Cenovus Energy Inc.

Management's Discussion and Analysis
For the Period Ended September 30, 2010
(Canadian Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated October 27, 2010, should be read with the unaudited Interim Consolidated Financial Statements for the period ended September 30, 2010 ("Interim Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements for the year ended December 31, 2009 (the "Consolidated Financial Statements") and Encana Corporation's ("Encana") Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. (the "Information Circular") dated October 20, 2009. This MD&A contains forward looking information based on our current expectations and projections. For information on the material factors and assumptions underlying our forward looking information, see the Advisory at the end of this MD&A.

Management is responsible for preparing the MD&A. The Audit Committee of the Board of Directors of Cenovus (the "Board") approves the MD&A for interim periods, while the annual MD&A is approved by the Board.

This MD&A and the Interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production volumes are presented on a before royalties basis.

Definitions of certain terms used in this document are contained in the Advisory section at the end of this MD&A.

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 $22 billion on September 30, 2010. In the third quarter of 2010, we had production of 251,067 boe/d. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. In southern Saskatchewan, we inject carbon dioxide ("CO_2") to enhance oil recovery at our Weyburn operation. We also have established crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have a 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 our oil sands projects at Foster Creek and Christina Lake and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach and our established 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: Narrows Lake, Grand Rapids and Telephone Lake.

Through our interest in the FCCL Partnership, we hold an approximate 50 percent interest in the Narrows Lake property, which is located within the greater Christina Lake Region. In the first quarter of 2010, we initiated the regulatory approval process for Narrows Lake by filing proposed terms of reference for an environmental impact assessment ("EIA") and began public consultation for the project. In the second quarter of 2010, final terms of reference were issued by Alberta Environment and a joint application and EIA was filed. The project is expected to begin producing in 2016 and include gross production capacity of 130,000 bbls/d in three phases, with the first phase expected to add production capacity of approximately 40,000 bbls/d.

During the second quarter of 2010, we received approval from the Alberta Energy Resources Conservation Board ("ERCB") to begin a pilot project at our 100 percent owned Grand Rapids project, which is located within the Greater Pelican Region. The drilling of a SAGD well pair is complete and construction of associated facilities is underway. We are currently waiting for approval from Alberta Environment to start this pilot project. If this pilot is successful, we then expect to file a regulatory application for a commercial operation with production capacity of 180,000 bbls/d by the end of 2011.

We have a 100 percent working interest in the Telephone Lake property, in the Greater Borealis Region. A joint application and EIA has been submitted to the ERCB and Alberta Environment for the development of the property, including the construction of a facility with 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. In April and June, we issued news releases that highlight detailed information related to our bitumen economic contingent resources and bitumen initially-in-place, enabling 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. Our 10 year business plan is to grow our net oil sands production to 300,000 bbls/d by the end of 2019. Growth is expected to be 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 a natural economic hedge for the natural gas required as a fuel source at both our upstream and downstream operations. Our refineries, which are operated by ConocoPhillips, an unrelated United States ("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 Wood River Coker and Refinery Expansion ("CORE") project. We also employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we will continue to pay meaningful dividends, currently $0.20 per share per quarter, to deliver strong total shareholder return over the long term.

OUR BUSINESS STRUCTURE

Our operations are organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other oil sands interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major oil sands projects: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.
- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major oil properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division 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.

For financial statement reporting purposes, our operating and reportable segments are:

- **Upstream Canada,** which includes Cenovus's development and production of crude oil, natural gas and NGLs, and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips and operated by Cenovus, as well as several other emerging projects.
- **Downstream Refining,** which is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with ConocoPhillips and operated by ConocoPhillips.
- **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, realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

OVERVIEW OF THE THIRD QUARTER 2010

The specific operating and financial highlights of the third quarter of 2010 compared to the third quarter of 2009 are:

- Production from our Foster Creek and Christina Lake oil sands projects increased by 25 percent;
- Net Revenues increased by 4 percent;
- Upstream Operating Cash Flow decreased by $347 million because of lower natural gas volumes and realized prices as well as lower realized crude oil prices, partially offset by higher crude oil volumes. The impact of realized hedging on upstream Operating Cash Flow was a gain of $86 million compared to a gain of $337 million in 2009;
- Operating Cash Flow from Downstream Refining operations decreased by $127 million due to increased per barrel crude oil purchased product costs and reduced crude utilization as a result of a planned turnaround, a power outage and unplanned maintenance;
- Cash Flow decreased by $415 million, primarily due to lower realized natural gas prices and lower Downstream Refining Operating Cash Flows;
- Operating Earnings decreased by $268 million, mostly due to lower Operating Cash Flows; and
- Declared and paid dividends of $150 million ($0.20 per share) in the third quarter of 2010.

The 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 $61 million during the quarter (year to date - $143 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 reflect natural gas hedges put in place for 2010 at approximately $6.00 per Mcf as compared to hedges for 2009 put in place at approximately $9.00 per Mcf back 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.

In the third quarter of 2010 we received regulatory approval from the ERCB for the next three phases of expansion at Foster Creek, which are phases F, G and H. When all three phases are completed, the expansion is expected to increase Foster Creek's production capacity from the current 120,000 bbls/d to 210,000 bbls/d. The next step for this expansion is to receive final partner approval for the entire expansion. Engineering and preliminary ground work on phase F is already underway. First production for this phase is expected in 2014 based on planned project acceleration of up to 12 months. Production from the other two phases is expected in 2016-2017.

The construction of the Christina Lake expansions is progressing with phases C and D each expected to add an additional 40,000 bbls/d of production capacity. Production from phase C is expected to begin in the second half of 2011 and production from phase D is expected to begin in 2013. These expansion phases are expected to bring Christina Lake's production capacity to 98,000 bbls/d in 2013.

At the end of the third quarter, the CORE project was approximately 87 percent complete. Commissioning of several of the process units has been completed with an expected coker startup in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach US$3.7 billion (50 percent net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (50 percent net to Cenovus), or about 10 percent higher than originally forecast.

In the third quarter we continued with our divestiture program and sold certain non-core assets in southeastern Alberta and southwestern Saskatchewan for net proceeds of $159 million.

Unusual weather patterns across our operating areas throughout the year, including a very wet summer, restricted access and as a result our upstream capital investment program is 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 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 Average Benchmark Prices (1)

	Nine Months Ended September 30		**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2010	2009	**2010**	2010	2010	2009	2009	2009	2009	2008	2008
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate ("WTI")	**77.69**	57.32	**76.21**	78.05	78.88	76.13	68.24	59.79	43.31	59.08	118.22
Western Canada Select ("WCS")	**64.76**	48.47	**60.56**	63.96	69.84	64.01	58.06	52.37	34.38	39.95	100.22
Differential – WTI/WCS	**12.93**	8.85	**15.65**	14.09	9.04	12.12	10.18	7.42	8.93	19.13	18.00
WCS as percent of WTI	**83%**	85%	**79%**	82%	89%	84%	85%	88%	79%	68%	85%
Condensate (C5 @ Edmonton)	**80.76**	56.91	**74.53**	82.87	84.98	74.42	65.76	58.07	46.26	57.02	121.17
Differential – WTI/Condensate (premium)/discount	**(3.07)**	0.41	**1.68**	(4.82)	(6.10)	1.71	2.48	1.72	(2.95)	2.06	(2.95)
Refining Margin 3-2-1 Crack Spreads (2) *(US$/bbl)*											
Chicago	**9.35**	9.72	**10.34**	11.60	6.11	5.00	8.48	10.95	9.75	6.31	17.29
Midwest Combined (Group 3)	**9.60**	8.95	**10.60**	11.38	6.82	5.52	8.06	9.16	9.62	6.00	14.38
Natural Gas Prices											
AECO *($/GJ)*	**4.09**	3.89	**3.52**	3.66	5.08	4.01	2.87	3.47	5.34	6.43	8.76
NYMEX *(US $/MMBtu)*	**4.59**	3.92	**4.38**	4.09	5.30	4.17	3.39	3.50	4.89	6.94	10.24
Basis Differential NYMEX/AECO *(US $/MMBtu)*	**0.43**	0.47	**0.78**	0.32	0.19	0.19	0.67	0.39	0.35	1.10	1.28
Foreign Exchange											
Average US/Canadian dollar exchange rate	**0.966**	0.855	**0.962**	0.973	0.961	0.947	0.911	0.857	0.803	0.825	0.961

(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 benchmark WTI began the third quarter at US$75.63 per bbl and rose through July to a peak spot price of US$82.52 per bbl in early August before retreating to a closing spot price of US$79.97 per bbl at the end of September on reaction to reports of a weakening economy and growing U.S. crude and product inventories. WTI averaged US$76.21 per bbl in the third quarter of 2010, slightly lower than the first two quarters of 2010 but approximately 12 percent higher than the same period in 2009. The average WTI price for the nine months ended September 30, 2010 was approximately 36 percent higher than in 2009, a result of increased global crude oil demand, mainly from developing countries, and the effects of substantial cuts in OPEC production.

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 discount to WTI in the first three quarters of 2010 averaged US$12.93 per bbl or approximately 17 percent of WTI. The widening of the WTI/WCS differential in the third quarter and year to date was mainly the result of pipeline transportation disruptions of crude oil from Alberta to mid-west U.S. refineries in the third quarter. The disruption resulted in an increase in WCS inventory which reduced the market price of WCS. At the same time, the price of WTI was relatively unchanged resulting in the differential widening to as much as US$31.00 per bbl. The end of September saw the differential narrowing to approximately US$15.00 per bbl on the resumption of regular pipeline operations.

Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The condensate/WTI differential shown above is the benchmark price of condensate relative to the price of WTI. The cost of condensate purchases impacts both our revenues and transportation and selling costs. The differentials for WTI/WCS and WTI/Condensate are independent of one another and tend not to move in tandem.

WTI is also an important benchmark as it is used as the basis for determining post payout royalties at our oil sands properties.

Benchmark crack spreads for the third quarter of 2010 were better than 2009 due 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 during the summer driving season in North America.

In the third quarter of 2010, NYMEX natural gas prices improved over the third quarter of 2009 primarily due to increased consumption for electric power generation as a result of a very warm summer in the U.S. Demand for natural gas in the industrial sector of the U.S. also increased in 2010. Natural gas volumes in storage in 2010 have decreased from the same period in 2009 but still remain above the 5-year average which reduces the market prices of natural gas.

During 2010, the Canadian dollar has strengthened relative to the U.S. dollar. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sale prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our Downstream Refining segment operates in U.S. dollars and therefore a strengthened Canadian dollar reduces this segment's results.

Our risk mitigation strategy has helped reduce our exposure to commodity price volatility. Realized hedging gains, after-tax, in the third quarter were $61 million (year to date - $143 million). Further information regarding our hedging program can be found in the notes to the Interim Consolidated Financial Statements. Also, further information regarding the sensitivity of our 2010 financial results to changes in various benchmark prices can be found in our 2010 Corporate Guidance document, which was updated as at October 28, 2010, and is available on our website, www.cenovus.com.

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)	**Nine Months Ended September 30**		**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2010	2009	**2010**	2010	2010	2009	2009	2009	2009	2008	2008
Net Revenues	**9,801**	8,512	**3,115**	3,195	3,491	3,005	3,001	2,818	2,693	3,946	5,753
Operating Cash Flow (1)	**2,163**	3,235	**660**	665	838	954	1,134	1,173	928	121	1,176
Cash Flow (1)	**1,767**	2,610	**509**	537	721	235	924	945	741	(209)	1,161
- per share – diluted (2)	**2.35**	3.48	**0.68**	0.71	0.96	0.31	1.23	1.26	0.99	(0.28)	1.54
Operating Earnings (1)	**654**	1,353	**159**	142	353	169	427	512	414	(159)	623
- per share – diluted (2)	**0.87**	1.80	**0.21**	0.19	0.47	0.23	0.57	0.68	0.55	(0.21)	0.82
Net Earnings	**920**	776	**223**	172	525	42	101	160	515	490	1,341
- per share – basic (2)	**1.22**	1.03	**0.30**	0.23	0.70	0.06	0.13	0.21	0.69	0.65	1.79
- per share – diluted (2)	**1.22**	1.03	**0.30**	0.23	0.70	0.06	0.13	0.21	0.69	0.65	1.78
Capital Investment	**1,403**	1,655	**480**	430	493	507	515	488	652	760	487
Free Cash Flow (1)	**364**	955	**29**	107	228	(272)	409	457	89	(969)	674
Cash Dividends (3)	**450**	-	**150**	150	150	159	-	-	-	-	-

(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 plan of arrangement ("the Arrangement"), wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.

(3) We declared and paid a dividend of $0.20 per share in each of the first three quarters of 2010 and US$0.20 per share in the fourth quarter of 2009. The fourth quarter 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)		Three Months Ended	Nine Months Ended
Net Revenues for the Periods Ended September 30, 2009		$ 3,001	$ 8,512
Increase (decrease) due to:			
Upstream Canada	Prices	26	374
	Realized hedging	(250)	(793)
	Volume	(49)	12
	Royalties	(28)	(166)
	Other (1)	168	741
Downstream Refining		(182)	266
Corporate and Eliminations	Unrealized hedging	415	865
	Other	14	(10)
Net Revenues for the Periods Ended September 30, 2010		**$ 3,115**	**$ 9,801**

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

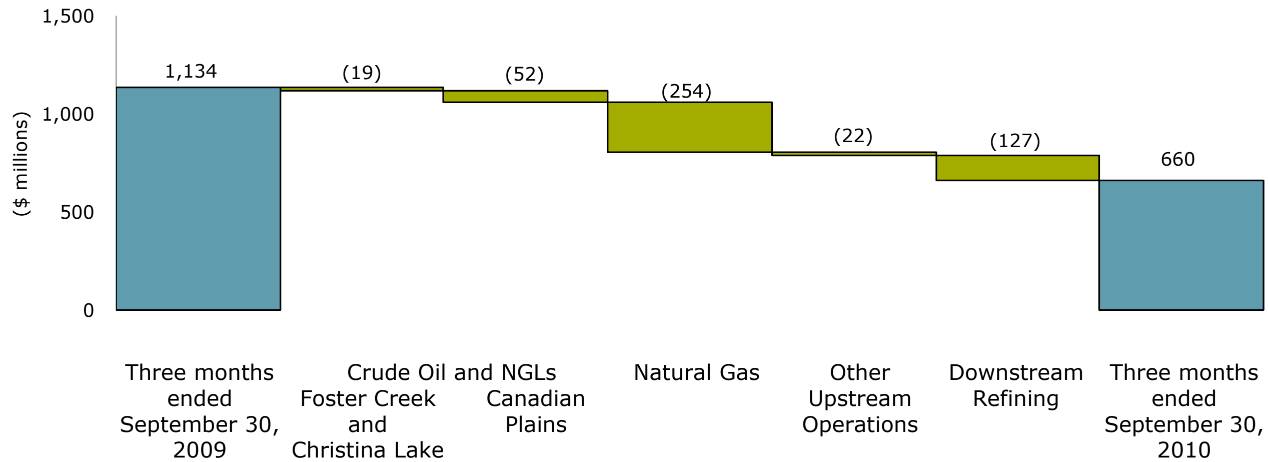
Our Upstream Canada Net Revenues increased in the third quarter of 2010 and the nine months ended September 30, 2010, primarily because of higher crude oil production volumes partially offset by lower volumes and realized prices for natural gas and higher royalties. Year to date Net Revenues also increased because of higher realized oil prices. Our Downstream Refining Net Revenues for the third quarter decreased because of reduced volumes resulting from a planned turnaround, a power outage and unplanned maintenance, while the year to date Net Revenues increased because of higher refined product prices. Also increasing Net Revenues in the third quarter and for the nine months ended were unrealized hedging gains. Further information and explanations regarding our Net Revenues can be found in the Divisional Results and Corporate and Eliminations sections of this MD&A.

OPERATING CASH FLOW

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Crude Oil and NGLs				
Foster Creek and Christina Lake	**$ 179**	$ 198	**$ 570**	$ 431
Canadian Plains	**262**	314	**805**	768
Natural Gas	**246**	500	**828**	1,649
Other Upstream Operations	**5**	27	**22**	41
	692	1,039	**2,225**	2,889
Downstream Refining	**(32)**	95	**(62)**	346
Operating Cash Flow	**$ 660**	$ 1,134	**$ 2,163**	$ 3,235

Operating Cash Flow is a non-GAAP measure defined as Net Revenues less production and mineral taxes, transportation and selling, 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 periods. Operating Cash Flow excludes unrealized hedging gains and losses which are included in the Corporate and Eliminations segment.

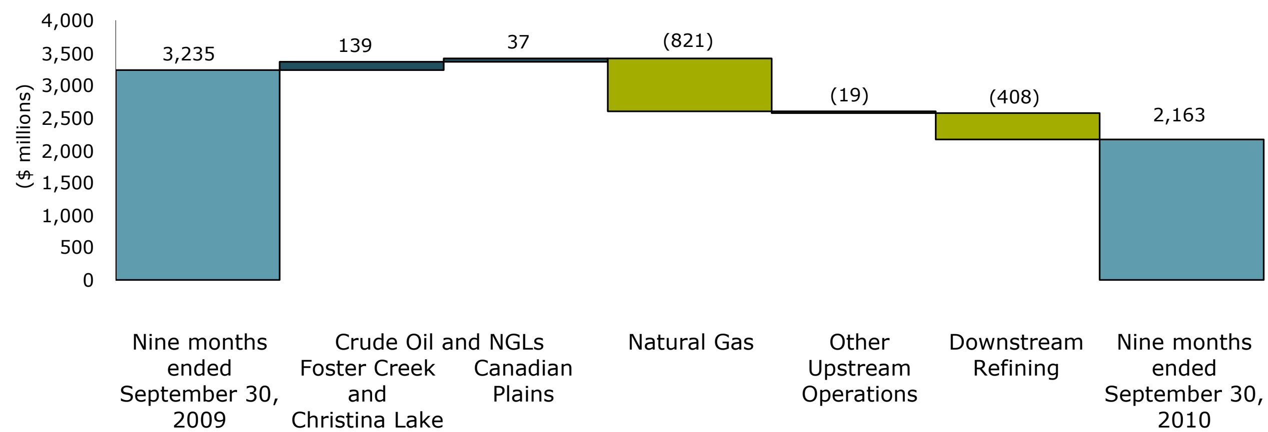
Three Months Ended September 30, 2010 compared to 2009



Operating Cash Flows decreased by $474 million in the third quarter of 2010 primarily because of a $254 million reduction related to natural gas as a result of lower realized prices along with lower natural gas volumes.

Operating Cash Flows from our Downstream Refining segment decreased $127 million mainly due to increased per barrel crude oil purchased product costs and reduced crude utilization as a result of a planned turnaround, a power outage and unplanned maintenance. Other factors decreasing our Operating Cash Flows were lower netbacks for crude oil resulting from increased production volumes that were offset by lower realized prices, higher oil royalties and higher operating expenses. Details of the components that explain this decrease can be found in the Divisional Results section of this MD&A.

Nine Months Ended September 30, 2010 compared to 2009



Operating Cash Flows decreased by $1,072 million for the nine months ended September 30, 2010 primarily because of a $821 million reduction related to natural gas as a result of lower realized prices along with lower natural gas volumes.

Operating Cash Flows for Downstream Refining decreased $408 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds, a power outage, unplanned maintenance and refinery optimization. Other factors affecting our Operating Cash Flows were improvements in crude oil as increased realized prices and production were partially offset by higher royalties. Details of the components that explain this decrease can be found in the Divisional Results 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.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Cash From Operating Activities	**$ 645**	$ 1,414	**$ 1,936**	$ 2,889
(Add back) deduct:				
Net change in other assets and liabilities	**(13)**	(3)	**(41)**	(12)
Net change in non-cash working capital	**149**	493	**210**	291
Cash Flow	**$ 509**	$ 924	**$ 1,767**	$ 2,610

Three Months Ended September 30, 2010 compared to 2009

In the third quarter of 2010 Cash Flow decreased $415 million primarily due to:

- A 37 percent decrease in the realized average natural gas price, including the impact of hedges, to $4.77 per Mcf compared to $7.55 per Mcf;
- A decrease in Operating Cash Flow from Downstream Refining of $127 million;
- An increase in royalties of $28 million primarily as a result of Foster Creek achieving royalty payout and higher WTI prices used for determining royalties;
- A realized foreign exchange loss of $14 million in 2010 compared to a gain of $14 million in 2009;
- A three percent decrease in our realized average liquids price, including the impact of hedging, to $61.81 per bbl compared to $63.84 per bbl;
- Natural gas production declining 11 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production; and
- An increase in net interest expense of $15 million.

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

- A $107 million decrease in current income tax expense as a result of lower realized hedging gains and utilizing claims from tax pools that we received as a result of the Arrangement; and
- A one percent increase in our crude oil and NGLs production volumes.

Nine Months Ended September 30, 2010 compared to 2009

Cash Flow for the nine months ended September 30, 2010 decreased $843 million mainly due to:

- A 37 percent decrease in the realized average natural gas price, including the impact of hedges, to $5.19 per Mcf compared to $8.19 per Mcf;
- A decrease in Operating Cash Flow from Downstream Refining of $408 million;
- An increase in royalties of $166 million, primarily as a result of Foster Creek achieving royalty payout and higher crude oil prices;
- Natural gas production declining 11 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production;
- An increase in general and administrative and net interest expenses of $62 million; and
- A realized foreign exchange loss of $16 million compared to a gain of $30 million.

The Cash Flow decreases above were partially offset by:

- Current income tax expense decreasing $326 million primarily due to lower realized hedging gains and utilizing claims from tax pools that we received as a result of the Arrangement;
- A 13 percent increase in the realized average liquids selling price, including the impact of hedges, to $62.97 per bbl compared to $55.88 per bbl; and
- An eight percent increase in our crude oil and NGLs production volumes.

OPERATING EARNINGS

(millions of dollars)	Three Months Ended September 30 2010	2009	Nine Months Ended September 30 2010	2009
Net Earnings	**$ 223**	$ 101	**$ 920**	$ 776
(Add back) deduct:				
Unrealized mark-to-market accounting gain (loss), after-tax [(1)]	**45**	(252)	**231**	(402)
Non-operating foreign exchange gain (loss), after-tax [(2)]	**19**	(74)	**35**	(175)
Operating Earnings	**$ 159**	$ 427	**$ 654**	$ 1,353

(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 debt issued from Canada and the partnership contribution receivable, after-tax realized 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 gains or losses on discontinuance, 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 declines in our Operating Earnings for the three and nine months ended September 30, 2010 compared to 2009 were consistent with the decreases to our Operating Cash Flow and Cash Flow, details of which can be found above.

NET EARNINGS VARIANCE

(millions of dollars)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2009	$ 101	$ 776
Increase (decrease) due to:		
Net revenues	114	1,289
Expenses:		
Transportation and selling	(19)	(251)
Purchased product	(131)	(1,223)
Other expenses [(1)]	98	138
Depreciation, depletion and amortization	76	189
Income taxes	(16)	2
Net Earnings for the Periods Ended September 30, 2010	**$ 223**	**$ 920**

(1) Includes net expenses for Production and mineral taxes, Operating, General and Administrative, Interest, net, Accretion of asset retirement obligation, Foreign exchange (gain) loss, (Gain) loss on disposal of assets and Other (income) loss, net.

Net Earnings in the third quarter of 2010 increased by $122 million. The items identified above that reduced our Cash Flow in the third quarter also reduced our Net Earnings. There were other significant factors that impacted our third quarter 2010 Net Earnings including:

- Unrealized mark-to-market gain, after-tax, of $45 million, compared to a $252 million loss, after-tax, in the third quarter of 2009;
- Unrealized foreign exchange gain of $38 million in the third quarter of 2010 compared to a loss of $134 million;
- A decrease of $76 million in depreciation, depletion and amortization ("DD&A"); and
- Future income tax expense, excluding the impact of the unrealized financial hedging gains, in the third quarter of 2010 of $16 million, compared to $9 million in 2009.

For the nine months ended September 30, 2010 Net Earnings increased by $144 million when compared to the same period in 2009. The items previously discussed that reduced our Cash Flow for the nine months ended September 30, 2010 also reduced our Net Earnings. There were other significant factors that impacted our 2010 Net Earnings including:

- Unrealized mark-to market gain, after-tax of $231 million compared to a loss, after-tax of $402 million in 2009;
- DD&A expense decrease of $189 million;
- Unrealized foreign exchange gain of $39 million for year to date 2010 compared to a loss of $241 million in 2009; and
- Future income tax expense, excluding the impact of the unrealized financial hedging gains, of $39 million, compared to a future income tax recovery of $35 million in 2009.

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 the mark-to-market gain or loss 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. The following information has been provided in order to provide information that is more comparable between periods:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Unrealized Mark-to-Market Gains (Losses), after-tax [1]	**$ 45**	$ (252)	**$ 231**	$ (402)
Realized Hedging Gains (Losses), after-tax [2]	**61**	238	**143**	686
Hedging Impacts in Net Earnings	**$ 106**	$ (14)	**$ 374**	$ 284

(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 Divisional financial results and included in Operating Cash Flow and Cash Flow.

NET CAPITAL INVESTMENT

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Integrated Oil – Upstream	**$ 157**	$ 119	**$ 455**	$ 396
Canadian Plains	**166**	104	**407**	438
Downstream Refining	**146**	291	**516**	808
Other	**11**	1	**25**	13
Capital Investment	**480**	515	**1,403**	1,655
Acquisitions	**4**	1	**51**	2
Divestitures	**(168)**	2	**(312)**	(1)
Net Capital Investment	**$ 316**	$ 518	**$1,142**	$ 1,656

Capital investment for both the three and nine months ended September 30, 2010 was primarily focused on the continued development of our Integrated Oil – Upstream oil sands projects and Canadian Plains oil properties, including the drilling of stratigraphic wells to support the next phases of our expansion activities. Downstream Refining capital investment was primarily related to the expansion of our heavy oil refining capacity. Capital investment was funded by Cash Flow. Further information regarding our capital investment can be found in the Divisional Results section of this MD&A.

Acquisitions and Divestitures

We continued with our planned program to divest of non-core assets in the third quarter of 2010 and sold certain non-core natural gas producing properties for net proceeds of $159 million.

Acquisitions during the nine months ended September 30, 2010 were primarily related to the purchase of undeveloped land at Narrows Lake. Other divestitures during the nine months ended September 30, 2010 included the divestiture of certain non-core producing properties as well as the sale of certain lands at the Narrows Lake property to the FCCL Partnership.

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, excluding acquisitions and divestitures. Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

	Three months ended September 30		**Nine months ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Cash Flow	**$ 509**	$ 924	**$ 1,767**	$ 2,610
Capital Investment	**480**	515	**1,403**	1,655
Free Cash Flow	**$ 29**	$ 409	**$ 364**	$ 955

In the third quarter of 2010, Free Cash Flow was $380 million lower than the same period in 2009, while for the nine months ended September 30, 2010, Free Cash Flow decreased by $591 million. Explanations for the decrease in Cash Flow and Capital Investment are discussed under the Cash Flow, Net Capital Investment and Divisional Results sections of this MD&A.

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

(bbls/d)	**Q3 2010**	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008
Crude Oil									
Foster Creek	**50,269**	51,010	51,126	47,017	40,367	34,729	28,554	29,241	27,289
Christina Lake	**7,838**	7,716	7,420	7,319	6,305	6,530	6,635	6,170	4,620
Pelican Lake	**23,259**	23,319	23,565	23,804	25,671	23,989	26,029	24,975	27,826
Weyburn	**17,621**	18,043	17,722	18,536	18,354	18,368	18,028	17,408	17,634
Southern Alberta	**23,216**	22,458	23,790	23,729	23,895	24,089	25,404	25,509	25,654
Canadian Plains – Other	**4,692**	4,854	5,770	5,506	5,573	5,806	5,862	6,090	6,166
Integrated Oil – Senlac	**-**	-	-	2,221	5,080	2,574	2,334	2,623	3,135
NGLs	**1,172**	1,166	1,156	1,183	1,242	1,184	1,213	1,158	1,167
	128,067	128,566	130,549	129,315	126,487	117,269	114,059	113,174	113,491

When compared to the same periods in 2009, overall crude oil and NGLs production increased one percent in the third quarter and eight percent year to date to 129,052 bbls/d. Quarterly production volumes increased 25 percent at Foster Creek (year to date – 47 percent) and 24 percent at Christina Lake (year to date – 18 percent). These increases were partially offset by natural declines at our other properties, as well as the sale of certain non-core properties in 2010 and our Senlac property in the fourth quarter of 2009. Further detail on the changes in our production can be found in the Divisional Results section of this MD&A.

Natural Gas Production Volumes

(MMcf/d)	**Q3 2010**	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008
Southern Alberta	**666**	676	699	719	741	761	777	803	815
Canadian Plains – Other	**31**	32	34	34	37	41	39	40	44
Integrated Oil – Other	**41**	43	42	44	52	54	50	62	88
	738	751	775	797	830	856	866	905	947

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. As a result our overall natural gas production has decreased 11 percent in the third quarter and 11 percent year to date to 754 MMcf/d. Quarterly production volumes declined 10 percent in Southern Alberta (year to date – 10 percent) compared to the same quarter of 2009. Weather related delays experienced throughout 2010 also negatively impacted our natural gas production. Further detail on the changes in our production can be found in the Divisional Results section of this MD&A.

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

Operating Netbacks - Quarter

	Three Months Ended September 30			
	2010		2009	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$ 60.80**	**$ 3.68**	$ 63.85	$ 3.14
Royalties	**8.96**	**0.08**	6.60	0.02
Production and mineral taxes	**0.59**	**0.03**	0.63	0.04
Transportation and selling	**1.97**	**0.15**	1.67	0.16
Operating expenses	**11.72**	**0.94**	9.61	0.84
Netback excluding Realized Financial Hedging	**37.56**	**2.48**	45.34	2.08
Realized Financial Hedging Gain (Loss)	**1.01**	**1.09**	(0.01)	4.41
Netback including Realized Financial Hedging	**$ 38.57**	**$ 3.57**	$ 45.33	$ 6.49

Our 2010 third quarter average netback for liquids, excluding realized financial hedging, decreased by $7.78 per bbl. The decrease was the result of a combination of lower prices and higher royalties as well as higher operating expenses. Our average netback for natural gas, excluding realized financial hedging, was higher as a result of higher natural gas prices, partially offset by higher operating expenses.

Operating Netbacks – Year to Date

	Nine Months Ended September 30			
	2010		2009	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$ 63.03**	**$ 4.25**	$ 54.36	$ 4.14
Royalties	**9.23**	**0.10**	5.01	0.06
Production and mineral taxes	**0.63**	**0.02**	0.72	0.06
Transportation and selling	**1.90**	**0.17**	1.78	0.16
Operating expenses	**11.74**	**0.94**	10.58	0.87
Netback excluding Realized Financial Hedging	**39.53**	**3.02**	36.27	2.99
Realized Financial Hedging Gain (Loss)	**(0.06)**	**0.94**	1.52	4.05
Netback including Realized Financial Hedging	**$ 39.47**	**$ 3.96**	$ 37.79	$ 7.04

In the first nine months of 2010, our average netback for liquids, excluding realized financial hedging, increased by $3.26 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, was consistent with 2009.

Further discussions of operating results are contained in the Divisional Results section of this MD&A.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our pricing 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 Interim Consolidated Financial Statements.

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

DIVISIONAL RESULTS

Our Upstream Canada segment includes the upstream activities of the Integrated Oil Division and the Canadian Plains Division. Our Downstream Refining segment includes the Downstream Refining business of the Integrated Oil Division.

INTEGRATED OIL DIVISION

We are a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes the Foster Creek, Christina Lake and Narrows Lake oil sands projects in northeast Alberta, while the downstream entity includes the Wood River and Borger refineries located in Illinois and Texas, U.S.A., respectively.

Highlights of the third quarter include receiving regulatory approval for the next three phases of expansion at Foster Creek, significant increases in production at both Foster Creek and Christina Lake as well as continued progress on the development of our other oil sands projects. In addition, the CORE project progressed to approximately 87 percent complete with coker construction expected to be complete in the third quarter of 2011 followed by coker start up early in the fourth quarter.

FOSTER CREEK AND CHRISTINA LAKE

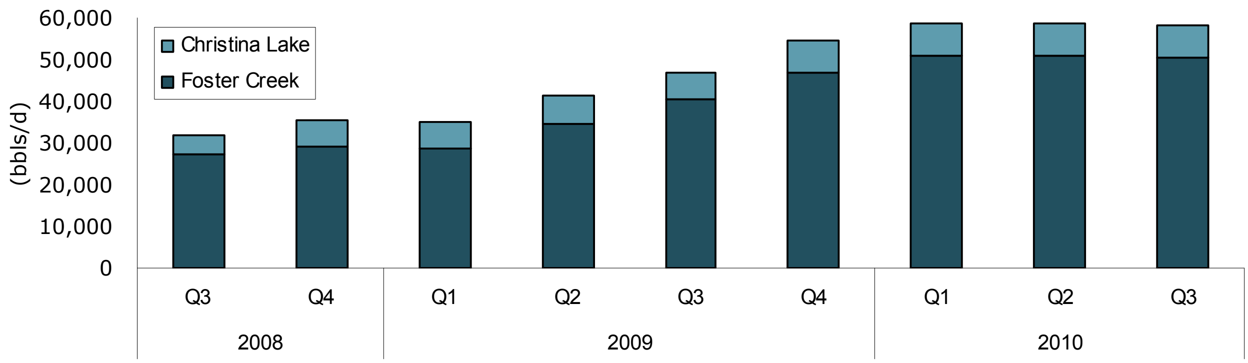
Financial Results

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 436**	$ 386	**$ 1,466**	$ 871
Deduct (add)				
Realized financial hedging (gain) loss	**1**	-	**9**	(45)
Royalties	**42**	8	**115**	11
Net revenues	**393**	378	**1,342**	905
Expenses				
Transportation and selling	**158**	131	**595**	330
Operating	**56**	49	**177**	144
Operating Cash Flow	**$ 179**	$ 198	**$ 570**	$ 431

Production Volumes

	Three Months Ended September 30			**Nine Months Ended September 30**		
Crude oil *(bbls/d)*	**2010**	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Foster Creek	**50,269**	**25%**	40,367	**50,798**	**47%**	34,593
Christina Lake	**7,838**	**24%**	6,305	**7,660**	**18%**	6,489
	58,107	**25%**	46,672	**58,458**	**42%**	41,082

Production Volumes by Quarter



Net Revenues Variance

<u>Three Months Ended September 30, 2010 compared to 2009</u>

(millions of Canadian dollars)	Three Months Ended September 30, 2009 Net Revenues	Net Revenue Variances in: Price[1]	Volume	Royalties	Other[2]	**Three Months Ended September 30, 2010 Net Revenues**
Foster Creek and Christina Lake	$ 378	(23)	47	(34)	25	**$ 393**

(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 selling expense.

In the third quarter the average crude oil sales price, excluding realized financial hedges, of $58.20 per bbl was lower than the 2009 price of $62.57 per bbl. Although the market price of WCS in 2010 was higher than 2009, it was more than offset by higher condensate prices in 2010 compared to 2009. In the third quarter of 2010, financial hedging activities resulted in a realized loss of $1 million compared to a loss of under $1 million in 2009.

Production at Foster Creek increased 25 percent in the third quarter of 2010 as a result of increased production from the phase D and E expansions combined with well optimizations and increased production from wedge wells. During the third quarter of 2010, Foster Creek production was reduced as a result of two power outages and a water-handling system disruption. At the end of the third quarter, certain Foster Creek operations went into a scheduled turnaround, and returned to full production capacity in mid-October. Third quarter production at Christina Lake increased 24 percent due to increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake.

Royalties in the third quarter of 2010 increased by $34 million with Foster Creek achieving royalty payout status in the first quarter of 2010 and higher WTI prices used for calculating royalties resulting in higher royalty rates. Further information regarding the financial impact of achieving royalty payout status can be found in our MD&A for the three months ended March 31, 2010. For the third quarter of 2010, the effective royalty rate for Foster Creek was 17.9 percent (2009 - 3.0 percent) and 3.9 percent for Christina Lake (2009 – 2.9 percent).

Transportation and selling costs consist mainly of condensate, as blending condensate with bitumen enables the product to be transported. In the third quarter of 2010, our condensate volumes increased directly due to the higher production volumes. Our condensate costs were also higher due to an increase in the average cost of condensate. This resulted in transportation and selling costs increasing to $158 million in the third quarter of 2010 from $131 million in 2009.

Operating costs increased by $7 million due to higher repairs, maintenance and workover expenses, an increase in purchased fuel volumes, as well as increased field personnel in relation to phased expansions.

Nine Months Ended September 30, 2010 compared to 2009

(millions of Canadian dollars)	Nine Months Ended September 30, 2009 Net Revenues	Net Revenue Variances in: Price(1)	Volume	Royalties	Other(2)	**Nine Months Ended September 30, 2010 Net Revenues**
Foster Creek and Christina Lake	$ 905	50	234	(104)	257	**$ 1,342**

(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 selling expense.

In the first nine months our average crude oil sales price, excluding realized financial hedges, increased 13 percent to $58.63 per bbl compared to the same period in 2009 consistent with the price of WCS increasing year over year. Financial hedging activities for the nine months ended September 30, 2010 resulted in a realized loss of $9 million ($0.56 per bbl) compared to a gain of $45 million ($4.12 per bbl) in 2009.

Foster Creek production increased 47 percent primarily as a result of the phase D and E expansions which commenced production late in the first quarter of 2009 combined with well optimizations and 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.

Year to date royalties increased by $104 million compared to the same period in 2009 with Foster Creek achieving royalty payout status in the first quarter of 2010 along with a higher WTI price used for calculating royalties resulting in higher royalty rates. For the nine months ended September 30, 2010, the effective royalty rate for Foster Creek was 15.6 percent (2009 - 2.1 percent) and for Christina Lake was 4.1 percent (2009 – 1.9 percent).

Transportation and selling costs consist mainly of condensate, which increased by $265 million in the first nine months of 2010, as the volume of condensate required increased due to the higher production noted above as well as a higher average cost of condensate.

Operating costs increased by $33 million due to increased purchased fuel volumes, higher chemical costs, increased field personnel in relation to phased expansions and higher repairs and maintenance expenses.

DOWNSTREAM REFINING

Financial Results

(millions of dollars)	**Three Months Ended September 30** 2010	2009	**Nine Months Ended September 30** 2010	2009
Revenues	**$ 1,584**	$ 1,766	**$ 4,712**	$ 4,446
Expenses				
Operating	**117**	110	**366**	386
Purchased product	**1,499**	1,561	**4,408**	3,714
Operating Cash Flow	**$ (32)**	$ 95	**$ (62)**	$ 346

Refinery Operations [1]

	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	**2010**	2009
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**401**	425	**379**	409
Crude utilization *(%)*	**89**	94	**84**	90
Refined products *(Mbbls/d)*	**409**	451	**395**	433

(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 approximately 145,000 bbls/d of 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.

In the third quarter of 2010, our refineries operated at an average of 89 percent (year to date – 84 percent) of their capacity compared to 94 percent in the third quarter of 2009 (year to date – 90 percent). Utilization was lower in 2010 primarily due to planned turnarounds at the Wood River and Borger refineries, a power outage at Wood River and unplanned maintenance at both refineries. Also impacting year to date utilization was refinery optimization activities. Upon the completion of these turnaround and maintenance activities, utilization for September 2010 was 97 percent. No additional major turnarounds are planned for the remainder of 2010 at either refinery.

Market prices for refined products increased in the third quarter of 2010, which were more than offset by reduced volumes as a result of a prolonged planned turnaround at Borger in the quarter resulting in a 10 percent decrease in revenues. Revenues for the nine months ended September 30, 2010 compared to 2009 increased by six percent driven by increased refined product pricing consistent with increases in the benchmark prices.

Purchased product costs, which are determined on a first-in, first-out inventory valuation basis, decreased four percent in the third quarter of 2010 and year to date increased 19 percent compared to the same periods in 2009. We did not fully benefit from the wider light-heavy crude oil price differentials arising from pipeline disruptions during the third quarter of 2010 because, with the Keystone pipeline in initial start-up phase during the quarter there were longer than normal transportation times between the purchases of a portion of our Canadian heavy oil and the processing at the refinery. Purchased product, consisting mainly of crude oil, represented 93 percent of total expenses in the third quarter of 2010 which is consistent with the third quarter of 2009 and 92 percent of total expenses for the first nine months of 2010 compared to 91 percent in 2009.

Operating costs, consisting mainly of labour, utilities and supplies, increased six percent in the third quarter of 2010 due to costs related to the turnaround at Borger, unplanned maintenance and higher prices for utilities consumed at the refineries partially offset by a strengthened Canadian dollar. Operating costs decreased by five percent for the nine months ended September 30, 2010 due to the strengthening of the Canadian dollar in the periods offset by the higher costs that affected the third quarter.

Operating Cash Flow for the third quarter of 2010 was $127 million lower than the third quarter of 2009 mainly due to a planned turnaround at Borger which took longer than expected, a power outage at Wood River and unplanned maintenance at both refineries. Changes in Canadian heavy oil prices, which have historically taken one to two months to be reflected in our downstream financial results, were substantially deferred this quarter due to longer transportation times, as discussed above. Therefore, we expect that the impact of the wider light-heavy differentials during August and September 2010 will be reflected in our fourth quarter results.

2010 year to date Operating Cash Flow decreased by $408 million mainly due to the same factors that affected the change between third quarters, combined with the planned turnaround at Wood River earlier in 2010 in conjunction with the CORE project and refinery optimization activities.

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

INTEGRATED OIL DIVISION - OTHER PROPERTIES

The Integrated Oil Division also manages our 100 percent owned natural gas operations in Athabasca. Primarily as a result of natural decline, our production from Athabasca in the third quarter of 2010 decreased to 41 MMcf/d (2009 – 52 MMcf/d) and for the first nine months of 2010 decreased to 42 MMcf/d (2009 – 52 MMcf/d). In the fourth quarter of 2009, we sold our Senlac heavy oil assets. Senlac production in the third quarter of 2009 was 5,080 bbls/d and for the first nine months of 2009 was 3,339 bbls/d.

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Upstream				
Foster Creek	**$ 59**	$ 62	**$ 168**	$ 186
Christina Lake	**93**	53	**240**	158
Other	**5**	4	**47**	52
	157	119	**455**	396
Downstream Refining				
Wood River	**118**	266	**438**	736
Borger	**28**	25	**78**	72
	146	291	**516**	808
Total Integrated Oil Division	**$ 303**	$ 410	**$ 971**	$ 1,204

Our Upstream capital investment in 2010 was primarily focused on the continued development of the next phases of the Foster Creek and Christina Lake projects. Our current plan is to increase 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 the third quarter and year to date is lower than 2009 as we awaited regulatory approvals, which were received late in the third quarter, for the next phases of expansion (F, G and H). The majority of Foster Creek spending is related to drilling stratigraphic test wells, debottlenecking portions of the plant and spending in preparation for the next phase of expansion.

At Christina Lake, capital investment was higher in both the third quarter and year to date 2010 compared to 2009 due to increased pad drilling related to the phase C expansion and drilling stratigraphic test wells.

We have chosen to accelerate completion of Christina Lake phase D by approximately six months. Pending timely approvals, completion of Foster Creek phase F and Christina Lake phase E is planned to be accelerated by up to 12 months. Foster Creek phase F is awaiting final partner approvals while Christina Lake phase E requires regulatory and partner approvals.

The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion while wells drilled at Narrows Lake, Telephone Lake and other emerging projects have been drilled to assess the quality of our projects and to support regulatory applications for project approval. The following table summarizes the net stratigraphic wells drilled for the first nine months of each year:

	Nine Months Ended September 30	
	2010	2009
Foster Creek	**35**	33
Christina Lake	**12**	14
Narrows Lake	**18**	-
Telephone Lake	**26**	-
Other Emerging Projects	**7**	-
	98	47

Other capital investment in 2010 mainly relates to drilling of stratigraphic test wells and regulatory advancement of our new emerging oil sands plays. In 2009, other capital investment was focused on the continued development of the Athabasca gas and Senlac oil properties.

Our Downstream Refining capital investment in 2010 continued to focus on the CORE project at the Wood River refinery. For 2010, of the $438 million capital expenditures at Wood River, $372 million were related to the CORE project. At September 30, 2010, the CORE project is approximately 87 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 startup in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach US$3.7 billion (50 percent net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (50 percent net to Cenovus), or about 10 percent higher than originally forecast. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d.

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

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

CANADIAN PLAINS DIVISION

Crude Oil and NGLs

Financial Results

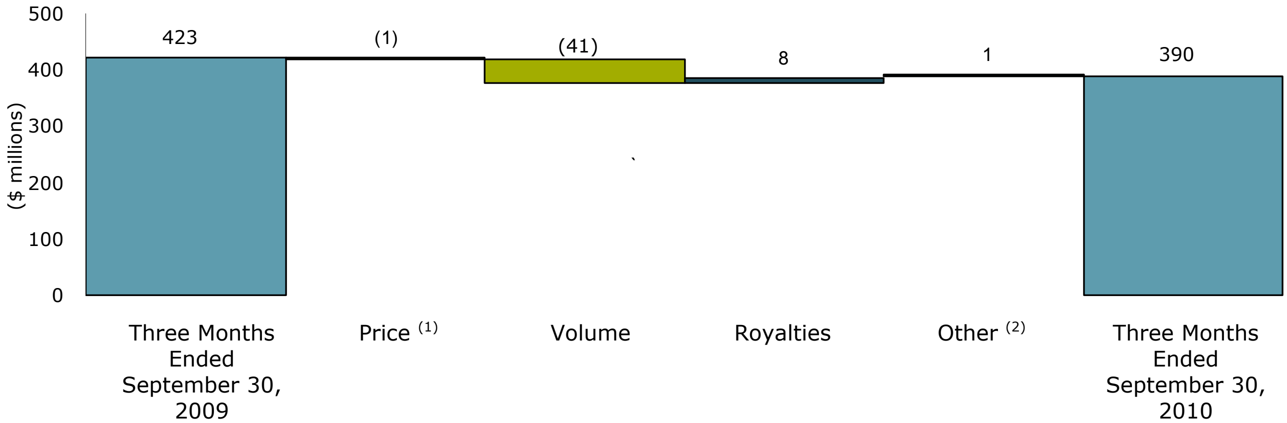
	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 435**	$ 489	**$ 1,419**	$ 1,274
Deduct (add)				
Realized financial hedging (gain) loss	**(13)**	-	**(7)**	(3)
Royalties	**58**	66	**204**	143
Net revenues	**390**	423	**1,222**	1,134
Expenses				
Production and mineral taxes	**7**	7	**22**	23
Transportation and selling	**45**	41	**165**	155
Operating	**76**	61	**230**	188
Operating Cash Flow	**$ 262**	$ 314	**$ 805**	$ 768

Production Volumes

	Three Months Ended September 30			Nine Months Ended September 30		
(bbls/d)	**2010**	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Heavy Oil						
Pelican Lake	**23,259**	**-9%**	25,671	**23,380**	**-7%**	25,228
Southern Alberta	**12,831**	**-4%**	13,318	**12,790**	**-9%**	13,983
Light and Medium Oil						
Weyburn	**17,621**	**-4%**	18,354	**17,795**	**-2%**	18,251
Southern Alberta	**10,385**	**-2%**	10,577	**10,363**	**-2%**	10,568
Other	**4,692**	**-16%**	5,573	**5,101**	**-10%**	5,653
NGLs	**1,172**	**-6%**	1,242	**1,165**	**-4%**	1,213
	69,960	**-6%**	74,735	**70,594**	**-6%**	74,896

Net Revenues Variance

Three Months Ended September 30, 2010 compared to 2009



(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 selling expense.

The average crude oil and NGLs sales price, excluding realized hedging, decreased slightly to $62.86 per bbl in the third quarter from $64.83 per bbl in 2009. During the third quarter, realized financial hedging gains were $13 million ($1.98 per bbl) compared to a gain of less than $1 million for 2009.

At Pelican Lake, volumes were nine percent lower in the third quarter mainly due to expected natural declines, partially offset by improved results from polymer flood performance and fewer operational issues. Southern Alberta oil production was down three percent primarily due to expected natural declines and production downtime. Production volumes at Weyburn were four percent lower in the third quarter due to natural declines and volume reductions resulting from unplanned outages which were partially offset by volume increases from well optimization and injection programs. Other production volumes were lower because of the divestiture of certain properties earlier in 2010, partially offset by new production in the Lower Shaunavon area of Saskatchewan. Production in the Lower Shaunavon area was interrupted by wet weather which prevented consistent access to production facilities.

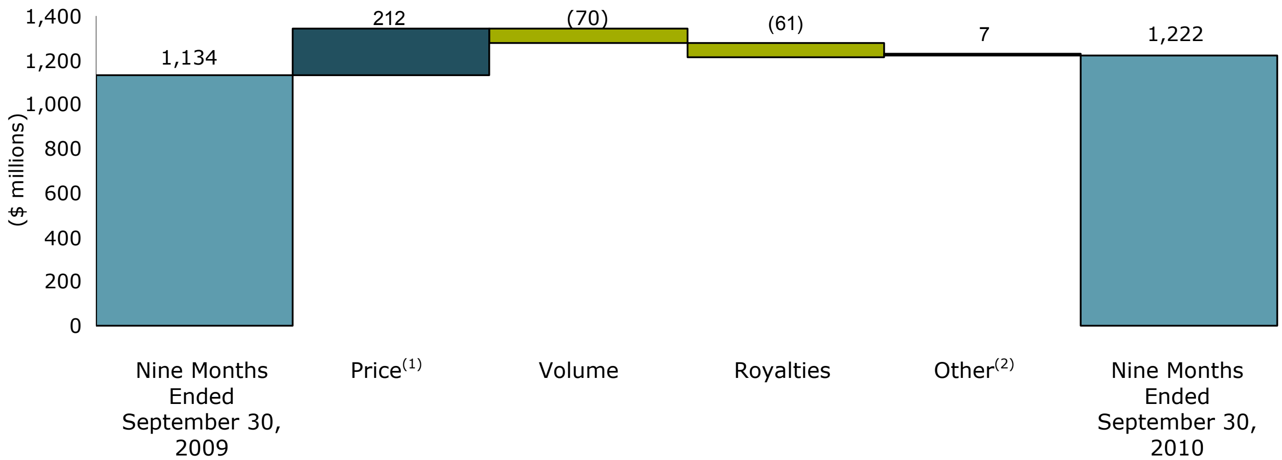
Royalties in the third quarter were $8 million lower than 2009 as a result of lower volumes as well as adjustments related to prior years. The effective crude oil royalty rate in the third quarter of 2010 was 14.9 percent (2009 – 15.0 percent).

Production and mineral taxes in the third quarter were consistent with the third quarter of 2009.

Transportation and selling costs in the third quarter increased by $4 million due to higher toll rates and a higher average cost of condensate, offset by lower volumes of condensate used for blending with heavy oil.

Operating costs increased by $15 million in the third quarter as a result of increased workover and repair and maintenance activity in all areas and increased polymer usage at Pelican Lake. NGLs are a byproduct obtained through the production of natural gas and therefore operating costs associated with the production of NGLs are included with natural gas.

Nine Months Ended September 30, 2010 compared to 2009



(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 selling expense.

For the first nine months of 2010 the average crude oil and NGLs sales price, excluding realized hedging, increased 20 percent to $66.59 per bbl compared to the same period in 2009, consistent with increases in the benchmark prices. During 2010, realized financial hedging gains were $7 million ($0.34 per bbl) compared to gains of $3 million ($0.17 per bbl) in 2009.

Production in 2010 was lower than the same period in 2009 due to expected natural declines as well as production downtime due to weather and operational challenges in Southern Alberta and Saskatchewan. Partially offsetting these reductions was increased production from well optimizations at Weyburn, new wells in Southern Alberta and the Lower Shaunavon area of Saskatchewan as well as better results from the polymer flood program at Pelican Lake. Lower production in the current year compared to last year was also due to dispositions of non-core properties.

Royalties for the nine months were $61 million higher than the same period in 2009 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 16.4 percent for the period compared to 13.2 percent for 2009. The higher royalty rate was partially offset by lower volumes.

Production and mineral taxes were consistent with the same period in 2009.

Transportation and selling costs in 2010 increased by $10 million as an increase in the average cost of condensate and higher transportation rates were partially offset by a decrease in the volume of condensate used for blending with heavy oil.

Operating costs increased by $42 million from 2009 as result of increased workover activity at Pelican Lake and Weyburn, higher repair and maintenance activity in all areas, higher chemical usage at Pelican Lake, higher trucking costs related to new production in Saskatchewan, and higher indirect costs.

Natural Gas

Financial Results

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2010	2009	**2010**	2009
Revenues	**$ 237**	$ 226	**$ 832**	$ 904
Deduct (add)				
Realized financial hedging (gain) loss	**(68)**	(311)	**(178)**	(847)
Royalties	**5**	1	**14**	12
Net revenues	**300**	536	**996**	1,739
Expenses				
Production and mineral taxes	**1**	3	**4**	13
Transportation and selling	**10**	12	**34**	37
Operating	**60**	60	**179**	184
Operating Cash Flow	**$ 229**	$ 461	**$ 779**	$ 1,505

Production Volumes

Natural Gas (MMcf/d)	Three Months Ended September 30			Nine Months Ended September 30		
	2010	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Southern Alberta	**666**	**-10%**	741	**680**	**-11%**	760
Other	**31**	**-16%**	37	**32**	**-18%**	39
	697	**-10%**	778	**712**	**-11%**	799

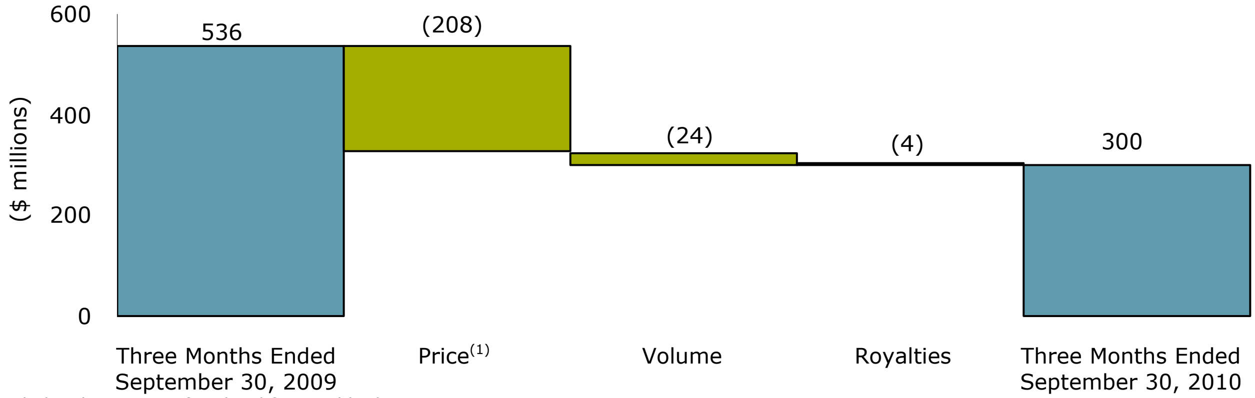
The increase in the average natural gas price, excluding realized financial hedges, to $3.70 per Mcf in the third quarter from $3.15 per Mcf in the third quarter of 2009 was consistent with the increase in the benchmark AECO price. The third quarter realized financial hedging gain of $68 million ($1.06 per Mcf) was $243 million lower than our gain of $311 million ($4.35 per Mcf) for the same period in 2009 as a result of our settled fixed price contract prices being approximately $3.00 per Mcf lower than the same period in 2009.

In the first nine months of 2010 the average natural gas price, excluding realized financial hedges, increased by $0.13 per Mcf when compared to the same period in 2009, which was consistent with the increase in the benchmark AECO price. Our realized financial gain in 2010 was $178 million ($0.91 per Mcf), a significant decrease from our 2009 gain of $847 million ($3.88 per Mcf). The change in our settled fixed price contracts, as discussed above, resulted in the decrease in realized hedging gains.

For details of the specific pricing on our hedging program, see the notes to our Interim Consolidated Financial Statements.

Net Revenues Variance

Three Months Ended September 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

Due to low commodity prices for natural gas, we chose to restrict capital spending on natural gas drilling, completion and tie-in activity in 2009 and 2010. As a result, production volumes for Southern Alberta decreased 10 percent in the third quarter of 2010 compared to the same period in 2009. Production was also reduced by unusually wet weather throughout 2010 which delayed our drilling and completion activities. The decrease was partially offset by increased production from our coal bed methane ("CBM") properties.

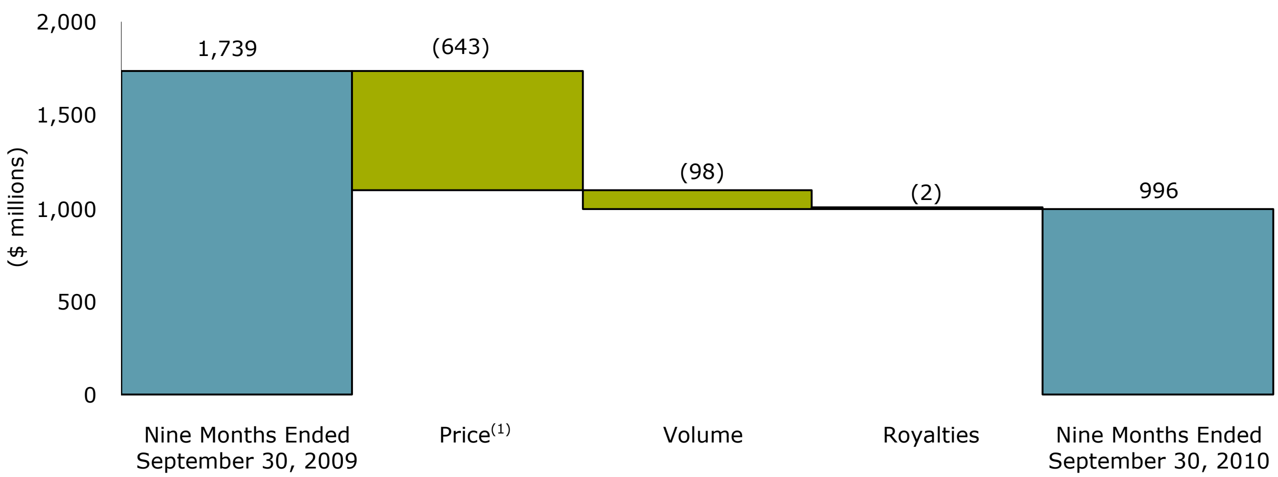
Royalties in the third quarter increased by $4 million compared to 2009 due primarily to a payment for royalties on previous years' production, resulting in an effective royalty rate of 2.3 percent (2009 – 0.4 percent).

Production and mineral taxes decreased by $2 million in the third quarter compared to 2009 primarily as a result of lower prices and volumes in 2010.

Transportation and selling costs in the third quarter were slightly lower compared with the same period in 2009 due to lower volumes and lower rates.

Operating expenses were consistent with the third quarter of 2009.

Nine Months Ended September 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

The cumulative impact of restricted natural gas capital spending in 2009 and 2010 has reduced production volumes in Southern Alberta by 11 percent year over year. Weather related delays in drilling and completion activities throughout 2010 further reduced production volumes. These decreases were partially offset by increases in CBM production and production from wells drilled in 2009 that were tied-in during 2010.

Increased royalties for the period were the result of payments for royalties on prior years' production, partially offset by lower volumes. The average royalty rate for the nine months ended September 30, 2010 was 1.7 percent (2009 – 1.4 percent).

Production and mineral taxes in the first nine months of 2010 were $9 million lower than 2009 due to lower prices and volumes in 2010.

Transportation and selling costs for the nine months ended September 30, 2010 were lower than 2009 due to lower rates and volumes.

Operating expenses for the period decreased three percent mainly as a result of reduced operations, specifically lower repairs and maintenance, lower field staff and salaries as well as lower processing costs.

Canadian Plains - Other

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 389**	$ 210	**$ 1,219**	$ 677
Expenses				
Operating	**3**	4	**15**	15
Purchased product	**380**	201	**1,186**	647
Operating Cash Flow	**$ 6**	$ 5	**$ 18**	$ 15

The Canadian Plains Division markets all of our crude oil and natural gas, including third party purchases and sales of product, in order to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification. The increase in both revenues and purchased product expenses for the three and nine month periods ended September 30, 2010 is largely the result of increased volumes for both crude oil and natural gas as well as higher commodity prices. Canadian Plains – Other also includes a small amount of third party processing fee income.

Capital Investment

Canadian Plains capital investment in the third quarter of 2010 was $166 million (2009 - $104 million) and for the nine months ended September 30, 2010 was $407 million (2009 - $438 million). The $62 million increase in capital investment during the third quarter of 2010 compared to 2009 is due to a planned increase in our investment activity for 2010, predominantly on crude oil as a result of higher prices. The $31 million decrease from year to date 2009 was primarily the result of unusually wet weather throughout 2010 which affected the timing of program execution.

For the nine months ended September 30, 2010, approximately 76 percent of our capital investment was on our crude oil properties (2009 – 50 percent) and primarily included capital maintenance and polymer injection investment in the Greater Pelican Region as well as drilling and facility work at Weyburn. We also invested in the oil program in our Southern Alberta properties as well as in the appraisal projects at Lower Shaunavon and Bakken in Saskatchewan, and Grand Rapids in the Greater Pelican Region. A total of 36 wells have been drilled in these areas this year. Our natural gas capital investment has been focused on our shallow gas projects in Suffield as well as our liquids rich deep gas projects in Southern Alberta.

The following table details the drilling activity of the Canadian Plains Division. Fewer 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.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(net wells drilled)	**2010**	2009	**2010**	2009
Crude oil	**59**	36	**119**	64
Natural gas	**251**	93	**329**	495
Recompletions	**359**	210	**768**	620
Stratigraphic test wells	**3**	-	**39**	18

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 37**	$ (392)	**$ 236**	$ (619)
Expenses ((add)/deduct))				
Operating	**4**	3	**5**	25
Purchased product	**(30)**	(44)	**(92)**	(82)
Depreciation, depletion and amortization	**4**	1	**24**	26
Segment Income (Loss)	**$ 59**	$ (352)	**$ 299**	$ (588)

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 mark-to-market gains and losses on long-term power purchase contracts and downstream crude oil supply positions. DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2010**	2009	**2010**	2009
General and administrative	**$ 49**	$ 49	**$ 160**	$ 142
Interest, net	**79**	64	**210**	166
Accretion of asset retirement obligation	**18**	11	**58**	34
Foreign exchange (gain) loss, net	**(24)**	120	**(23)**	211
(Gain) loss on divestitures and other	**-**	-	**8**	-
	$ 122	$ 244	**$ 413**	$ 553

Our year to date general and administrative expenses were higher than 2009 mainly because of higher salaries and benefits as we move to implement our 10 year strategic plan and complete the transition to a new independent company. For the third quarter of 2010 compared to 2009, these higher costs were offset by lower expenses related to long-term incentives.

Net interest in the third quarter of 2010 was $15 million higher than the third quarter of 2009 (year to date – increase of $44 million). Both of these increases are primarily the result of a higher average interest rate and higher average outstanding debt in 2010 compared to the proportionate share of Encana's debt allocated to Cenovus for the comparative periods in 2009. Also, the third quarter includes $5 million (year to date - $13 million) of financing cost amortization related to the setup of our debt financing programs. While our average interest rate during each period in 2010 was higher than 2009, our weighted average interest rate on outstanding debt at September 30, 2010 was 5.8 percent compared to 5.9 percent at September 30, 2009.

In the third quarter of 2010 we reported a foreign exchange gain of $24 million (2009 - loss of $120 million), the majority of which was unrealized. The strengthening of the Canadian dollar during the third quarter of 2010 led to an unrealized gain on our U.S. dollar debt, which was partially offset by an unrealized loss on our U.S. dollar partnership contribution receivable. For the nine months ended September 30, 2010 we recognized a foreign exchange gain of $23 million (2009 - loss of $211 million).

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 gain or loss 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 instrument agreements can be found in the notes to the Interim Consolidated Financial Statements.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues				
Crude Oil	**$ (55)**	$ 20	**$ 61**	$ (28)
Natural Gas	**122**	(368)	**267**	(509)
	67	(348)	**328**	(537)
Expenses	**5**	3	**7**	25
	62	(351)	**321**	(562)
Income Tax Expense (Recovery)	**17**	(99)	**90**	(160)
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 45**	$ (252)	**$ 231**	$ (402)

DEPRECIATION, DEPLETION and AMORTIZATION

(millions of dollars)	Three Months Ended September 30 2010	Three Months Ended September 30 2009	Nine Months Ended September 30 2010	Nine Months Ended September 30 2009
Upstream Canada	**$ 267**	$ 336	**$ 796**	$ 956
Downstream Refining	**44**	54	**144**	171
Corporate and Eliminations	**4**	1	**24**	26
	$ 315	$ 391	**$ 964**	$ 1,153

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 Canada DD&A in the third quarter and year to date were lower primarily as a result of a lower DD&A rate because of the addition of proved reserves at Christina Lake phase D at the end of 2009. Decreases to our Downstream Refining DD&A were primarily due to a strengthening of the Canadian dollar average exchange rate.

INCOME TAX

The third quarter income tax expense of $63 million was $16 million higher than the same period in 2009. Current income tax expense in the third quarter of 2010 was $30 million compared to $137 million in the third quarter of 2009, and future income tax expense was $33 million compared to a recovery of $90 million for 2009.

Year to date income tax expense of $189 million was $2 million lower than the same period in 2009. Current income tax expense for the period was $60 million (2009 - $386 million). Future tax expense for 2010 was $129 million compared to a recovery of $195 million for the period in 2009.

When comparing the third quarter and year to date amounts to the prior year, our current tax expense declined and our future tax expense increased primarily due to claims from tax pools that we received as a result of the Arrangement.

Our effective tax rate for the third quarter of 2010 was 22.0 percent (year to date - 17.0 percent) compared to 31.8 percent in 2009 (year to date – 19.8 percent). The decreases for the quarter and nine months ended are primarily due to the impact of permanent differences and the recognition of the future tax benefit arising from a loss 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;
- International financing; and
- Taxable foreign exchange (gains) losses 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.

LIQUIDITY AND CAPITAL RESOURCES

(millions of dollars)	Three Months Ended September 30 2010	2009	Nine Months Ended September 30 2010	2009
Net cash from (used in)				
Operating activities	**$ 645**	$ 1,414	**$ 1,936**	$ 2,889
Investing activities	**(299)**	(4,375)	**(1,139)**	(5,625)
Net cash provided (used) before Financing activities	**346**	(2,961)	**797**	(2,736)
Financing activities	**(288)**	3,035	**(475)**	2,754
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(3)**	(3)	**(13)**	(8)
Increase (decrease) in cash and cash equivalents	**$ 55**	$ 71	**$ 309**	$ 10

OPERATING ACTIVITIES

Net cash from operating activities decreased $769 million in the third quarter compared to 2009 and decreased $953 million in the first nine months compared to 2009 mainly because of lower Cash Flow. Cash Flow was $509 million during the third quarter (2009 - $924 million) and $1,767 million for the first nine months (2009 - $2,610 million). Reasons for this change are discussed under 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 $589 million at September 30, 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 for the three months ended September 30, 2010 decreased to $299 million from $4,375 million for the same period in 2009. Year to date net cash used in investing of $1,139 million was a decrease of $4,486 million from the same period in 2009. A substantial portion of the decrease in cash used in investing activities is related to cash that was restricted in 2009 as part of the Arrangement. Capital expenditures decreased in the third quarter to $484 million compared to $516 million in 2009 while year to date capital expenditures decreased by $203 million to $1,454 million compared to 2009. Total divestiture proceeds in 2010 of $312 million include $168 million which occurred in the third quarter. The changes to our capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

In September, Cenovus re-negotiated its $2.5 billion unsecured credit facility and combined the two existing tranches into a single tranche with a maturity of November 30, 2014.

Included in Cenovus's long-term debt obligations of $3,574 million at September 30, 2010, are $22 million in principal obligations related to the issuance of commercial paper. These amounts are fully backstopped by the Company's 4-year revolving syndicated credit facility, which expires in 2014 and has no repayment requirements within the next year. As a result, $2,478 million was available on the credit facility at September 30, 2010. We are currently in compliance with all of our covenants under this credit facility.

In the second quarter of 2010, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. In the third quarter of 2010, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$1.5 billion. At September 30, 2010, no notes have been issued under either prospectus. Further details can be found in the notes to the Interim Consolidated Financial Statements.

In each of the first three quarters of 2010, Cenovus declared and paid a dividend of $0.20 per share. Dividend payments for the first nine months of 2010 totaled $450 million. Declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash used in financing activities for the third quarter of 2010 was $288 million (2009 – generated $3,035 million). For the nine months ended September 30, 2010, $475 million of cash was used in financing activities (2009 – generated $2,754 million). A substantial portion of the decrease in cash generated in financing activities related to cash that was raised in 2009 and placed in escrow as part of the Arrangement. Our debt, including current portion, was $3,574 million as at September 30, 2010 compared with $3,656 million as at December 31, 2009.

FINANCIAL METRICS

	September 30, 2010	December 31, 2009
Debt to Capitalization	**26%**	28%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x

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 disposal of assets and other income/loss. Debt is defined as the current and long-term portions of long-term debt. These metrics are used to steward Cenovus's capital structure.

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 Interim 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 September 30, 2010 there were 752.0 million common shares outstanding and no first preferred shares or second preferred shares outstanding.

During the second quarter of 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 the Company, the additional common shares may be issued from treasury at the average market price or purchased on the market. For the period ended September 30, 2010, no common shares were issued from treasury to meet our DRIP requirements. Further information can be found on our website.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, demand charges on firm transportation agreements, building leases, capital commitments and marketing agreements. The Company expects its 2010 commitments to be funded from Cash Flow.

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.

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

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 risks (such as commodity price, foreign exchange and interest rates), credit and liquidity risks;
- 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 Corporate Risk Management 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.

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 our exploration, development and production of oil and gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval is generally required before initiating, advancing or changing operations projects. Further information regarding the status of each project can be found in the Divisional Results 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. These include proposed federal legislation and state actions in the U.S. to develop statewide or regional programs, each of which could impose reductions in GHG emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. 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 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. A fulsome assessment of potential regulations, our corporate strategy and performance is provided in our MD&A for the year ended December 31, 2009 and our response to the Carbon Disclosure Project can be found on our website. We will continue to provide quarterly updates to that information.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to integrating the principles of corporate responsibility into the way we conduct our business across all of our operations and operating in a responsible manner. We also recognize the importance of reporting to stakeholders in a transparent and accountable way. As part of this commitment we disclose not only information that's required by law and regulation, but also which more broadly describes activities, policies, opportunities and risk.

We are reviewing our existing Corporate Responsibility ("CR") policy 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.

In July 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 for download from 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.

ALBERTA'S ROYALTY FRAMEWORK

In the first and second quarters of 2010 the Alberta government released updates to the royalty structure in the province. Details of these updates can be found in the MD&A for the three months ended June 30, 2010. 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 Canadian Plains and any future shale oil developments in Alberta. Updates to the royalty curves for conventional oil and natural gas were included in our second quarter MD&A. The effective date of the new curves is January 1, 2011.

ALBERTA'S REGULATORY FRAMEWORK

As part of the Government of Alberta's competitiveness review, it initiated a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project"). The Project seeks to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment and ensuring public safety and conservation of resources. The Project involves engagement with a broad range of stakeholders, including industry, to ensure there is appropriate input for the development of an improved oil and gas regulatory system. The Project is expected to make final recommendations to the Government of Alberta for a renewed oil and gas regulatory system by December 31, 2010.

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act, 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. 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, the Lower Athabasca Regional Advisory Council ("RAC") provided its vision document to the Government of Alberta regarding the LARP, which is expected to be drafted and published for comment in early 2011. 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. 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.

ACCOUNTING POLICIES AND ESTIMATES

BASIS OF PRESENTATION

Our results for the nine month period from January 1 to September 30, 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, 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 Canadian GAAP.

The presentation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. 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.

Further information can be found in the notes to the Interim Consolidated Financial Statements.

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. The adoption of this standard did not impact the Company's Interim Consolidated Financial Statements for the period ended September 30, 2010. However, the adoption of this new standard will impact the accounting treatment of future business combinations.

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 Interim Consolidated Financial Statements for the period ended September 30, 2010.

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

RECENT ACCOUNTING PRONOUNCEMENTS

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

INTERNATIONAL FINANCIAL REPORTING STANDARDS

We will be required to report our results in accordance with IFRS beginning with the three month period ending March 31, 2011. We continue to be on schedule with our IFRS transition activities, and expect that the adoption of IFRS in 2011 will not have a significant impact or influence on our business, operations or strategies.

IFRS Accounting Policies

The IFRS accounting policies that we expect to use have not changed from those described in our MD&A for the three month period March 31, 2010 and for the year ended December 31, 2009. 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, including the new joint ventures standard that is expected to be published later in 2010.

It should be noted that our IFRS financial statements for 2011 must use the standards that are in effect on December 31, 2011. Therefore, the accounting policies that we have chosen and used for our draft IFRS opening balance sheet are subject to change. Our IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011.

IFRS Opening Balance Sheet

We have prepared an initial draft of our IFRS opening balance sheet at January 1, 2010, which is subject to further review by management and audit work by our external auditors before it is considered final. A summary of our significant IFRS 1 elections, as well as the significant estimated impacts are summarized below. Readers are cautioned that this information is unaudited and subject to change.

Upstream Property, Plant & Equipment ("PP&E")

To prepare the draft IFRS opening balance sheet, we chose to apply the IFRS 1 exemption for full cost oil & gas companies. Using the exemption, we re-classified the cost of our unproved properties from Upstream PP&E to a new asset category, Exploration and Evaluation. We allocated the remainder of our Upstream PP&E 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 and was consistent with the allocation process 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 as of January 1, 2010. In terms of our asset retirement obligation, the historical credit-adjusted risk free rates that are used in the calculation under Canadian GAAP were changed to their current rate under IFRS, which did not change the obligation significantly. As a result of applying the IFRS 1 exemption to our full cost pool, the change in the asset retirement obligation was recognized as a charge to equity.

Downstream PP&E

On transition to IFRS, IFRS 1 provides an option to elect to measure an asset at its fair value and use that fair value as its deemed cost. We elected this option for the downstream refineries and permanently reduced their carrying value by approximately $2.6 billion ($1.6 billion, after-tax). The reduction is the result of the fair value of the refineries being significantly less than their Canadian GAAP net book value at January 1, 2010. In addition, having revalued the refineries to their fair values, it was determined that the downstream deferred asset, which had a carrying value of $121 million at January 1, 2010, was fully impaired under IFRS.

Other Draft IFRS Opening Balance Sheet Matters

We have elected to apply the following additional exemptions in the preparation of our draft IFRS opening balance sheet:

- The cumulative foreign currency translation difference was reset to zero at January 1, 2010. This election had no impact on total shareholders' equity;
- All cumulative actuarial gains and losses on our defined benefit plans were recognized. There was no significant change to the pension liability;
- Retain our Canadian GAAP accounting for pre-transition date business combinations.

The adoption of IFRS has resulted in a change in the measurement of some of our stock-based compensation liability from the intrinsic value method to the fair value method. This did not result in a significant change to the liability.

Income Tax

The carrying amount of our future income tax on our draft IFRS opening balance sheet was directly impacted by the tax effects resulting from the changes noted above. The future income tax liability was reduced by approximately $1.0 billion on January 1, 2010.

Paid in Surplus

Under IFRS 1, the opening balance sheet adjustments are recorded directly to retained earnings, or if appropriate, another category of equity. As our Paid in Surplus balance reflects Cenovus's pre-Arrangement (December 1, 2009) retained earnings, we concluded that it is the most appropriate category of equity for the IFRS opening balance sheet adjustments. Therefore, in our draft IFRS opening balance sheet, our Paid in Surplus and our total shareholders' equity decreased by approximately $1.8 billion, primarily due to the after-tax effect of the fair value election on the refineries.

IFRS Results and Financial Statements

We are currently drafting our financial results under IFRS for the first and second quarters of 2010. We have also started drafting our IFRS financial statements and accompanying notes for the three month period ending March 31, 2011 as well as for the year ending December 31, 2011.

Internal Controls Over Financial Reporting and Disclosure Controls and Procedures

We have updated our internal controls documentation related to the monthly IFRS adjustments, including controls related to the completeness of the adjustments. We intend to update documentation related to external financial reporting processes, including disclosure controls and procedures, in the fourth quarter of 2010.

Financial Reporting Expertise

In terms of financial literacy, we continued our formal IFRS education sessions in the third quarter. Our education efforts will continue for the remainder of 2010 and into 2011. The education of our external stakeholders is expected to continue throughout 2010 and into 2011, as we calculate the quarterly adjustments from Canadian 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. We also have an extensive inventory of emerging oil sands projects, and we have a 100 percent working interest in many of these projects;
- 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;
- Internally funded growth through Free Cash Flow generation from our established crude oil and natural gas assets;
- Maintaining a lower risk profile through natural gas and downstream 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 modest increases in WTI prices while we are expecting the light-heavy differential to remain relatively strong compared to historical trends despite some weakening in 2011 as Canadian heavy crude supply grows in advance of new coking capacity and pipeline access to the Gulf of Mexico. Offsetting this is a relatively weak price outlook for natural gas and refining margins. The key challenges that need to be effectively managed to enable our growth are commodity price volatility, partner approvals, government project 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 Annual Information Form ("AIF") for the year ended December 31, 2009.

We expect our 2010 capital investment program to be funded from Cash Flow. We also have a plan to divest of certain non-core assets and to date have received proceeds of $312 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 ten 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 benefitted from this strategy in both 2009 and 2010, we cannot ensure 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.

Our Corporate Guidance, which was updated as at October 28, 2010, can be found on our website, at www.cenovus.com.

ADVISORY

FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and information about our current expectations, estimates and projections about the future, based on certain assumptions made by the Company in light of its experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking statements and information are typically identified by words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “forecast”, “target”, “project”, “objective”, “could”, “focus”, “vision”, “goal”, “proposed”, “scheduled”, “outlook” or similar expressions suggesting future outcomes or statements regarding an outlook, including statements about our strategy, our projected future value or net asset value, operating and financial results, schedules, land positions, production, including, without limitation, the stability or growth thereof, reserves and resources, material properties, uses and development of our technology, risk mitigation efforts, commodity prices, shareholder value, cash flow, funding alternatives, costs and expected impact of future commitments in respect of our ongoing operations generally and with respect to certain properties and interests held by Cenovus. Readers are cautioned not to place undue reliance on forward-looking statements and information as our actual results may differ materially from those expressed or implied. Please see our news release dated October 28, 2010, available on our website at www.cenovus.com and on SEDAR at www.sedar.com, for further discussion of circumstances that may cause actual results to differ materially from previously disclosed forward-looking statements.

Our forward-looking information in respect of anticipated 2010 cash flow, operating cash flow and pre-tax cash flow is based on actual production and commodity prices for the nine months ended September 30, 2010 and the following fourth quarter 2010 assumptions: achieving average production of approximately 128,800 bbls/d of crude oil and liquids and 690 MMcf/d of natural gas; average commodity prices of a WTI price of US$82.50 per bbl and a WCS price of US$64.00 per bbl for oil, a NYMEX price of US$3.75 per Mcf and AECO price of $3.25 per GJ for natural gas; an average U.S./Canadian dollar foreign exchange rate of $0.99 US$/CDN$; and an average Chicago 3-2-1 crack spread for 2010 of US$9.15 per bbl for refining margins; and an average number of outstanding shares of approximately 752 million.

Forward-looking statements involve a number of assumptions, risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The risk factors and uncertainties that could cause actual results to differ materially, and the factors or assumptions on which the forward-looking information is based, include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions inherent in our current guidance; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the effect 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, 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; success of hedging strategies; maintaining a desirable debt to cash flow ratio; accuracy of our reserves, resources and future production estimates; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; 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 the North American integrated heavy oil business and to obtain necessary regulatory approvals; the successful and timely implementation of capital projects; reliability of our assets; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; 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 synthetic crude oil; risks associated with technology and its application to our business; our ability to generate sufficient cash flow from operations to meet our current and future obligations; our ability to access external sources of debt and equity capital; 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 the interpretations of such laws or 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 us, 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, hostilities, civil insurrection and instability affecting countries in which we operate; risks associated with existing and potential future lawsuits and regulatory actions made against us; our financing plans and initiatives; the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders and our ability to realize the expected benefits of the Arrangement; our ability to obtain financing in the future on a stand alone basis; the historical financial information pertaining to our assets as operated by Encana prior to November 30, 2009 may not be representative of our results as an independent entity; our limited operating history as a separate entity and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. Readers are cautioned that the foregoing list is not exhaustive.

Many of these risk factors are discussed in further detail throughout this MD&A and on pages 73 to 80 of our AIF/Form 40-F, incorporated herein by reference, and Management's Discussion and Analysis for the year ended December 31, 2009, each as filed with Canadian securities regulatory authorities at www.sedar.com and the U.S. Securities and Exchange Commission at www.sec.gov, and available at www.cenovus.com. Readers are also referred to similar legal advisories contained in the Information Circular.

The forward-looking statements and information contained in this document, including the assumptions, risks and uncertainties underlying such statements, are made as of the date of this document and, except as required by law, we do not undertake any obligation to update publicly or to revise any of such information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this document are expressly qualified by this cautionary statement.

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 one barrel to six thousand cubic feet. 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 necessarily represent value equivalency at the well head.

ABBREVIATIONS

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	Bcf	billion cubic feet
boe	barrel of oil equivalent	MMbtu	million British thermal units
boe/d	barrel of oil equivalent per day	GJ	gigajoule

NON-GAAP MEASURES

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

REFERENCES TO CENOVUS

For convenience, references in this document to "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 regarding Cenovus Energy Inc. can be found on our website at www.cenovus.com.