership Contribution Receivable–US$	348	366	386	407	429	569	**2,505**
Partnership Contribution Receivable-C$ equivalent	346	364	384	405	427	565	**2,491**

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

	2011	2012	2013	2014	2015	Thereafter	**Total**
Partnership Contribution Payable–US$	345	366	388	412	437	584	**2,532**

Partnership Contribution Payable–C$ equivalent	343	364	386	410	435	581	**2,519**

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, 2010 these amounts were $274 million (December 31, 2009–$183 million).

12. INVENTORIES

As at December 31,	2010	2009
Product		
Upstream – Oil Sands	**80**	84
Refining and Marketing	**779**	772
Parts and Supplies	**21**	19
	880	875

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12. INVENTORIES (continued)

As a result of a significant decline in commodity prices in the latter half of 2008, Cenovus recorded a write-down of its product inventory by $186 million from cost to net realizable value at December 31, 2008. Product turnover and the improvement in commodity prices has resulted in all of the 2008 write-down being reversed, $178 million in 2009 and $8 million in 2010.

The total amount of inventories recognized as an expense during the year was $5,997 million (2009–$4,999 million; 2008–$9,322 million).

13. PROPERTY, PLANT AND EQUIPMENT, NET

As at December 31,	2010			2009		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream	**22,691**	**(12,495)**	**10,196**	21,550	(11,455)	10,095
Refining and Marketing	**5,883**	**(695)**	**5,188**	5,537	(534)	5,003
Corporate and Eliminations	**446**	**(300)**	**146**	390	(274)	116
	29,020	**(13,490)**	**15,530**	27,477	(12,263)	15,214

* Depreciation, depletion and amortization

Upstream property, plant and equipment includes internal costs directly related to exploration, development and construction activities of $102 million (2009–$117 million). Costs classified as general and administrative expenses have not been capitalized as part of the capital expenditures.

Costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. Refining assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31,	2010	2009	2008
Upstream	**758**	644	278
Refining and Marketing	**1,673**	1,366	598
	2,431	2,010	876

The Canadian prices used in the ceiling test evaluation of Cenovus's crude oil and natural gas reserves at December 31, 2010 were:

	2011	2012	2013	2014	2015	Average Annual % Change to 2022
WTI (US$/barrel)	85.00	87.70	90.50	93.40	96.30	2%
AECO ($/Mcf)	4.25	4.90	5.40	5.90	6.35	4%
Crude Oil ($/barrel)	64.75	66.32	65.08	66.59	68.71	2%
Natural Gas Liquids ($/barrel)	62.19	66.27	68.94	71.25	73.58	2%
Natural Gas ($/Mcf)	4.05	4.70	5.20	5.70	6.14	4%

During the year ended December 31, 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, the carrying amount of the unit was reduced to zero and an impairment loss of $37 million net to Cenovus, was recorded as additional depreciation, depletion and amortization in the Consolidated Statements of Earnings and Comprehensive Income within the Refining and Marketing segment.

14. OTHER ASSETS

As at December 31,	2010	2009
Partner Loans	**274**	183
Deferred Asset–Refining and Marketing	**99**	121
Deferred Pension Plan and Savings Plan	**11**	9
Other	**7**	7
	391	320

15. LONG-TERM DEBT

As at December 31,	Note	2010	2009
Canadian Dollar Denominated Debt			
Revolving term debt*	A	**-**	32
U.S. Dollar Denominated Debt			
Revolving term debt*	A	**-**	26
Unsecured notes	B	**3,481**	3,663
		3,481	3,689
Total Debt Principal		**3,481**	3,721
Debt Discounts and Transaction Costs	C	**(49)**	(65)
Current Portion of Long-Term Debt	D	**-**	-
		3,432	3,656

* Revolving term debt includes commercial paper, 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, 2010 was 5.8 percent (2009–5.5 percent).

A) Revolving Term Debt

At December 31, 2010, Cenovus had in place a committed credit facility in the amount of C$2,500 million or its equivalent amount in U.S. dollars. The committed credit facility matures on November 30, 2014 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, 2010, no amounts were drawn on Cenovus's committed bank credit facility (2009 – $58 million).

B) Unsecured Notes

In conjunction with the Arrangement, on September 18, 2009 Cenovus completed a private offering of senior unsecured notes of an aggregate principal amount of US$3,500 million. The notes were disclosed on Cenovus's Consolidated Balance Sheets as a long term liability, net of financing costs as at September 30, 2009. The net proceeds of $3,718 million were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement. Cenovus placed an additional $162 million into the escrow account so that the total escrowed funds of $3,880 million would be sufficient to pay the special mandatory redemption price for the notes if the Arrangement did not proceed. Upon completion of the Arrangement, funds were released from escrow and the proceeds of the notes were used to pay the note payable to Encana of US$3,500 million as part of the Arrangement. On November 30, 2009 these notes became the direct, unsecured obligations of Cenovus. In 2010, substantially all of these notes were exchanged for notes registered under the Securities Act of 1933 with the same terms and conditions as the original issued notes.

15. LONG-TERM DEBT (continued)

	US$ Principal Amount	2010	2009
4.50% due September 15, 2014	**800**	**796**	837
5.70% due October 15, 2019	**1,300**	**1,293**	1,361
6.75% due November 15, 2039	**1,400**	**1,392**	1,465
	3,500	**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, 2010, 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, 2010, no notes have been issued under this U.S. prospectus. The shelf prospectus expires in August 2012.

At December 31, 2010, 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 are recorded within long-term debt and are being amortized using the effective interest method. During 2010, no transaction costs were recorded within long term debt (2009–$70 million).

D) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	Total C$ Equivalent
2011	-	-	-
2012	-	-	-
2013	-	-	-
2014	800	-	796
2015	-	-	-
Thereafter	2,700	-	2,685
	3,500	-	3,481

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16. ASSET RETIREMENT OBLIGATION

The aggregate carrying amount of the obligation associated with the retirement of upstream oil and gas assets and refining facilities is as follows:

As at December 31,	2010	2009
Asset Retirement Obligation, Beginning of Year	**1,147**	793
Liabilities Incurred	**44**	6
Liabilities Settled	**(33)**	(38)
Liabilities Divested	**(88)**	(10)
Change in Estimated Future Cash Flows	**69**	357
Accretion Expense	**75**	45
Foreign Currency Translation	**(1)**	(6)
Asset Retirement Obligation, End of Year	**1,213**	1,147

The total undiscounted amount of estimated cash flows required to settle the obligation is $6,093 million (2009–$5,683 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.09 percent (2009–6.23 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general resources at that time.

17. OTHER LIABILITIES

As at December 31,	2010	2009
Partner Loans	**274**	183
Deferred Revenue	**37**	40
Other	**35**	16
	346	239

18. 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.

Issued and Outstanding

As at December 31,	2010		2009	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount

Outstanding, Beginning of Year	**751,309**	**3,681**	-	-
Common Shares Issued Pursuant to the Arrangement	**-**	**-**	751,273	3,680
Common Shares Issued under Stock Option Plans	**1,366**	**35**	36	1
Outstanding, End of Year	**752,675**	**3,716**	751,309	3,681

To determine Cenovus's share capital amount at the time of the Arrangement, Encana's stated capital immediately prior to the Arrangement was split based on the relative fair market values of the Encana and Cenovus Common Shares at the time of the initial exchange. Cenovus's share capital amount was deducted from Encana's net investment with the remaining $6,055 million reclassified as Paid in Surplus.

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18. SHARE CAPITAL (continued)

At December 31, 2010, there were 26 million (2009–24 million) Common Shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at December 31, 2010.

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.

Net Investment

For periods prior to the Arrangement, Encana's net investment in the operations of Cenovus is presented as total Net Investment in the Consolidated Financial Statements. Total Net Investment consists of Owner's Net Investment and AOCI.

Stock-Based Compensation

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 February 17, 2010 or later expire after seven years.

All options issued by the Company under the Employee Stock Option Plan 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 right. The tandem stock appreciation rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this note, options with associated tandem stock appreciation rights are referred to as "TSARs".

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 2, 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 Optio n Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

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18. SHARE CAPITAL (continued)

TSARs Held by Cenovus Employees

The following tables summarize the information related to the TSARs held by Cenovus employees as at December 31, 2010:

As at December 31, 2010				
(thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,402	8,053	16,455	27.52
Granted	6,087	-	6,087	26.54
Exercised for cash payment	(1,099)	(77)	(1,176)	21.32
Exercised as options for shares	(948)	(109)	(1,057)	23.52
Forfeited	(398)	(794)	(1,192)	28.55
Outstanding, End of Year	12,044	7,073	19,117	27.75
Exercisable, End of Year	4,154	3,580	7,734	28.07

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	1,198	-	1,198	0.25	22.96	1,172	-	1,172	22.94
25.00 to 29.99	8,925	4,694	13,619	3.99	26.47	1,818	2,351	4,169	26.59
30.00 to 34.99	1,733	2,379	4,112	2.19	32.87	1,051	1,229	2,280	32.86
35.00 to 39.99	119	-	119	2.44	37.22	72	-	72	37.22
40.00 to 44.99	67	-	67	2.45	43.23	40	-	40	43.23
45.00 to 49.99	2	-	2	2.39	45.56	1	-	1	45.56
	12,044	7,073	19,117	3.35	27.75	4,154	3,580	7,734	28.07

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.

Cenovus has recorded a liability of $123 million (2009–$84 million) in the Consolidated Balance Sheets for Cenovus Replacement TSARs held by Encana employees using the fair value method, with an offsetting accounts receivable from Encana. The fair value of each Cenovus Replacement TSAR held by Encana employees was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	1.70%
Dividend Yield	2.40%
Volatility	23.99%
Cenovus's Common Share Price	$33.28

The following tables summarize information related to the Cenovus Replacement TSARs held by Encana employees as at December 31, 2010:

As at December 31, 2010				
(thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,482	10,463	22,945	27.14
Exercised for cash payment	(3,847)	(411)	(4,258)	22.67
Exercised as options for shares	(105)	(1)	(106)	19.44
Forfeited	(316)	(1,111)	(1,427)	28.80
Outstanding, End of Year	8,214	8,940	17,154	28.16
Exercisable, End of Year	5,977	4,828	10,805	27.88

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18. SHARE CAPITAL (continued)

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	1,658	-	1,658	0.17	22.95	1,650	-	1,650	22.95
25.00 to 29.99	4,116	6,107	10,223	2.19	26.49	2,711	3,368	6,079	26.63
30.00 to 34.99	2,271	2,833	5,104	2.09	32.83	1,515	1,460	2,975	32.74
35.00 to 39.99	90	-	90	2.44	37.24	54	-	54	37.24
40.00 to 44.99	77	-	77	2.44	42.81	46	-	46	42.81
45.00 to 49.99	2	-	2	2.39	45.56	1	-	1	45.56
	8,214	8,940	17,154	1.97	28.16	5,977	4,828	10,805	27.88

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 $24 million (2009–$70 million) in the Consolidated Balance Sheets for Encana Replacement TSARs held by Cenovus's employees using the fair value method. The fair value of each Encana Replacement TSAR was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	1.70%
Dividend Yield	2.74%
Volatility	23.57%
Encana's Common Share Price	$29.09

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees as at December 31, 2010:

As at December 31, 2010				
(thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	8,305	8,052	16,357	30.46
Exercised for cash payment	(1,568)	(148)	(1,716)	24.43
Exercised as options for Encana shares	(94)	-	(94)	21.47
Forfeited	(214)	(806)	(1,020)	31.98
Outstanding, End of Year	6,429	7,098	13,527	31.17
Exercisable, End of Year	4,461	3,605	8,066	30.85

(thousands of units)	Outstanding TSARs					Exercisable TSARs			
Range of Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price ($)
20.00 to 24.99	7	-	7	2.75	23.04	4	-	4	23.06
25.00 to 29.99	4,371	4,718	9,089	2.04	28.59	3,127	2,376	5,503	28.30
30.00 to 34.99	312	-	312	1.75	32.61	274	-	274	32.71
35.00 to 39.99	1,597	2,380	3,977	2.13	36.47	971	1,229	2,200	36.47
40.00 to 44.99	74	-	74	2.49	42.28	45	-	45	42.28
45.00 to 49.99	66	-	66	2.46	47.86	39	-	39	47.86
50.00 to 54.99	2	-	2	2.39	50.39	1	-	1	50.39
	6,429	7,098	13,527	2.06	31.17	4,461	3,605	8,066	30.85

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18. SHARE CAPITAL (continued)

B) Performance Share Units

The Company 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 following table summarizes information related to the PSUs held by Cenovus employees as at December 31, 2010:

	Outstanding PSUs (thousands)
Outstanding, Beginning of Year	-
Granted	1,252
Cancelled	(35)
Units in Lieu of Dividends	35
Outstanding, End of Year	1,252

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 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

Pursuant to the terms of the Arrangement, Encana DSUs credited to directors, officers and employees of Cenovus were exchanged for Cenovus DSUs. The fair value of the Cenovus DSUs credited to each holder was based on the fair market value of Cenovus Common Shares relative to Encana Common Shares prior to the effective date of the Arrangement.

The following table summarizes information related to the DSUs held by Cenovus directors, officers and employees as at December 31, 2010:

	Outstanding DSUs (thousands)
Outstanding, Beginning of Year	**768**
Granted	**65**
Granted from Annual Bonus Awards	**81**
Units in Lieu of Dividends	**26**
Outstanding, End of Year	**940**

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18. SHARE CAPITAL (continued)

D) 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:

	2010	2009*	2008
TSARs held by Cenovus employees	**52**	(2)	-
Encana Replacement TSARs held by Cenovus employees	**(23)**	32	-
Performance Share Units	**13**	-	-
Deferred Share Units	**9**	-	-
Total stock-based compensation expense (recovery)	**51**	30	-

*2009 represents one month of compensation expense incurred under the Cenovus plan post Arrangement.

Included in the financial information prior to the Arrangement, the Company recorded compensation expense (recovery) for the following Encana plans:

	2010	2009	2008
Encana TSARs	**-**	4	(5)
Encana DSUs	**-**	3	1
Total stock-based compensation expense (recovery)	-	7	(4)

19. CAPITAL STRUCTURE

Cenovus's capital structure is comprised of Shareholders' Equity plus Debt. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and short-term 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 the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent.

As at December 31,	2010	2009
Debt	**3,432**	3,656
Shareholders' Equity	**10,022**	9,608
Total Capitalization	**13,454**	13,264
Debt to Capitalization ratio	**26%**	28%

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19. CAPITAL STRUCTURE (continued)

Cenovus targets a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at December 31,	2010	2009	2008

Debt	**3,432**	3,656	3,719
Net Earnings	**993**	818	2,526
Add (deduct):			
Interest, net	**279**	244	233
Income tax expense	**170**	344	774
Depreciation, depletion and amortization	**1,310**	1,527	1,397
Accretion of asset retirement obligation	**75**	45	40
Foreign exchange (gain) loss, net	**(51)**	304	(308)
(Gain) loss on divestiture of assets	**9**	-	-
Other (income) loss, net	**(13)**	(2)	3
Adjusted EBITDA	**2,772**	3,280	4,665
Debt to Adjusted EBITDA	**1.2x**	1.1x	0.8x

It is Cenovus's intention to maintain an investment grade rating to 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.

Cenovus's capital structure, objectives and targets have remained unchanged since Cenovus's inception. At December 31, 2010, Cenovus is in compliance with all of the terms of its debt agreements.

20. 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 November 30, 2009 and the next required actuarial valuation will be as at December 31, 2012.

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

	Pension Benefits		OPEB	
As at December 31,	**2010**	2009	**2010**	2009
Accrued Benefit Obligation, End of Year	**68**	56	**14**	11
Fair Value of Plan Assets, End of Year	**59**	54	**-**	-
Funded Status–Plan Assets (less) than Benefit Obligation	**(9)**	(2)	**(14)**	(11)
Amounts Not Recognized:				
Unamortized net actuarial (gain) loss	**20**	15	**1**	(1)
Unamortized past service cost	**-**	-	**-**	1
Accrued Benefit Asset (Liability)	**11**	13	**(13)**	(11)

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20. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS (continued)

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

	Pension Benefits		OPEB	
As at December 31,	**2010**	2009	**2010**	2009
Discount Rate	**5.25%**	6.00%	**5.25%**	6.00%
Rate of Compensation Increase	**4.05%**	4.05%	**5.65%**	5.77%

Estimated future payment of pension and other benefits are as follows:

	Pension Benefits	OPEB
2011	1	-
2012	2	-
2013	2	1
2014	3	1
2015	4	1
2016 – 2020	23	9
Total	35	12

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable and partner loans, risk management assets and liabilities, and long-term debt. 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.

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 and partner loans 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 market information. At December 31, 2010, the carrying value of Cenovus's long-term debt accounted for using amortized cost was $3,432 million and the fair value was $3,940 million (December 31, 2009–carrying value–$3,656 million, fair value–$3,964 million).

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement with Encana, 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.

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21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Risk Management Position

As at December 31,	2010	2009
Risk Management		
Current asset	**163**	60
Long-term asset	**43**	1
	206	61
Risk Management		
Current liability	**163**	70
Long-term liability	**10**	4
	173	74
Net Risk Management Asset (Liability)	**33**	(13)

Of the $33 million net risk management asset balance at December 31, 2010, an asset of $41 million relates to the contract with Encana (2009–net liability of $15 million).

Summary of Unrealized Risk Management Positions

As at December 31,	2010			2009		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	**4**	**159**	**(155)**	8	66	(58)
Natural Gas	**202**	**-**	**202**	53	-	53
Power	**-**	**14**	**(14)**	-	8	(8)
Total Fair Value	**206**	**173**	**33**	61	74	(13)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at December 31,	2010	2009
Prices actively quoted	**40**	6
Prices sourced from observable data or market corroboration	**(7)**	(19)
Total Fair Value	**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.

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21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Fair Value of Commodity Price Positions at December 31,2010

As at December 31, 2010	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	28,600 bbls/d	2011	US$85.54/bbl	**(85)**
WTI NYMEX Fixed Price	29,200 bbls/d	2011	C$88.32/bbl	**(58)**
WTI NYMEX Fixed Price	5,000 bbls/d	2012	US$92.44/bbl	**(3)**
WTI NYMEX Fixed Price	3,000 bbls/d	2012	C$93.82/bbl	**(1)**
Other Fixed Price Contracts *		2011		**4**
Other Financial Positions **				**(12)**
Crude Oil Fair Value Position				**(155)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	379 MMcf/d	2011	US$5.70/Mcf	**158**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**41**
AECO Fixed Price	80 MMcf/d	2012	C$4.49/Mcf	**-**
Other Fixed Price Contracts *		2011-2013		**3**
Natural Gas Fair Value Position				**202**
Power Purchase Contracts				
Power Fair Value Position				**(14)**

* Cenovus has entered into fixed priced swaps to protect against widening price differentials between production areas in Canada and various sales points.
** Other financial positions are part of ongoing operations to market the Company's production.

Earnings Impact of Realized and Unrealized Gains (Losses) on RiskManagement Positions

	Realized Gain (Loss)		
For the years ended December 31,	**2010**	2009	2008
Gross Revenues	**272**	1,154	(305)
Less: Royalties	**-**	-	-
Net Revenues	**272**	1,154	(305)
Operating Expenses and Other	**6**	(38)	31
Gain (Loss) on Risk Management	**278**	1,116	(274)

	Unrealized Gain (Loss)		
For the years ended December 31,	**2010**	2009	2008
Gross Revenues	**60**	(668)	890
Less: Royalties	**-**	-	-
Net Revenues	**60**	(668)	890
Operating Expenses and Other	**(14)**	(30)	9
Gain (Loss) on Risk Management	**46**	(698)	899

Reconciliation of Unrealized Risk Management Positions

For the years ended December 31,	2010		2009	2008
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**(13)**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**324**	**324**	418	625
Fair Value of Contracts Realized During the Year	**(278)**	**(278)**	(1,116)	274
Fair Value of Contracts, End of Year	**33**	**46**	(698)	899

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21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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. When assessing the potential impact of these commodity price changes, Management believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax at December 31, 2010 as follows:

	10% Price Increase	10% Price Decrease
Crude oil price	**(227)**	**227**
Natural gas price	**(104)**	**104**
Power price	**6**	**(6)**

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 financial instruments for speculative purposes.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending with fixed price swaps. To help protect against widening crude oil 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.

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 two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage 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, 2010, over 92 percent (2009 – 98 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade co unterparties.

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21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

At December 31, 2010, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (2009–three counterparties, including Encana) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the Partnership Contribution Receivable and the partner loans receivable 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. As disclosed in Note 19, 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, 2010, Cenovus's committed credit facility was fully available. In addition Cenovus had $1,500 million in unused capacity under its Canadian shelf prospectus and US$1,500 million in unused capacity under its U.S. shelf prospectus, the availability of which are dependent on market conditions.

Cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	1,825	-	-	-	**1,825**
Risk Management Liabilities	163	10	-	-	**173**
Long-Term Debt[1][2]	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
(2) No principal repayment until 2014 and thereafter (see Note 15D)

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. Cenovus's functional currency and reporting currency is Canadian dollars. All amounts are reported in Canadian dollars, unless otherwise indicated.

As disclosed in Note 9, 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, 2010, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,525 million at December 31, 2009) and US$2,505 million related to the U.S. dollar Partnership Contribution Receivable (US$2,834 million at December 31, 2009). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $10 million change in foreign exchange (gain) loss at December 31, 2010 (2009–$7 million).

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21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

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, 2010, one hundred percent of the Company's debt was fixed-rate debt and as a result, had interest rates on floating rate debt changed by one percent there would be no impact on net earnings (December 31, 2009–$nil; 2008–$5 million). This assumes the amount of fixed and floating debt remains unchanged from December 31, 2010.

22. SUPPLEMENTARY INFORMATION

A) Per Share Amounts

For the years ended December 31, (millions)	2010	2009	2008
Weighted Average Common Shares Outstanding – Basic	**751.9**	751.0	750.1
Effect of Stock Options and Other Dilutive Securities	**0.8**	0.4	1.7
Weighted Average Common Shares Outstanding – Diluted	**752.7**	751.4	751.8

Since Cenovus's shares were issued pursuant to the Arrangement, the per share amounts disclosed for 2009 and 2008 are based on the number of Encana's Common Shares outstanding.

B) Supplementary Cash Flow Information

For the years ended December 31,	2010	2009	2008
Interest Paid	**423**	426	422
Income Taxes Paid	**62**	1,284	542

Income taxes paid in 2009 includes amounts paid to Encana as a result of the dissolution of a partnership in connection with the Arrangement.

23. 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	2012	2013	2014	2015	Thereafter	Total
Operating Leases (Building Leases)	33	87	88	85	78	1,553	1,924
Pipeline Transportation[1]	107	93	167	167	166	953	1,653
Purchases of Goods and Services	157	23	12	10	7	23	232
Capital Commitments	91	71	4	4	4	14	188
Product Purchases	23	18	18	18	18	7	102
Other Long-Term Commitments	4	2	1	1	-	1	9
Total Payments	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

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23. COMMITMENTS AND CONTINGENCIES (continued)

At December 31, 2010, there were outstanding letters of credit aggregating $23 million issued as security for performance under certain contracts (2009 – $13 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 21.

B) Contingencies

Legal Proceedings

Cenovus is involved in various legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims.

Asset Retirement

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 $1,218 million, including $5 million that has been classified as Liabilities Related to Assets Held for Sale, 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.

24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Cenovus Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP applicable to Cenovus are described in this note. The most notable differences are:

- full cost accounting;
- pensions and other post-employment benefits;
- liability-based stock compensation plans;
- income taxes;
- other comprehensive income; and
- joint venture accounting.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31,	Note 24	2010	2009	2008
Net Earnings–Canadian GAAP		**993**	818	2,526
Increase (Decrease) in Net Earnings Under U.S. GAAP:				
Operating expense	*C ii)*	**9**	4	(13)
Depreciation, depletion and amortization expense	*A, C ii)*	**107**	239	21
General and administrative expense	*C ii)*	**11**	9	(17)
Stock-based compensation expense		**-**	-	1
Income tax expense	*D*	**(87)**	(199)	(138)
Net Earnings–U.S. GAAP		**1,033**	871	2,380

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24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31,	Note 24	2010	2009	2008
Gross Revenues		**13,422**	11,790	18,103
Less: Royalties		**449**	273	533
Net Revenues		**12,973**	11,517	17,570
Expenses				
Production and mineral taxes		**34**	44	80
Transportation and blending		**1,065**	760	1,021
Operating	*C ii)*	**1,293**	1,308	1,305
Purchased product		**7,549**	5,910	10,341
Depreciation, depletion and amortization	*A, C ii)*	**1,203**	1,288	1,376
General and Administrative	*C ii)*	**240**	202	188
Interest, net		**279**	244	233
Accretion of asset retirement obligation		**75**	45	40
Foreign exchange (gain) loss, net		**(51)**	304	(308)
Stock-based compensation–options		**-**	-	(1)
(Gain) loss on divestiture of assets		**9**	-	-
Other (income) loss, net		**(13)**	(2)	3

		11,683	10,103	14,278
Earnings Before Income Tax		**1,290**	1,414	3,292
Income tax expense	*D*	**257**	543	912
Net Earnings–U.S. GAAP		**1,033**	871	2,380
Other Comprehensive Income (Loss), Net of Tax				
Foreign Currency Translation Adjustment		**(13)**	(238)	347
Compensation Plans		**(7)**	32	(9)
Comprehensive Income		**1,013**	665	2,718

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24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

CONDENSED CONSOLIDATED BALANCE SHEETS – U.S. GAAP

		2010		2009	
As at December 31,	Note 24	**As Reported**	**U.S. GAAP**	As Reported	U.S. GAAP
Assets					
Current Assets		**2,775**	**2,775**	2,453	2,453
Assets Held for Sale		**65**	**65**	-	-
Property, Plant and Equipment	*A, B, C ii)*				
(includes unproved properties and major development projects of $2,428 and $2,010 as of December 31, 2010 and 2009, respectively)		**29,020**	**28,997**	27,477	27,455
Accumulated Depreciation, Depletion and Amortization		**(13,490)**	**(14,045)**	(12,263)	(12,925)
Property, Plant and Equipment, net		**15,530**	**14,952**	15,214	14,530
(Full Cost Method for Oil and Gas Activities)					
Partnership Contribution Receivable		**2,145**	**2,145**	2,621	2,621
Risk Management		**43**	**43**	1	1
Other Assets	*C i)*	**391**	**390**	320	319
Goodwill		**1,146**	**1,146**	1,146	1,146
		22,095	**21,516**	21,755	21,070
Liabilities and Shareholders' Equity					
Current Liabilities	*C i), C ii), D*	**2,485**	**2,644**	1,984	2,098
Liabilities Related to Assets Held for Sale		**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
Asset Retirement Obligation		**1,213**	**1,213**	1,147	1,147
Other Liabilities	*C i), C ii)*	**346**	**348**	239	239
Deferred Income Taxes	*D*	**2,404**	**2,331**	2,467	2,368
		12,073	**12,161**	12,147	12,162
Shareholders' Equity	*E*	**10,022**	**9,355**	9,608	8,908
		22,095	**21,516**	21,755	21,070

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – U.S. GAAP

For the years ended December 31,	2010	2009	2008
Operating Activities			
Net earnings	**1,033**	871	2,380
Depreciation, depletion and amortization	**1,203**	1,288	1,376
Deferred income taxes	**116**	(396)	554
Unrealized (gain) loss on risk management	**(46)**	698	(899)
Unrealized foreign exchange (gain) loss	**(69)**	327	(317)
Accretion of asset retirement obligation	**75**	45	40
(Gain) loss on divestiture of assets	**9**	-	-
Other (income) loss, net	**35**	7	(20)
Net change in other assets and liabilities	**(55)**	(26)	(92)
Net change in non-cash working capital	**293**	225	202
Cash From Operating Activities	**2,594**	3,039	3,224
Cash (Used in) Investing Activities	**(1,796)**	(2,063)	(2,109)
Net Cash Provided before Financing Activities	**798**	976	1,115
Cash From (Used in) Financing Activities	**(631)**	(977)	(1,226)

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24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

Notes:

A) Full Cost Accounting

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in a cost centre do not exceed the sum, net of applicable income taxes, of the present value, discounted at 10 percent, of the estimated future net revenues calculated on the basis of estimated value of future production from proved reserves using oil and gas prices at the balance sheet date, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs. For 2010 and 2009, depletion charges under U.S. GAAP were also calculated by reference to proved reserves estimated using an average price for the prior 12-month period. For 2008, depletion charges under U.S. GAAP were calculated by reference to proved reserves estimated using oil and gas prices at the balance sheet date.

Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing and future development and production costs to determine whether impairment exists. The impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are also calculated by reference to proved reserves estimated using estimated future prices and costs.

At December 31, 2008, Cenovus's capitalized costs of oil and gas properties in Canada exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $73 million charged to DD&A. Additional depletion was also recorded in certain prior years, as a result of ceiling test differences between Canadian GAAP and U.S. GAAP. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

The U.S. GAAP adjustment for the difference in depletion calculations resulted in a decrease to DD&A of $107 million (2009–$237 million; 2008–$98 million).

B) Property, Plant and Equipment Allocation

For periods prior to the Arrangement, net property, plant and equipment related to Canadian upstream oil and gas activities have been allocated for U.S. GAAP carve-out purposes using the same methodology as the carve-out allocation for Canadian GAAP purposes.

The balances related to Canadian upstream operations have been allocated between Cenovus and Encana in accordance with the CICA Handbook Accounting Guideline AcG-16, based on the ratio of future net revenue, discounted at 10 percent, of the properties carved out to the discounted future net revenue of all proved properties in Canada using the reserve reports dated December 31, 2008. Future net revenue is the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves, the value of which has been determined by independent qualified reserve evaluators.

C) Compensation Plans

i) Pensions and Other Post-Employment Benefits

Under U.S. GAAP, ASC 715-30, *"Compensation – Retirement Benefits*", requires Cenovus to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through Other Comprehensive Income. Canadian GAAP does not require the recognition of the funded status of these plans on its balance sheet.

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24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

ii) Liability-Based Stock Compensation Plans

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, Cenovus adopted ASC 718, *"Compensation – Stock Compensation*" for the year ended December 31, 2006 using the modified-prospective approach. Under ASC 718, liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights and performance share appreciation rights, are required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in crude oil and natural gas development activities, certain amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. The current period adjustments have the following impact:

- Net property, plant and equipment decreased by $1 million (2009–$25 million decrease)
- Current liabilities decreased by $14 million (2009–$41 million decrease)
- Other liabilities decreased by $7 million (2009–$1 million increase)
- Operating expenses decreased by $9 million (2009–$4 million decrease)
- Administrative expenses decreased by $11 million (2009–$9 million decrease)
- No adjustment was made to depreciation, depletion and amortization expenses (2009–$2 million decrease)

D) Income Taxes

U.S. GAAP uses enacted tax rates and legislative changes to calculate current and deferred income taxes, whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2009, Cenovus incurred losses in one of its subsidiary companies which were recognized and included in calculating future income taxes for Canadian GAAP purposes on the basis that the tax legislative changes were substantially enacted. For U.S. GAAP, these losses were not recognized as the tax legislative changes were not enacted by December 31, 2009 nor December 31, 2010. There was no additional impact to income tax expense in 2010 (2009–$131 million, 2008–nil). In 2010 some of these losses were claimed to reduce the current taxes payable under Canadian GAAP. For U.S. GAAP the losses were not available and the current tax payable increased by $59 million offset by a decrease to the d eferred income tax payable with no impact on total tax expense.

The remaining differences resulted from the deferred income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other

reconciling items noted.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years ended December 31,	2010	2009	2008
Earnings Before Income Tax–U.S. GAAP	**1,290**	1,414	3,292
Canadian Statutory Rate	**28.2%**	29.2%	29.7%
Expected Income Tax	**364**	413	977
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(36)**	(7)	(88)
Non-deductible stock-based compensation	**32**	-	-
Multi-jurisdictional financing	**(93)**	(134)	(135)
Foreign exchange gains not included in net earnings	**28**	58	71
Non-taxable capital (gains) losses	**(9)**	30	(53)
Recognition of capital losses	**(107)**	-	-
Unrecognized non-capital losses	**-**	131	-
Other	**78**	52	140
Income Tax–U.S. GAAP	**257**	543	912
Effective Tax Rate	**19.9%**	38.4%	27.7%

The net deferred income tax liability consists of:

As at December 31,	2010	2009
Deferred Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,390**	2,407
Timing of partnership items	**125**	9
Net foreign exchange gains	**127**	-
Risk management	**55**	17
Other	**55**	79
Deferred Tax Assets		
Unused tax losses	**(209)**	(111)
Risk management	**(45)**	(33)
Other	**(167)**	-
Net Deferred Income Tax Liability	**2,331**	2,368

E) Other Comprehensive Income

ASC 715-30 requires a change in the funded status of defined benefit and post-employment plans to be recognized on the balance sheet and changes in the funded status through other comprehensive income. In 2010, a loss of $7 million, net of tax was recognized in other comprehensive income (2009–gain of $32 million) as noted in D i). On adoption of ASC 715-30, as required, the transitional amount of $24 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2010

24. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

F) Joint Venture with ConocoPhillips

Under Canadian GAAP, the Refining operations that are jointly controlled are proportionately consolidated. U.S. GAAP requires the Refining operations be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments does not require reconciliation from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity, which is the case for the Refining operations. Equity accounting for the Refining operations would have no impact on Cenovus's net earnings or retained earnings. As required, the following disclosures are provided for the Refining operations of the joint venture.

Consolidated Statements of Earnings		
For the years ended December 31,	2010	2009
Operating Cash Flow (See Note 1)	**67**	358
Depreciation, depletion and amortization	**(229)**	(220)
Other	**(12)**	(12)
Net Earnings (Loss)	**(174)**	126

Consolidated Balance Sheets		
As at December 31,	2010	2009
Current Assets	**951**	808

Long-term Assets	**5,275**	5,104
Current Liabilities	**559**	511
Long-term Liabilities	**327**	410

Consolidated Statements of Cash Flows		
For the years ended December 31,	**2010**	2009
Cash From (Used in) Operating Activities	**117**	(62)
Cash From (Used in) Investing Activities	**(657)**	(1,034)

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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, 2010, 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, 2010, 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, 2010, 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, 2010, 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 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 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, 2010, 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, 2010, 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, 2010, 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 registration statement to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 25, 2011

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 of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 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 Pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934, as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

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 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 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 function):

   (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 25, 2011

/s/ Brian C. Ferguson
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.2

Certification Pursuant to Rule 13a-14(a) or 15d-14(a)
of the Securities Exchange Act of 1934, as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

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 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 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 function):

   (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 25, 2011

/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, 2010, 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 25, 2011

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, 2010, 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 25, 2011

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, 2010; 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 18, 2011, relating to Cenovus Energy Inc.'s Consolidated Financial Statements as of December 31, 2010 and December 31, 2009, and for each of the years in the three year period ended December 31, 2010 and the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as of December 31, 2010.

/s/ PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
February 25, 2011

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, 2010, estimated using forecast prices and costs, and (ii) the contingent resources and economic resources of Cenovus Energy Inc. as at December 31, 2010, 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, 2010 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 Exchan ge 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 25, 2011

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, 2010, 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, 2010 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.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Dana B. Laustsen
Dana B. Laustsen, P. Eng.
Executive Vice-President

Calgary, Alberta
February 25, 2011