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.

WHERE TO FIND

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 Saskatchewan. 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 minimize 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 milestone 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.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

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.

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.

<u>Reserves and Resources</u>

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.

<u>Foster Creek</u>

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.

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 approximately 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. 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.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

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.

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.

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.

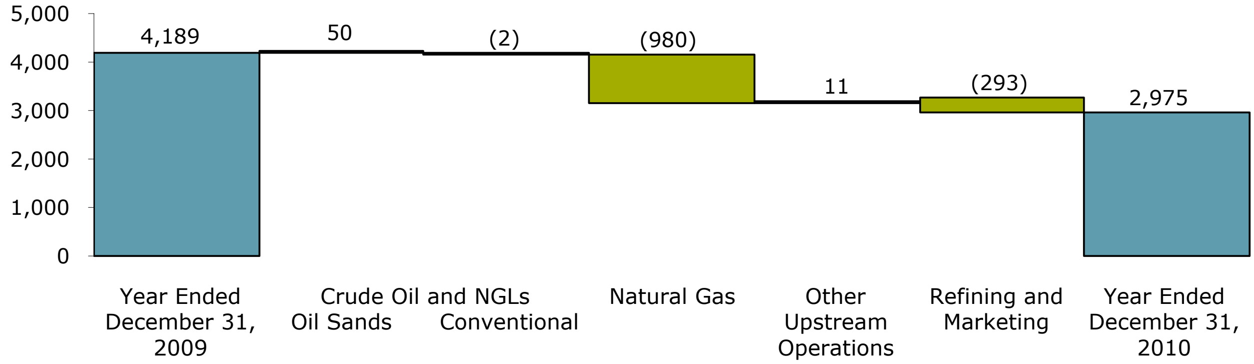
Our Refining and Marketing net revenues for 2010 increased primarily because of higher refined product prices and higher prices and volumes related to operational third party sales undertaken by the marketing group, partially offset by reduced refined products volumes from planned turnarounds, a power 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. 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.

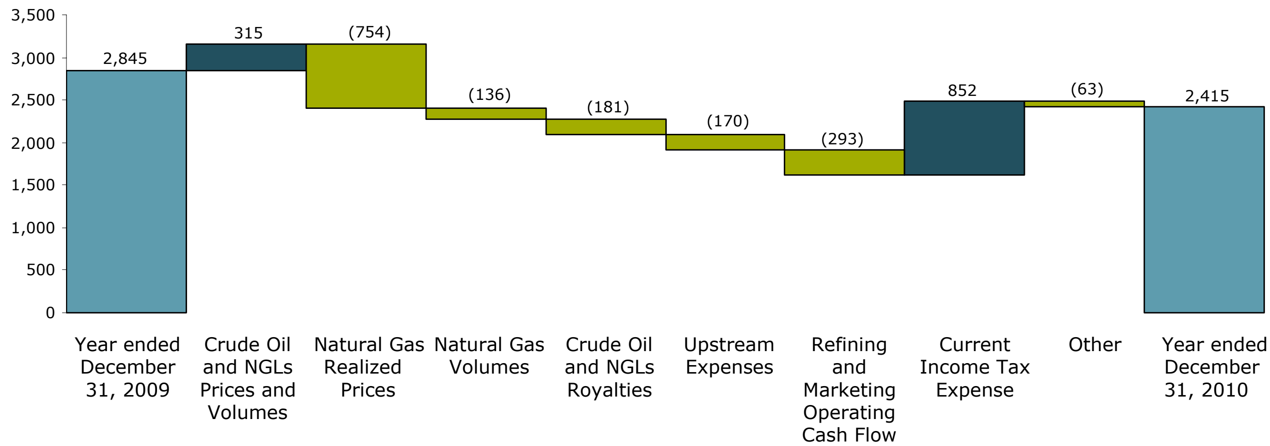
Operating cash flow for Refining and Marketing decreased $293 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds, a power outage and refinery optimization activities related to weaker diesel and gasoline prices primarily in the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



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.

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.

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. 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.

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	**Natural Gas**	Liquids	Natural Gas	Liquids	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)	($/bbl)	($/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.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

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

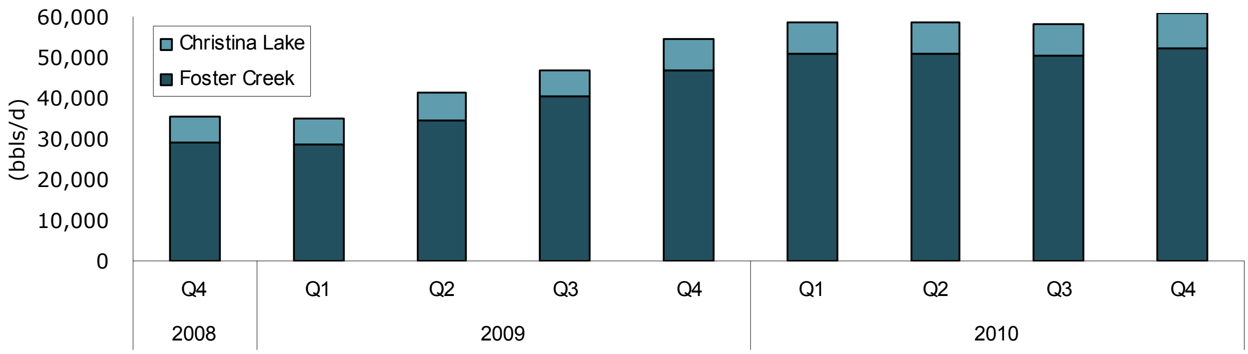
Financial Results

(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

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). 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.

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.

Cenovus Energy Inc. Management’s Discussion and Analysis (prepared in Canadian Dollars)

CRUDE OIL and NGLs

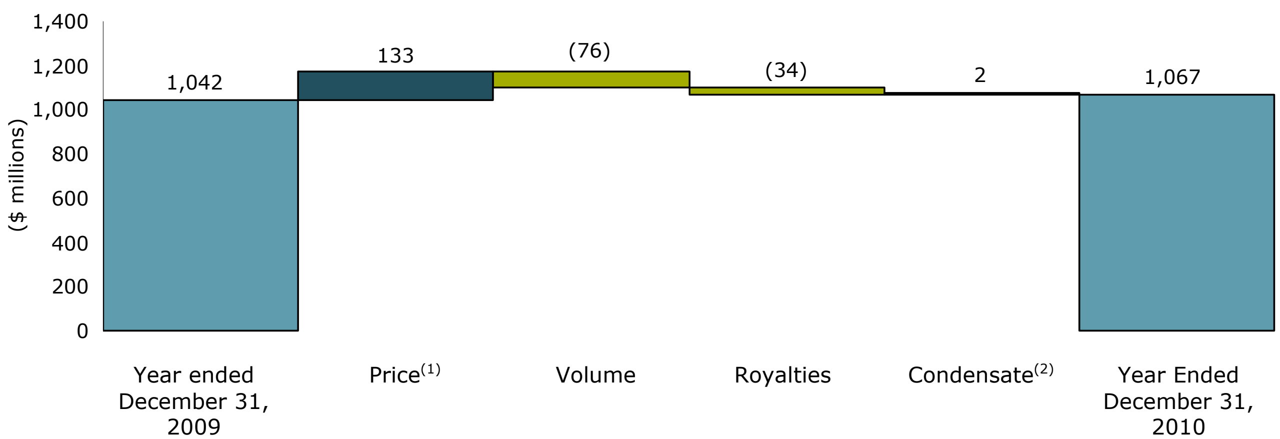
Financial Results

(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.

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.

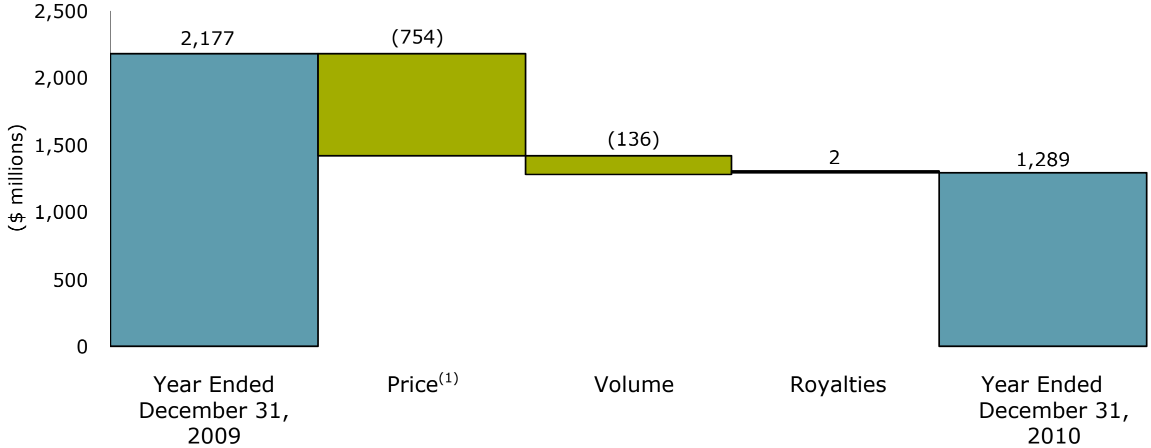
Our Conventional crude oil and NGLs operations generated $393 million of operating cash flow in excess of capital investment, a decrease of $137 million from 2009 mainly due to increased capital investment in 2010.

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

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

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 originally 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.

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. 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.

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
- 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.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

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.

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.

Cenovus Energy Inc. Management’s Discussion and Analysis (prepared in Canadian Dollars)

RESOURCES AT DECEMBER 31

Before Royalties	Bitumen (billions of barrels) 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.

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. 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. 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.

Cenovus Energy Inc. Management's Discussion and Analysis (prepared in Canadian Dollars)

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.

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.

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 which 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.

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, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

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

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. 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.

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 considering 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.

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. 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. 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.

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

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 formation of Cenovus. The allocation process did not affect the net book value of our Upstream PP&E as no IFRS impairments were recognized.

<u>DD&A</u>
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.

<u>Gains and losses on divestitures</u>
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. 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.

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.

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 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 relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in 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 regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

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

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.

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.