Cenovus Energy Inc.

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

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("Cenovus", "we", "our", "us" or "the Company"), dated July 28, 2010, should be read with the unaudited Interim Consolidated Financial Statements for the period ended June 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 document.

Management is responsible for preparing the MD&A. Interim MD&As are approved by the Audit Committee of the Board of Directors of Cenovus (the "Board"), while the annual MD&A is approved by the Board.

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.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information; Crude Oil, NGLs and Natural Gas Conversions; Currency; Abbreviations; Non-GAAP Measures; and References to Cenovus contained in the Advisory section at the end of this document.

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

Cenovus is a Canadian oil company headquartered in Calgary, Alberta, which had a market capitalization of approximately $20 billion on June 30, 2010. In the second quarter of 2010, we had production of 253,733 BOE/d, 51 percent of which was crude oil and NGLs. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These properties are located in the Athabasca region in northeast Alberta 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, USA, enabling us to capture the full value from crude oil production through to refined products such as gasoline, diesel and jet fuel.

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. We have proven our expertise and low cost oil sands development approach, while 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 extracting the resource, increasing the amount recovered, reducing costs and improving the way we extract the resources. 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: Grand Rapids, Telephone Lake and Narrows Lake.

During the second quarter of 2010, we received approval from the 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. We intend to commence the pilot project before the end of 2010.

We have a 100 percent working interest in the Telephone Lake property, in the Greater Borealis Region. A joint application and environmental impact assessment ("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 hold a 50 percent interest, through our interest in the FCCL Partnership, 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 EIA and began public consultation for the project. Final terms of reference were issued by Alberta Environment in the second quarter. A joint application and EIA was filed at the end of the second quarter of 2010. The project is expected to include gross production capacity of up to 130,000 bbls/d in three phases, with the first phase expected to add approximately 40,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our land position in the oil sands. Most of the oil sands resource is undeveloped. In the second quarter of 2010, we issued news releases that highlight more 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 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 U.S. public company, enable us to mitigate commodity cycles by integrating our oil sands production with the sale of refined products. In addition to our strategy of growing net asset value as described here in, we will continue to pay meaningful dividends 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 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 natural gas liquids, 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 United States. 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 SECOND QUARTER 2010

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

- Production from our Foster Creek and Christina Lake oil sands projects increased by 42 percent;
- Net revenues increased by 13 percent, primarily as a result of higher crude oil prices and higher crude oil production;
- Upstream Operating Cash Flow decreased by $306 million because of lower natural gas volumes and prices, offset by higher crude oil volumes and prices;
- Operating Cash Flow from Downstream Refining operations decreased by $202 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds and refinery optimization;
- Realized financial hedging gains of $64 million, net of tax, compared to gains of $250 million, net of tax in 2009;
- Operating earnings decreased by $370 million, mostly due to lower Operating Cash Flows; and
- Declared and paid dividends of $150 million ($0.20 per share) in the second quarter of 2010.

The CORE project at Wood River continues to proceed with expected completion in mid-2011, with total costs expected to be within 10 percent of the US$3.6 billion budget (US$1.8 billion net to Cenovus). At June 30, 2010, construction on the CORE project was approximately 82 percent complete.

Work is currently progressing on the construction of Christina Lake phases C and D to assist in reaching our planned production goals. We are now targeting production from the next expansion phases at Foster Creek (phase F) and Christina Lake (phase E) to commence in 2014, one year earlier than initially planned. These accelerated planned production start dates are still pending timely regulatory and partner approvals.

To enable shareholders to understand our long-term growth potential, we released an independent evaluation of our bitumen economic contingent resources in April 2010 and our bitumen initially-in-place in June 2010. These evaluations, which were prepared by an independent qualified reserves evaluator, support management's belief that Cenovus has significant long term development potential.

In order to provide financial flexibility in the future, we have recently established two debt programs by way of base shelf prospectus filings. The Canadian shelf prospectus allows us to offer, from time to time, an aggregate principal amount of up to $1.5 billion in unsecured medium term notes. The U.S. shelf prospectus allows us to offer, from time to time, an aggregate principal amount up to US$1.5 billion in unsecured notes. Each of the shelf prospectuses has a term of 25 months.

OUR BUSINESS ENVIRONMENT

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

(Average benchmark prices)	**Six Months Ended June 30**		**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	2010	2009	**2010**	2010	2009	2009	2009	2009	2008	2008	2008
Crude Oil Prices *(US $/bbl)*											
West Texas Intermediate ("WTI")	**78.46**	51.68	**78.05**	78.88	76.13	68.24	59.79	43.31	59.08	118.22	123.80
Western Canada Select ("WCS")	**66.89**	43.50	**63.96**	69.84	64.01	58.06	52.37	34.38	39.95	100.22	102.18
Differential – WTI/WCS	**11.57**	8.18	**14.09**	9.04	12.12	10.18	7.42	8.93	19.13	18.00	21.62
WCS as percent of WTI	**85%**	84%	**82%**	89%	84%	85%	88%	79%	68%	85%	83%
Refining Margin 3-2-1 Crack Spreads [(1)] *(US $/bbl)*											
Chicago	**8.86**	10.35	**11.60**	6.11	5.00	8.48	10.95	9.75	6.31	17.29	13.60
Midwest Combined (Group 3)	**9.10**	9.39	**11.38**	6.82	5.52	8.06	9.16	9.62	6.00	14.38	13.47
Natural Gas Prices											
AECO *($/GJ)*	**4.36**	4.40	**3.66**	5.08	4.01	2.87	3.47	5.34	6.43	8.76	8.86
NYMEX *(US $/MMBtu)*	**4.69**	4.19	**4.09**	5.30	4.17	3.39	3.50	4.89	6.94	10.24	10.93
Basis Differential AECO/ NYMEX *(US $/MMBtu)*	**0.25**	0.37	**0.32**	0.19	0.19	0.67	0.39	0.35	1.10	1.28	1.71
Foreign Exchange											
Average US/Canadian dollar Exchange Rate	**0.967**	0.829	**0.973**	0.961	0.947	0.911	0.857	0.803	0.825	0.961	0.990

(1) 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.

The second quarter of 2010 saw large swings in the price of WTI. In early April the WTI spot price closed as high as US$86.84 per bbl but, impacted by the instability in global financial markets, deteriorated to a low of US$68.01 per bbl in late May before closing the quarter at US$75.63 per bbl. WTI averaged US$78.05 per bbl in the second quarter of 2010, consistent with the first quarter and approximately 31 percent higher than the same period in 2009. The average WTI price for the six months ended June 30, 2010 was approximately 52 percent higher than the same period in 2009, reflecting increased global crude oil demand, mainly from developing countries, and the effects of substantial cuts in OPEC production from 2008 which has resulted in decreased global inventory in 2010 when compared to 2009 levels.

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WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. The discount to WTI in the first two quarters of 2010 averaged US$11.57 per bbl which is wider than the same period last year. However, as a percentage of WTI, WCS remained consistent as the wider differential was offset by an increase in WTI prices. On a percentage basis, the differential in the second quarter of 2010 declined to recent historic average levels when compared with the previous quarter, attributable to the improvement in lighter crude oil demand, weak demand for heavy fuel oil in Asia and lower U.S. coker utilization due to poor economics. Compounding this global weakness was increased planned refinery maintenance in PADD II (Midwest U.S.) and increased unplanned upgrader outages in western Canada.

As shown in the table above, benchmark U.S. refining crack spreads improved in the second quarter of 2010 compared to the prior quarter as late May marks the beginning of summer driving season in North America, which historically has resulted in higher demand and higher prices for gasoline. Crack spreads for the second quarter of 2010 have improved compared to the same period in 2009 with the increase in consumer demand for refined products partly due to the improved economy in the United States. Consumer demand for refined products in the United States still remains below pre-recession levels.

In the second quarter of 2010, NYMEX natural gas prices improved over the second quarter of 2009 primarily due to the anticipation of hotter-than-normal summer weather and forecasts of an active hurricane season. Natural gas volumes in storage have decreased from the same period in 2009 but still remain well above the 5-year average.

During 2010, the Canadian dollar strengthened relative to the U.S. dollar, which increased the average exchange rate to 0.967 for the six months ended June 30, 2010 compared to 0.829 for the same period in 2009.

Our risk mitigation strategy has helped reduce our exposure to commodity price volatility. Realized hedging gains, after tax, in the second quarter were $64 million (year to date - $81 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 can be found 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 Canadian dollars, except per share amounts)	Six Months Ended June 30 **2010**	2009	Q2 **2010**	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008	Q2 2008
Net Revenues	**6,686**	5,511	**3,195**	3,491	3,005	3,001	2,818	2,693	3,946	5,753	4,424
Operating Cash Flow (1)	**1,503**	2,101	**665**	838	954	1,134	1,173	928	121	1,176	1,535
Cash Flow (1)	**1,258**	1,686	**537**	721	235	924	945	741	(209)	1,161	1,244
- per share – diluted (2)	**1.67**	2.25	**0.71**	0.96	0.31	1.23	1.26	0.99	(0.28)	1.54	1.66
Operating Earnings (1)	**495**	926	**142**	353	169	427	512	414	(159)	623	722
- per share – diluted (2)	**0.66**	1.23	**0.19**	0.47	0.23	0.57	0.68	0.55	(0.21)	0.82	0.96
Net Earnings	**697**	675	**172**	525	42	101	160	515	490	1,341	528
- per share – basic (2)	**0.93**	0.90	**0.23**	0.70	0.06	0.13	0.21	0.69	0.65	1.79	0.71
- per share – diluted (2)	**0.93**	0.90	**0.23**	0.70	0.06	0.13	0.21	0.69	0.65	1.78	0.71
Capital Investment	**923**	1,140	**430**	493	507	515	488	652	760	487	438
Free Cash Flow (1)	**335**	546	**107**	228	(272)	409	457	89	(969)	674	806
Cash Dividends (3)	**300**	-	**150**	150	159	-	-	-	-	-	-

(1) Non-GAAP measures which are defined within this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the Arrangement where 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 and second 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 Canadian dollars)		**Three months ended**	**Six months ended**
Net Revenues for the Periods Ended June 30, 2009		$ 2,818	$ 5,511
Increase (decrease) due to:			
Upstream Canada	Price	28	364
	Realized hedging	(268)	(543)
	Volume	27	45
	Royalties	(70)	(138)
	Other (1)	278	573
Downstream Refining		84	448
Corporate	Unrealized hedging	314	450
	Other	(16)	(24)
Net Revenues for the Periods Ended June 30, 2010		**$ 3,195**	**$ 6,686**

(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.

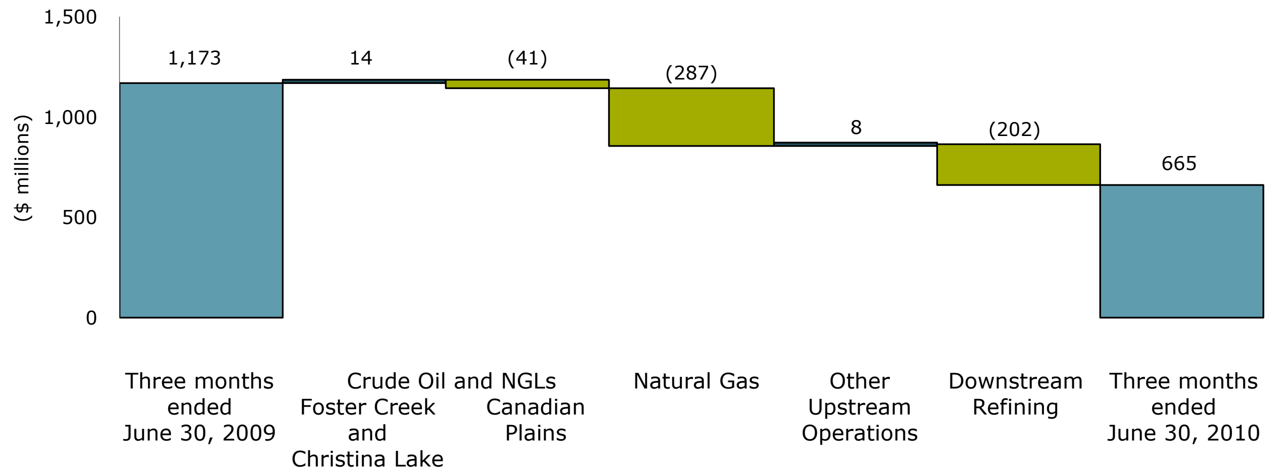
Net Revenues increased in the second quarter of 2010 and the six months ended June 30, 2010, primarily because of higher crude oil production volumes and prices partially offset by lower natural gas volumes and realized prices and higher royalties. Downstream Refining Net Revenues increased due to higher refined product prices partially offset by reduced volumes. Net Revenues also include unrealized hedge gains which increased in the second quarter and year over year. 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

(millions of Canadian dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	**2010**	2009
Crude Oil and NGLs				
Foster Creek and Christina Lake	**$ 176**	$ 162	**$ 391**	$ 233
Canadian Plains	**234**	275	**543**	454
Natural Gas	**268**	555	**582**	1,149
Other Upstream Operations	**11**	3	**17**	14
	689	995	**1,533**	1,850
Downstream Refining	**(24)**	178	**(30)**	251
Operating Cash Flow	**$ 665**	$ 1,173	**$ 1,503**	$ 2,101

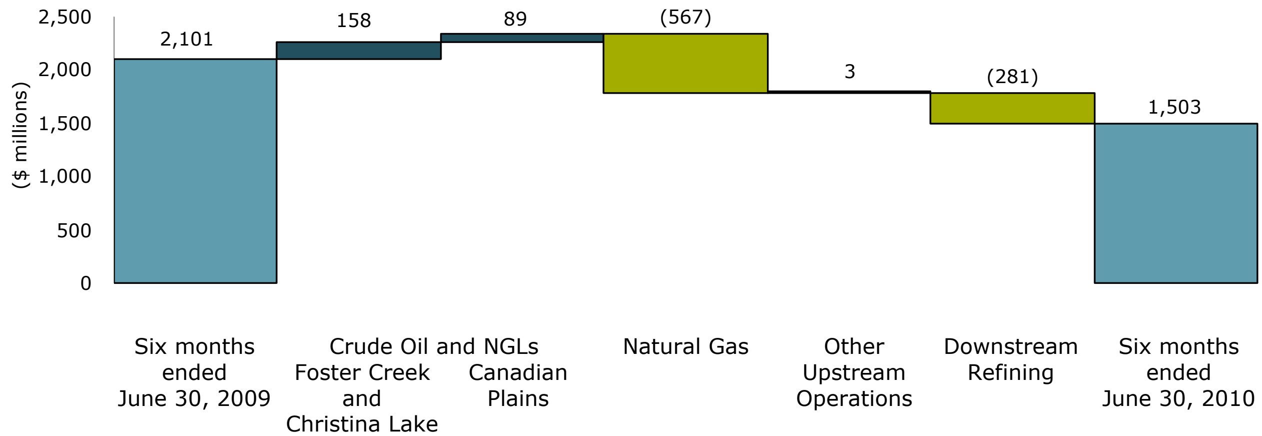
Operating Cash Flow is a non-GAAP measure defined as Net Revenues less Production and mineral taxes, Transportation and selling, Operating and Purchased product expenses. It is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our 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 June 30, 2010 compared to 2009



While we have seen increases in our Net Revenues in the three and six month periods in 2010, as shown above, Operating Cash Flows from our Upstream Canada segment decreased by $306 million in the second quarter of 2010 as a result of lower netbacks for natural gas resulting from decreased production and realized natural gas prices and lower netbacks for crude oil resulting from increased production volume and prices offset by higher royalties. Operating Cash Flows from our Downstream Refining segment decreased $202 million mainly due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds and refinery optimization. Details of the components that explain this decrease can be found in the Divisional Results section of this MD&A.

Six Months Ended June 30, 2010 compared to 2009



Operating Cash Flows for the six months ended June 30, 2010 decreased by $598 million. Upstream Canada decreased $317 million because of lower netbacks for natural gas resulting from decreased realized natural gas prices and production offset by higher netbacks for crude oil resulting from increased prices and production offset by higher royalties. Operating Cash Flows for Downstream Refining decreased $281 million due to increased crude oil purchased product costs and reduced crude utilization as a result of planned turnarounds and refinery optimization. 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 June 30		**Six Months Ended June 30**	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Cash From Operating Activities	**$ 471**	$ 793	**$ 1,291**	$ 1,475
(Add back) deduct:				
Net change in other assets and liabilities	**(13)**	(6)	**(28)**	(9)
Net change in non-cash working capital	**(53)**	(146)	**61**	(202)
Cash Flow	**$ 537**	$ 945	**$ 1,258**	$ 1,686

Three Months Ended June 30, 2010 compared to 2009

In the second quarter of 2010 Cash Flow decreased $408 million primarily due to:

- A 38 percent decrease in the realized average natural gas price, including the impact of hedges, to $5.00 per Mcf compared to $8.13 per Mcf;
- A decrease in operating cash flow from downstream operations of $202 million;
- An increase in Royalties of $70 million primarily as a result of Foster Creek achieving royalty payout and higher crude oil prices;
- Natural gas production declined 12 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production; and
- An increase in General and administrative and net interest expenses of $16 million.

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

- A $136 million decrease in current income tax expense primarily due to lower realized hedging gains and lower earnings from our downstream operations; and
- A 10 percent increase in our crude oil and NGLs production volumes.

Six Months Ended June 30, 2010 compared to 2009

Cash Flow for the six months ended June 30, 2010 decreased $428 million mainly due to:

- A 37 percent decrease in the realized average natural gas price, including the impact of hedges, to $5.40 per Mcf compared to $8.52 per Mcf;
- A decrease in operating cash flow from downstream operations of $281 million;
- An increase in Royalties of $138 million, primarily as a result of Foster Creek achieving payout and higher crude oil prices;
- Natural gas production declined 11 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production; and
- An increase in General and administrative and net interest expenses of $47 million.

The Cash Flow decreases above were offset by:

- A 24 percent increase in the realized average liquids selling price, including the impact of hedges, to $63.53 per bbl compared to $51.35 per bbl;
- Current income tax expense decreased $219 million primarily due to lower realized hedging gains and lower earnings from our downstream operations; and
- A 12 percent increase in our crude oil and NGLs production volumes.

OPERATING EARNINGS

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Net Earnings, as reported	**$ 172**	$ 160	**$ 697**	$ 675
(Add back) deduct:				
Unrealized mark-to-market accounting gain (loss), after-tax [1]	**16**	(214)	**186**	(150)
Non-operating foreign exchange gain (loss), after-tax [2]	**14**	(138)	**16**	(101)
Operating Earnings	**$ 142**	$ 512	**$ 495**	$ 926

(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 below that affected our Net Earnings also impacted our Operating Earnings.

The declines in our Operating Earnings for the three and six months ended June 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 Canadian dollars)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2009	$ 160	$ 675
Increase (decrease) due to:		
Net revenues	377	1,175
Expenses:		
Transportation and selling	(107)	(232)
Purchased product	(463)	(1,092)
Other expenses (1)	89	40
Depreciation, depletion and amortization	57	113
Income taxes	59	18
Net Earnings for the Periods Ended June 30, 2010	**$ 172**	**$ 697**

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

Net Earnings in the second quarter of 2010 increased by $12 million compared to the second quarter of 2009. The items identified above that reduced our Cash Flow in the second quarter also reduced our Net Earnings. There were other significant factors that increased our second quarter 2010 Net Earnings including:

- Unrealized mark-to-market gain, after-tax, of $16 million, compared to a $214 million loss, after-tax, in the second quarter of 2009;
- Unrealized foreign exchange loss of $31 million in the second quarter of 2010 compared to a loss in the second quarter of 2009 of $160 million;
- A decrease of $57 million in Depreciation, depletion and amortization ("DD&A"); and
- Future income tax recovery, excluding the impact of the unrealized financial hedging gains, in the second quarter of 2010 of $10 million, compared to a future income tax expense of $2 million in 2009.

For the six months ended June 30, 2010 Net Earnings increased by $22 million when compared to the same period in 2009. The items previously discussed that reduced our Cash Flow for the six months ended June 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 $186 million compared to a loss, after-tax of $150 million in 2009;
- DD&A expense decrease of $113 million;
- Unrealized foreign exchange gain of $1 million for year to date 2010 compared to a loss of $107 million in 2009; and
- Future income tax expense, excluding the impact of the unrealized financial hedging gains, of $23 million, compared to a future income tax recovery of $44 million in 2009.

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. 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. Overall our hedging program has had a positive effect on Net Earnings. The following information has been provided in order to provide information that is more comparable between periods:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Unrealized Mark-to-Market Gains (Losses), after-tax (1)	**$ 16**	$ (214)	**$ 186**	$ (150)
Realized Hedging Gains (Losses), after-tax (2)	**64**	250	**81**	448
Hedging Impacts in Net Earnings	**$ 80**	$ 36	**$ 267**	$ 298

(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.

NET CAPITAL INVESTMENT

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Integrated Oil - Upstream	**$ 147**	$ 122	**$ 298**	$ 277
Canadian Plains	**102**	99	**241**	334
Downstream Refining	**168**	265	**370**	517
Other	**13**	2	**14**	12
Capital Investment	**430**	488	**923**	1,140
Acquisitions	**47**	1	**47**	1
Divestitures	**(72)**	(3)	**(144)**	(3)
Net Capital Investment	**$ 405**	$ 486	**$ 826**	$ 1,138

Capital investment for both the three and six months ended June 30, 2010 were 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 capital investment is 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 second quarter of 2010 and sold certain Canadian Plains producing properties for net proceeds of $67 million while at the same time retaining our royalty interest in the area.

Acquisitions of $47 million in the second quarter of 2010 included the purchase of an interest in three sections of undeveloped land at Narrows Lake. Subsequent to June 30, 2010, we reached an agreement to transfer these lands to the FCCL Partnership. Other acquisitions during the second quarter included the purchase of undeveloped land and producing properties in our Canadian Plains Division.

In the first quarter of 2010, Cenovus sold certain wholly owned lands at the Narrows Lake property to the FCCL Partnership resulting in net proceeds of $72 million and reduced our working interest in Narrows Lake to 50 percent.

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 June 30		Six months ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Cash Flow	**$ 537**	$ 945	**$ 1,258**	$ 1,686
Capital Investment	**430**	488	**923**	1,140
Free Cash Flow	**$ 107**	$ 457	**$ 335**	$ 546

In the second quarter of 2010, Free Cash Flow was $350 million lower than the same period in 2009, while for the first six months of 2010, Free Cash Flow decreased by $211 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)	**Q2 2010**	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008	Q2 2008
Crude Oil									
Foster Creek	**51,010**	51,126	47,017	40,367	34,729	28,554	29,241	27,289	21,244
Christina Lake	**7,716**	7,420	7,319	6,305	6,530	6,635	6,170	4,620	3,670
Weyburn	**18,043**	17,722	18,536	18,354	18,368	18,028	17,408	17,634	17,178
Pelican Lake	**23,319**	23,565	23,804	25,671	23,989	26,029	24,975	27,826	27,306
Southern Alberta	**22,458**	23,790	23,729	23,895	24,089	25,404	25,509	25,654	27,041
Canadian Plains – Other	**4,854**	5,770	5,506	5,573	5,806	5,862	6,090	6,166	6,470
Integrated Oil – Senlac	**-**	-	2,221	5,080	2,574	2,334	2,623	3,135	3,281
NGLs	**1,166**	1,156	1,183	1,242	1,184	1,213	1,158	1,167	1,204
	128,566	130,549	129,315	126,487	117,269	114,059	113,174	113,491	107,394

When compared to the same periods in 2009, overall crude oil and NGLs production increased 10 percent in the second quarter and 12 percent year to date to 129,551 bbls/d. Quarterly production volumes increased 47 percent at Foster Creek (year to date – 61 percent) and 18 percent at Christina Lake (year to date – 15 percent). These increases were partially offset by declines at our other properties, as well as the sale of certain non-core properties in the second quarter of 2010 and our Senlac property in the fourth quarter of 2009. Further detail on the changes in our production between the periods can be found in the Divisional Results section of this MD&A.

Natural Gas Production Volumes

(MMcf/d)	**Q2 2010**	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008	Q2 2008
Southern Alberta	**676**	699	719	741	761	777	803	815	838
Canadian Plains – Other	**32**	34	34	37	41	39	40	44	48
Integrated Oil – Other	**43**	42	44	52	54	50	62	88	99
	751	775	797	830	856	866	905	947	985

When compared to the same periods in 2009, overall natural gas production decreased 12 percent in the second quarter and 11 percent year to date to 762 MMcf/d. Quarterly production volumes declined 11 percent in Southern Alberta (year to date – 11 percent) compared to the same quarter of 2009. The production decline was the result of expected natural production declines, as well as the cumulative impact of lower capital spending on natural gas drilling and tie-in activity throughout 2009 and weather related delays in the first half of 2010. Further detail on our year to date 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 June 30			
	2010		2009	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$ 59.50**	**$ 3.78**	$ 57.81	$ 3.80
Royalties	**9.93**	**0.07**	5.14	0.01
Production and mineral taxes	**0.71**	**(0.04)**	0.61	0.07
Transportation and selling	**1.94**	**0.15**	1.98	0.16
Operating expenses	**12.07**	**0.94**	10.61	0.83
Netback excluding Realized Financial Hedging	**34.85**	**2.66**	39.47	2.73
Realized Financial Hedging Gain (Loss)	**(0.40)**	**1.22**	1.54	4.33
Netback including Realized Financial Hedging	**$ 34.45**	**$ 3.88**	$ 41.01	$ 7.06

Our 2010 second quarter average netback for liquids, excluding realized financial hedging, decreased by $4.62 per bbl. The decrease was mostly related to higher royalties and partly due to higher operating expenses. Our average netback for natural gas, excluding realized financial hedging, was consistent with 2009.

Operating Netbacks – Year to Date

	Six Months Ended June 30			
	2010		2009	
	Liquids ($/bbl)	**Natural Gas** ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$ 64.11**	**$ 4.53**	$ 48.97	$ 4.64
Royalties	**9.37**	**0.11**	4.11	0.08
Production and mineral taxes	**0.65**	**0.02**	0.77	0.06
Transportation and selling	**1.87**	**0.18**	1.84	0.17
Operating expenses	**11.75**	**0.94**	11.13	0.88
Netback excluding Realized Financial Hedging	**40.47**	**3.28**	31.12	3.45
Realized Financial Hedging Gain (Loss)	**(0.58)**	**0.87**	2.38	3.88
Netback including Realized Financial Hedging	**$ 39.89**	**$ 4.15**	$ 33.50	$ 7.33

In the first six months of 2010, our average netback for liquids, excluding realized financial hedging, increased by $9.35 per bbl primarily due to an increase in prices partially offset by higher royalties. 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. 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, USA, respectively.

Highlights of the second quarter include significant increases in production at both Foster Creek and Christina Lake, as well as significant progress related to the development of our other oil sands projects.

FOSTER CREEK AND CHRISTINA LAKE

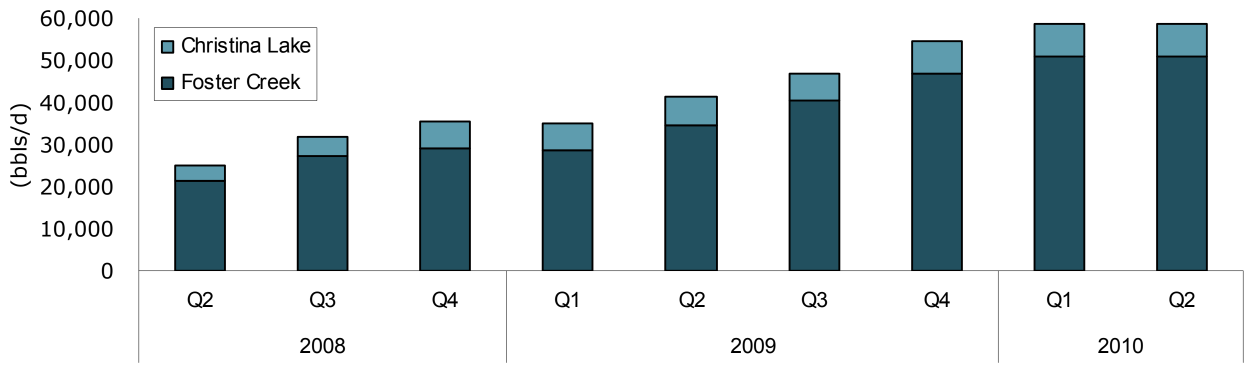
Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 510**	$ 309	**$ 1,030**	$ 485
Deduct (add)				
Realized financial hedging (gain) loss	**3**	(16)	**8**	(45)
Royalties	**46**	2	**73**	3
Net revenues	**461**	323	**949**	527
Expenses				
Transportation and selling	**224**	116	**437**	199
Operating	**61**	45	**121**	95
Operating Cash Flow	**$ 176**	$ 162	**$ 391**	$ 233

Production Volumes

	Three Months Ended June 30			Six Months Ended June 30		
Crude oil *(bbls/d)*	**2010**	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Foster Creek	**51,010**	**47%**	34,729	**51,067**	**61%**	31,658
Christina Lake	**7,716**	**18%**	6,530	**7,569**	**15%**	6,582
	58,726	**42%**	41,259	**58,636**	**53%**	38,240

Production Volumes by Quarter



Net Revenues Variance

Three Months Ended June 30, 2010 compared to 2009

(millions of Canadian dollars)	Three Months Ended June 30, 2009 Net Revenues	Net Revenue Variances in: Price[1]	Volume	Royalties	Other[2]	**Three Months Ended June 30, 2010 Net Revenues**
Foster Creek and Christina Lake	$ 323	(19)	94	(44)	107	**$ 461**

(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 second quarter the average crude oil sales price, excluding realized financial hedges, of $54.78 per bbl was consistent with the 2009 price of $54.88 per bbl. Although the price of WCS in 2010 was higher than 2009, it was offset by a shift in condensate prices trading at a premium to WTI in the second quarter of 2010 compared to a discount in the same quarter of 2009. In the second quarter of 2010, financial hedging activities resulted in a realized loss of $3 million ($0.47 per bbl) compared to a gain of $16 million ($4.41 per bbl) in the second quarter of 2009.

Production at Foster Creek increased 47 percent in the second quarter of 2010 compared to 2009 as a result of the ramp up of production from the phase D and E expansions combined with well optimizations and increased production from wedge wells. Second quarter production at Christina Lake increased 18 percent compared to 2009 as a result of the ramp up of production from the phase B expansion and well optimizations.

Royalties in the second quarter of 2010 increased by $44 million compared to the same period in 2009 as Foster Creek achieved royalty payout status in the first quarter of 2010 and higher WTI prices resulted 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 second quarter of 2010, the effective royalty rate for Foster Creek was 19.0 percent compared to 1.5 percent in the second quarter of 2009. For Christina Lake, the royalty rate was 4.4 percent in the second quarter of 2010 compared to 1.6 percent for the same period in 2009.

Transportation and selling costs are comprised mostly of condensate costs, as blending condensate with bitumen enables the product to be transported. In the second quarter of 2010, our condensate volumes increased directly due to the higher production volumes. Our condensate costs were also higher due to a 33 percent increase in the average cost of condensate. This resulted in transportation and selling costs increasing to $224 million in the second quarter of 2010 from $116 million in the second quarter of 2009.

Operating costs increased to $61 million in the second quarter of 2010 compared to $45 million in 2009 due to an increase in purchased fuel volumes, as well as higher chemical costs and increased field personnel as a result of higher production.

Six Months Ended June 30, 2010 compared to 2009

(millions of Canadian dollars)	Six Months Ended June 30, 2009 Net Revenues	Net Revenue Variances in: Price(1)	Volume	Royalties	Other(2)	**Six Months Ended June 30, 2010 Net Revenues**
Foster Creek and Christina Lake	$ 527	90	170	(70)	232	**$ 949**

(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 six months our average crude oil sales price, excluding realized financial hedges, increased 30 percent to $58.83 per bbl compared to the same period in 2009 consistent with the price of WCS increasing year over year. Financial hedging activities for the first half of 2010 resulted in a realized loss of $8 million ($0.72 per bbl) compared to a gain of $45 million ($6.76 per bbl) in 2009.

Foster Creek production increased 61 percent for the six months ended June 30, 2010 compared to 2009 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 15 percent increase in production at Christina Lake for the first six months of 2010 compared to 2009 was a result of the ramp up of production from the phase B expansion and well optimizations.

Year to date royalties increased by $70 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 resulting in higher royalty rates. In the first half of 2010, the effective royalty rate for Foster Creek was 14.5 percent (2009 - 1.4 percent) and for Christina Lake was 4.2 percent (2009 – 1.3 percent).

Transportation and selling costs comprised mostly of condensate costs, which increased to $437 million in the first six months of 2010, as the volume of condensate required increased due to the higher production noted above and the average cost of condensate increased 42 percent.

Operating costs for the first six months of 2010 increased to $121 million compared to $95 million for the same period in 2009 due to increased purchased fuel volumes, as well as higher chemical costs and increased field personnel as a result of higher production.

DOWNSTREAM REFINING

Financial Results

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 1,610**	$ 1,526	**$ 3,128**	$ 2,680
Expenses				
Operating	**110**	129	**249**	276
Purchased product	**1,524**	1,219	**2,909**	2,153
Operating Cash Flow	**$ (24)**	$ 178	**$ (30)**	$ 251

Refinery Operations [1]

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	**2010**	2009
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**379**	404	**367**	401
Crude utilization *(%)*	**84**	89	**81**	89
Refined products *(Mbbls/d)*	**398**	428	**388**	425

(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 coker and refinery expansion project ("CORE") in 2011 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 second quarter of 2010, our refineries operated at an average of 84 percent (year to date – 81 percent) of their capacity compared to 89 percent in the second quarter of 2009 (year to date – 89 percent). Utilization is lower in 2010 primarily due to planned turnarounds at the Wood River and Borger refineries and refinery optimization.

Market prices for refined products increased in the second quarter of 2010, which were partially offset by reduced volumes as a result of planned turnarounds in the quarter resulting in a six percent increase in Revenues between periods. Revenues for the six months ended June 30, 2010 compared to 2009 increased by 17 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 basis, increased 25 percent in the second quarter of 2010 and year to date 35 percent compared to the same periods in 2009. Purchased product, consisting mainly of crude oil, represented 93 percent of total expenses in the second quarter of 2010 compared to 90 percent in the second quarter of 2009 and 92 percent of total expenses for the first six months of 2010 compared to 89 percent in 2009.

Operating costs, consisting mainly of labour, utilities and supplies, decreased 15 percent in the second quarter of 2010 and decreased by 10 percent for the six months ended June 30, 2010 due to the strengthening of the average Canadian dollar exchange rates in the periods offset by costs related to the turnarounds at both refineries and higher prices for utilities consumed at the refineries.

Operating Cash Flow for the second quarter of 2010 was $202 million lower than the second quarter of 2009 mainly due to increased crude oil purchased product costs more than offsetting higher refined product sales prices. The decrease in Operating Cash Flow also reflected the impact of the planned turnarounds at both Wood River and Borger and lower refinery utilization. 2010 year to date Operating Cash Flow decreased by $281 million mainly due to the same factors that affected the change between second quarters.

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 declines, our production from Athabasca in the second quarter of 2010, decreased to 43 MMcf/d (2009 – 54 MMcf/d) and for the first six 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 second quarter of 2009 was 2,574 bbls/d and for the first six months of 2009 was 2,455 bbls/d.

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

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Upstream				
Foster Creek	**$ 52**	$ 59	**$ 109**	$ 124
Christina Lake	**84**	49	**147**	105
Other	**11**	14	**42**	48
	147	122	**298**	277
Downstream Refining				
Wood River	**140**	239	**321**	470
Borger	**28**	26	**49**	47
	168	265	**370**	517
Total Integrated Oil Division	**$ 315**	$ 387	**$ 668**	$ 794

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 completion of Christina Lake phase C in 2011 and phase D in 2013.

Foster Creek capital investment in the second quarter and year to date is lower than 2009 as we await regulatory approvals for the next phases of expansion. The majority of Foster Creek spending is related to drilling stratigraphic test wells, debottlenecking aspects of the plant and spending in preparation for the next phase of expansion.

At Christina Lake, capital investment was higher in both the second 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 regulatory and partner approvals, completion of Foster Creek phase F and Christina Lake phase E is planned to be accelerated by up to 12 months.

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 six months of each year:

	Six Months Ended June 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 sand 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 $321 million capital expenditures at Wood River, $262 million were related to the CORE project. At June 30, 2010, the CORE project is approximately 82 percent complete and is anticipated to be completed and in operation mid-year 2011, with total costs expected to be within 10 percent of the US$3.6 billion budget (US$1.8 billion net to Cenovus). 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 capital investment was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CANADIAN PLAINS DIVISION

Crude Oil and NGLs

Financial Results

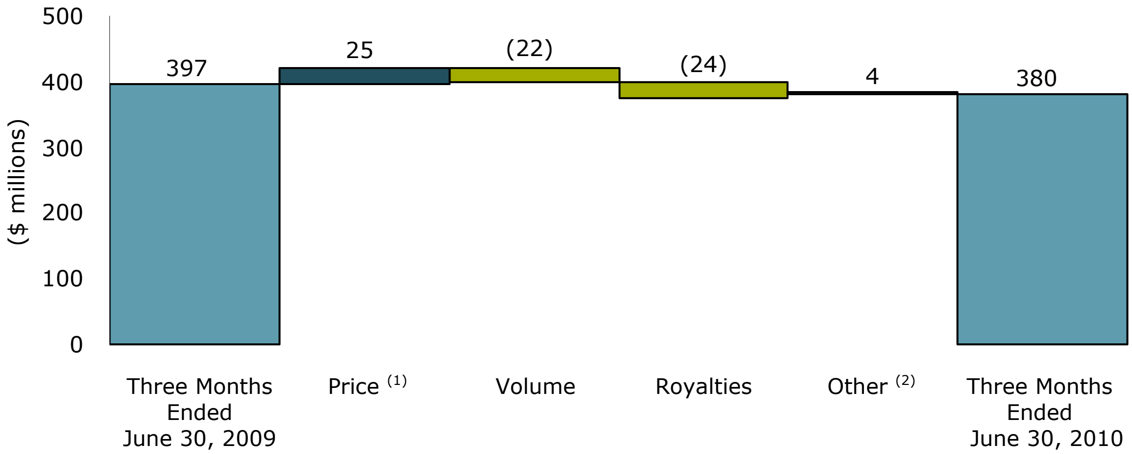
	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 454**	$ 445	**$ 984**	$ 785
Deduct (add)				
Realized financial hedging (gain) loss	**2**	-	**6**	(3)
Royalties	**72**	48	**146**	77
Net revenues	**380**	397	**832**	711
Expenses				
Production and mineral taxes	**8**	7	**15**	16
Transportation and selling	**56**	51	**120**	114
Operating	**82**	64	**154**	127
Operating Cash Flow	**$ 234**	$ 275	**$ 543**	$ 454

Production Volumes

	Three Months Ended June 30			Six Months Ended June 30		
(bbls/d)	**2010**	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Heavy Oil						
Pelican Lake	**23,319**	**-3%**	23,989	**23,441**	**-6%**	25,004
Southern Alberta	**12,253**	**-10%**	13,654	**12,769**	**-11%**	14,320
Light and Medium Oil						
Weyburn	**18,043**	**-2%**	18,368	**17,883**	**-2%**	18,199
Southern Alberta	**10,205**	**-2%**	10,435	**10,352**	**-1%**	10,456
Other	**4,854**	**-16%**	5,806	**5,309**	**-8%**	5,801
NGLs	**1,166**	**-2%**	1,184	**1,161**	**-3%**	1,199
	69,840	**-5%**	73,436	**70,915**	**-5%**	74,979

Net Revenues Variance

Three Months Ended June 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, increased seven percent to $63.53 per bbl in the second quarter from $59.42 per bbl in 2009 consistent with increases in the benchmark prices. During the second quarter, realized financial hedging losses were $2 million ($0.34 per bbl) compared to a gain of less than $1 million for 2009 ($0.04 per bbl).

Production volumes at Weyburn were two percent lower in the second quarter compared to 2009 as volume reductions due to maintenance downtime offset volume increases from well optimization and injection programs. At Pelican Lake, volumes were three percent lower in the second quarter mainly due to expected natural declines offset by the increase in production due to less maintenance downtime in 2010. Southern Alberta oil production was down seven percent when compared to the same period in the prior year primarily due to expected natural declines and production downtime resulting from weather. Other production volumes were lower primarily because of the divestiture of certain non-core properties, which prior to their divestiture had production of 441 bbls/d in the second quarter of 2010 (2009 – 2,060 bbls/d), partially offset by new production in the Lower Shaunavon area of Saskatchewan.

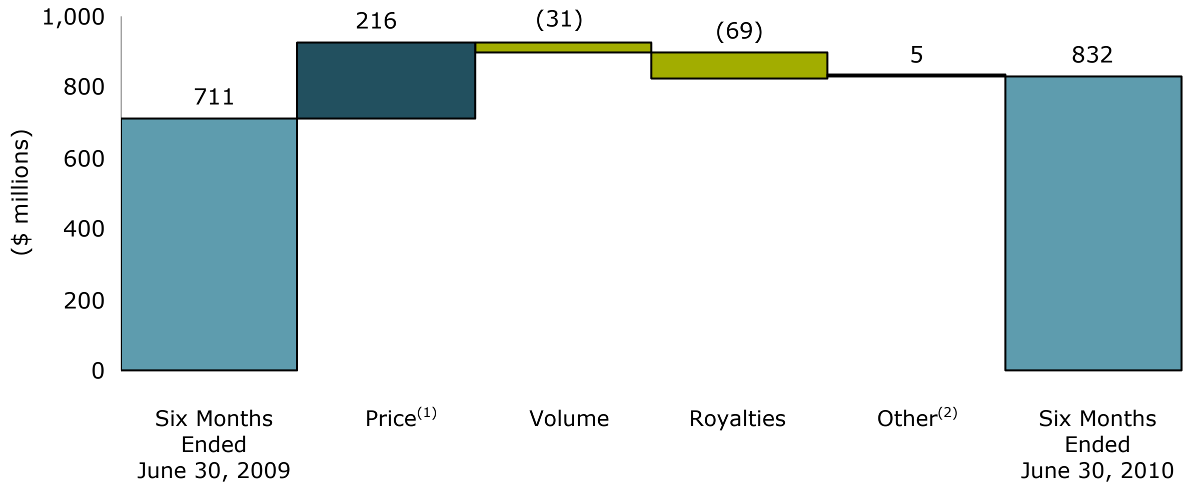
Royalties in the second quarter of $72 million were $24 million higher than the same period in 2009 as a result of higher commodity prices, as well as higher royalty rates arising from the higher commodity prices. The effective crude oil royalty rate in the second quarter of 2010 was 17.6 percent (2009 – 13.0 percent).

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

Transportation and selling costs in the second quarter increased by $5 million as the 24 percent increase in the average cost of condensate was partially offset by a 12 percent decrease in the volume of condensate used for blending with heavy oil.

Operating costs increased to $82 million in the second quarter from $64 million in the second quarter of 2009 as a result of increased workover and repair and maintenance activity, higher electricity rates and increased chemical 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.

Six Months Ended June 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 six months the average crude oil and NGLs sales price, excluding realized hedging, increased 34 percent to $68.44 per bbl compared to the same period in 2009, consistent with increases in the benchmark prices. During the first half of 2010, realized financial hedging losses were $6 million ($0.47 per bbl) compared to a gain of $3 million ($0.24 per bbl) in the first six months of 2009.

Production for the first half of 2010 was lower than the same period in 2009 due to expected natural declines, production downtime due to weather and operational challenges in Southern Alberta. Partially offsetting these reductions were increased production from both well optimizations at Weyburn and from new wells in Southern Alberta and the Lower Shaunavon area of Saskatchewan. Non-core properties were divested in the second quarter of 2010, which prior to their divestiture had year to date production of 895 bbls/d (2009 – 1,825 bbls/d).

Royalties for the six months of $146 million were $69 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 the effective royalty rate for the period increasing to 17.0 percent from 11.9 percent for the same period in 2009.

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

Transportation and selling costs in the first half of 2010 increased by $6 million compared to the same period in 2009 as a 26 percent increase in the average cost of condensate was offset by a 16 percent decrease in the volume of condensate used for blending with heavy oil.

2010 year to date Operating costs increased to $154 million from $127 million in 2009 as result of increased workover and repair and maintenance activity, higher chemical usage at Pelican Lake, increased electricity prices and indirect costs.

Natural Gas

Financial Results

(millions of Canadian dollars)	Three Months Ended June 30 2010	Three Months Ended June 30 2009	Six Months Ended June 30 2010	Six Months Ended June 30 2009
Revenues	**$ 247**	$ 275	**$ 595**	$ 678
Deduct (add)				
Realized financial hedging (gain) loss	**(76)**	(283)	**(110)**	(536)
Royalties	**3**	3	**9**	11
Net revenues	**320**	555	**696**	1,203
Expenses				
Production and mineral taxes	**(2)**	6	**3**	10
Transportation and selling	**10**	12	**24**	25
Operating	**60**	60	**119**	124
Operating Cash Flow	**$ 252**	$ 477	**$ 550**	$ 1,044

Production Volumes

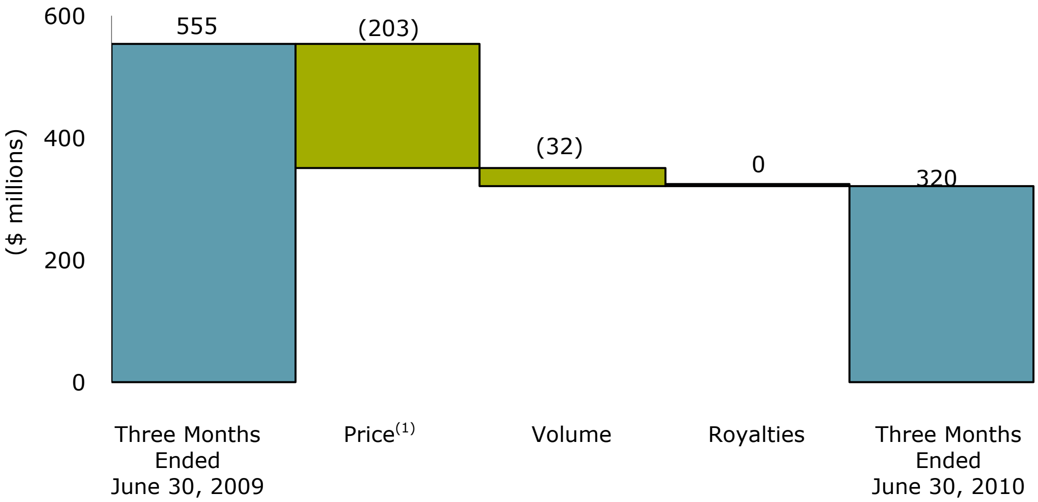
	Three Months Ended June 30			Six Months Ended June 30		
Natural Gas (MMcf/d)	**2010**	**2010 vs 2009**	2009	**2010**	**2010 vs 2009**	2009
Southern Alberta	**676**	**-11%**	761	**688**	**-11%**	769
Other	**32**	**-22%**	41	**32**	**-20%**	40
	708	**-12%**	802	**720**	**-11%**	809

The increase in the average natural gas price, excluding realized financial hedges, to $3.84 per Mcf in the second quarter from $3.77 per Mcf in the second quarter of 2009 was consistent with the increase in the benchmark AECO price. In the quarter, our realized financial hedging gain of $76 million ($1.17 per Mcf) was $207 million lower than our gain of $283 million ($3.88 per Mcf) for the same period in 2009 as a result of our settled fixed price contract prices of $6.18 per Mcf for the period being approximately $3.00 per Mcf lower than the same period in 2009. For details of the specific pricing on our hedging program, see the notes to our Interim Consolidated Financial statements.

In the first six months the average natural gas price, excluding realized financial hedges, decreased by $0.07 per Mcf when compared to the same period in 2009, which was consistent with the reduction in the benchmark AECO price. Our realized financial gain in 2010 was $110 million ($0.84 per Mcf), a significant decrease from our 2009 gain of $536 million ($3.66 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 June 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

Production volumes for Southern Alberta decreased 11 percent in the second quarter of 2010 compared to the same period in 2009 due to expected natural declines, the cumulative effect of lower drilling and tie-in activity throughout 2009 in response to low commodity prices, and weather related drilling and completion delays in the first half of 2010. The decrease was offset by increased production from our coal bed methane ("CBM") properties and production from wells that were drilled in 2009 and tied-in during 2010.

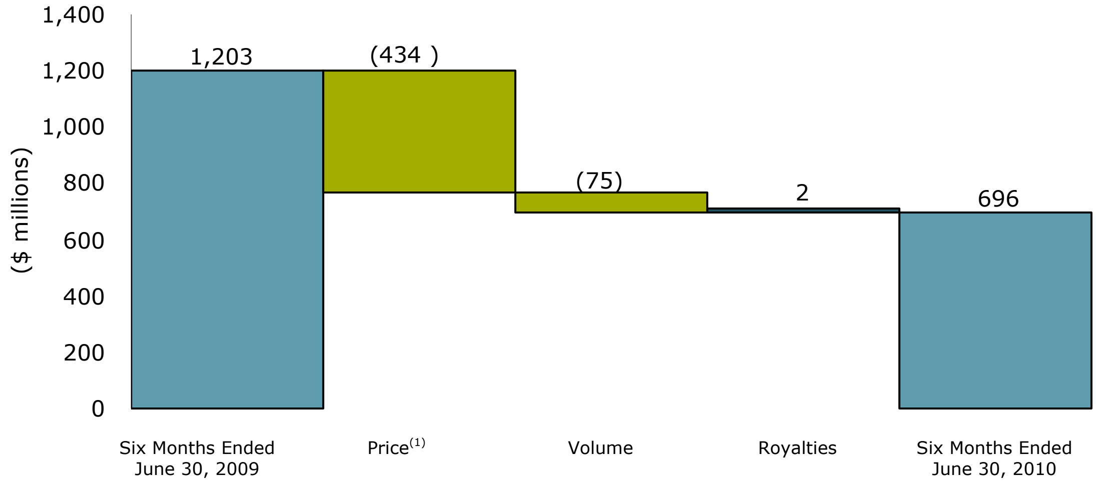
Royalties in the second quarter were consistent with 2009. The effective royalty rate for the second quarter of 2010 was 1.0 percent (2009 – 1.3 percent).

Production and mineral taxes decreased by $8 million in the second quarter compared to 2009 primarily as a result of lower prices and volumes in 2010 and the true up of 2009 estimated amounts in 2010.

Transportation and selling costs in the second quarter were consistent with the same period in 2009.

Operating expenses in the second quarter were consistent with 2009 as higher electricity prices and workover activity were offset by lower salaries and lower repair and maintenance costs.

Six Months Ended June 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

Southern Alberta production volumes decreased 11 percent year over year at June 30, due to expected natural declines, the cumulative impact of lower drilling and tie-in activity throughout 2009 in response to low commodity prices and weather related drilling and completion delays in 2010. The decrease was offset by increases in CBM production and production from wells drilled in 2009 that were tied-in during 2010.

Decreased Royalties for the period were the result of lower volumes. The average royalty rate for the six month period ended June 30, 2010 was 1.5 percent (2009 – 1.6 percent).

Production and mineral taxes in the first six months of 2010 were $7 million lower than 2009 due to lower price and volumes in 2010 and the true up of 2009 estimated amounts in 2010.

Transportation and selling costs for the six months ended June 30, 2010 were consistent with 2009.

Operating expenses for the period decreased four percent to $119 million mainly as a result of a lower level of repair and maintenance activity.

Canadian Plains - Other

Financial Results

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 415**	$ 236	**$ 830**	$ 467
Expenses				
Operating	**7**	6	**12**	11
Purchased product	**402**	228	**806**	446
Operating Cash Flow	**$ 6**	$ 2	**$ 12**	$ 10

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 six month periods ended June 30, 2010 is largely the result of increased volumes for both crude oil and natural gas, and higher crude oil prices. Canadian Plains – Other also includes a small amount of third party processing fee income.

Capital Investment

Canadian Plains capital investment in the second quarter of 2010 was $102 million (2009 - $99 million) and for the six months ended June 30, 2010 was $241 million (2009 - $334 million). The $93 million decrease from year to date 2009 was primarily the result of winter weather, an early spring thaw and continued poor weather conditions throughout the second quarter which resulted in the deferral of some planned investment from the first half of 2010 to later in the year.

The Canadian Plains Division drilled 16 net wells (2009 – 56 net wells) in the second quarter of 2010. For the six months, we drilled 137 net wells (2009 – 430 net wells). Fewer wells were drilled in 2010 as poor weather conditions restricted access to our leases.

For the six months ended June 30, 2010, approximately 81 percent of our capital investment was on our crude oil properties (2009 - 42 percent) and primarily included capital maintenance and polymer injection investment in the Greater Pelican Region, drilling and facility work at Weyburn and drilling in the Lower Shaunavon area of Saskatchewan and Bakken new development projects. Our investment included 54 net oil development wells (2009 - 28 net oil development wells) and six net oil exploration wells, as well as 78 gas development wells (2009 - 402 wells). We also performed 409 well recompletions (2009 - 410 recompletions) which are mostly for CBM. In addition, 33 stratigraphic test wells were drilled in the Grand Rapids project in the Greater Pelican Region (2009 – 18 wells) to further our understanding of the reservoir existing on our leases.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues	**$ (18)**	$ (316)	**$ 199**	$ (227)
Expenses				
Operating	**(3)**	3	**1**	22
Purchased product	**(38)**	(22)	**(62)**	(38)
Depreciation, depletion and amortization	**12**	12	**20**	25
Segment Income (Loss)	**11**	(309)	**240**	(236)

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 June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
General and administrative	**$ 59**	$ 52	**$ 111**	$ 93
Interest, net	**66**	57	**131**	102
Accretion of asset retirement obligation	**18**	12	**40**	23
Foreign exchange (gain) loss, net	**28**	143	**1**	91
(Gain) loss on divestitures	**9**	-	**8**	-
	$ 180	$ 264	**$ 291**	$ 309

Our General and administrative expenses increased $7 million in the second quarter of 2010 compared to the same period of 2009 (year to date – increase of $18 million), primarily 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.

Net interest in the second quarter of 2010 was $66 million, which was $9 million higher than the second quarter of 2009 (year to date – increase of $29 million). Both the second quarter and year to date 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 second quarter includes $4 million (year to date $8 million) of financing cost amortization related to the setup of our debt financing programs. Our weighted average interest rate on outstanding debt at June 30, 2010 was 5.6 percent compared to 5.5 percent at June 30, 2009.

In the second quarter of 2010 we reported a foreign exchange loss of $28 million compared to a loss of $143 million in 2009, the majority of which was unrealized. The weakening of the Canadian dollar during the second quarter of 2010 led to an unrealized loss on our U.S. dollar debt, which was partially offset by an unrealized gain on our U.S. dollar partnership contribution receivable. For the six months ended June 30, 2010 we recognized a foreign exchange loss of $1 million (2009 - loss of $91 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. 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 June 30		**Six Months Ended June 30**	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Revenues				
Crude Oil	**$ 118**	$ (17)	**$ 116**	$ (48)
Natural Gas	**(98)**	(277)	**145**	(141)
	20	(294)	**261**	(189)
Expenses	**(2)**	3	**2**	22
	22	(297)	**259**	(211)
Income Tax Expense (Recovery)	**6**	(83)	**73**	(61)
Unrealized Mark-to-Market Gains (Losses), after-tax	**$ 16**	$ (214)	**$ 186**	$ (150)

DEPRECIATION, DEPLETION and AMORTIZATION

In the second quarter of 2010, DD&A was $325 million (2009 - $382 million) and for the six month period ended June 30, 2010 was $649 million (2009 - $762 million). We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream DD&A in the second quarter of 2010 of $264 million (2009 - $316 million) and year to date of $529 million (2009 - $620 million) were lower primarily as a result of a lower DD&A rate partially offset by increased production volumes. Our Downstream Refining assets DD&A in the second quarter of 2010 was $49 million (2009 - $54 million) and 2010 year to date was $100 million (2009 - $117 million). Decreases to our Downstream DD&A were primarily due to a strengthening of the Canadian dollar average exchange rate.

INCOME TAX

The second quarter income tax expense of $11 million was $59 million lower than the same period in 2009. Current income tax expense in the second quarter of 2010 was $15 million compared to $151 million in the second quarter of 2009, and future tax recovery was $4 million compared to a recovery of $81 million for 2009.

Year to date at June 30, 2010 our income tax expense of $126 million was $18 million lower than the same period in 2009. Current income tax expense for the period was $30 million (2009 - $249 million). Future tax expense for 2010 was $96 million compared to a recovery of $105 million for the period in 2009.

When comparing the 2010 and 2009 second quarter and year to date amounts, 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 second quarter of 2010 was 6.0 percent (year to date - 15.3 percent) compared to 30.4 percent in 2009 (year to date – 17.6 percent). The decreases for the quarter and six months ended are primarily due to two factors: the impact of permanent differences on lower overall earnings before income taxes in the quarter, as well as the recognition of the tax benefit arising from a loss in our U.S. entities in 2010 compared to earnings in 2009.

It should be noted that for second quarter and year to date 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.

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

	Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian dollars)	**2010**	2009	**2010**	2009
Net cash from (used in)				
Operating activities	**$ 471**	$ 793	**$ 1,291**	$ 1,475
Investing activities	**(468)**	(532)	**(840)**	(1,250)
Net cash provided (used) before Financing activities	**3**	261	**451**	225
Financing activities	**16**	(392)	**(187)**	(281)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(7)**	(3)	**(10)**	(5)
Increase (decrease) in cash and cash equivalents	**$ 12**	$ (134)	**$ 254**	$ (61)

OPERATING ACTIVITIES

Net cash from operating activities decreased $322 million in the second quarter compared to 2009 and decreased $184 million in the six months compared to 2009. Cash Flow was $537 million during the second quarter compared to $945 million for the same period in 2009 and $1,258 million for the first six months (2009 - $1,686 million). Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital.

Excluding the impact of risk management assets and liabilities, we had working capital of $708 million at June 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 June 30, 2010 decreased to $468 million from $532 million for the same period in 2009. Year to date net cash used in investing of $840 million was a decrease of $410 million from the same period in 2009. Capital expenditures decreased in the second quarter to $477 million compared to $489 million in 2009 while year to date capital expenditures decreased by $171 million to $970 million compared to 2009. Total divestiture proceeds in 2010 of $144 million include $72 million which occurred in the second quarter. The net change in non-cash working capital decreased cash by $63 million in the second quarter of 2010 (2009 – $59 million) and decreased cash by $16 million in the first six months of 2010 (2009 – $126 million). The decreased capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

We currently have in place an unsecured credit facility in the amount of $2.5 billion or its equivalent amount in U.S. dollars. The revolving syndicated credit facility consists of two tranches, a $2.0 billion 3-year tranche, that expires November 30, 2012, and a $500 million 364-day tranche, that expires November 29, 2010. At June 30, 2010, Cenovus had $2.3 billion in unused credit capacity on this facility. Included in Cenovus's long-term debt obligations of $3,821 million at June 30, 2010, are $165 million in principal obligations related to the issuance of commercial paper. These amounts are fully backstopped by the Company's 3-year tranche of the revolving syndicated credit facility, which has no repayment requirements within the next year. We are currently in compliance with all of our financial covenants under this credit facility.

On May 26, 2010, the Company filed a prospectus to exchange up to US$800 million aggregate principal amount of 4.50 percent Senior Notes due 2014, up to US$1,300 million aggregate principal amount of 5.70 percent Senior Notes due 2019 and up to US$1,400 million aggregate principal amount of 6.75 percent Senior Notes due 2039 registered under the U.S. Securities Act of 1933, as amended, for any and all of its outstanding 4.50 percent notes, 5.70 percent notes and 6.75 percent notes, which were issued on September 18, 2009, in a transaction exempt from registration. The exchange offer was launched on May 28, 2010, was extended on June 28, 2010 and expired on June 30, 2010. All of the 4.50 percent notes and 6.75 percent notes and substantially all of the 5.70 percent notes were exchanged in accordance with the terms of the exchange offer.

On June 24, 2010, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. At June 30, 2010, $1.5 billion of the shelf remains unutilized. The Canadian shelf prospectus expires in July 2012.

On July 7, 2010, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$1.5 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. The shelf prospectus expires in August 2012.

In the first and second quarters of 2010 Cenovus declared and paid a dividend of $0.20 per share. Dividend payments for the first six months of 2010 totaled $300 million. Dividends are at the sole discretion of the Board and considered quarterly.

Net cash generated from financing activities for the second quarter of 2010 was $16 million compared to $392 million used in 2009. For the six months ended June 30, 2010, $187 million of cash was used in financing activities (2009 - $281 million). Our debt, including current portion, was $3,821 million as at June 30, 2010 compared with $3,656 million as at December 31, 2009.

FINANCIAL METRICS

	June 30, 2010	December 31, 2009
Debt to Capitalization	**28%**	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 and foreign exchange gains/losses. 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 June 30, 2010 there were 751.8 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 an average market price or purchased on the market at prevailing market rates. For the period ended June 30, 2010, no common shares were issued from Treasury to meet our DRIP requirements. Further information can be found in the notes to the Interim Consolidated Financial Statements.

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.

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.

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 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 identifying and managing these issues.

For a description of risk factors that may affect our performance, see the Advisory section at the end of this document.

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 United States and Canada. These include proposed federal legislation and state actions in the United States 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 legislation 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 these 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 operating in a responsible manner and we recognize the importance of reporting to stakeholders in a transparent and accountable way. 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, updates to the CR section of our website were made. As part of these updates we have included the "Corporate Responsibility 2009 Performance Measures" which provides information on our CR performance in 2009 on a number of measures.

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.

We are committed to integrating the principles of corporate responsibility into the way we conduct our business across all of our operations and we recognize the importance of reporting to stakeholders in a transparent and accountable way.

ALBERTA'S ROYALTY/REGULATORY FRAMEWORK

On March 11, 2010, the Alberta government outlined changes to the Alberta royalty structure which included:

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

On May 27, 2010, the Alberta Government released further updates to the royalty structure. The update was primarily focused on supporting deep basin gas drilling and improving the economics of unconventional gas plays, as well as horizontal oil and gas drilling. The changes detailed in this release will be effective January 1, 2011, for all wells drilled, excluding oil sands, after May 1, 2010. Impacts of the release include:

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

Updates to the royalty curves for conventional oil and natural gas were included in the May 2010 release. The effective date of the new curves is January 1, 2011.

For Cenovus, the main impact of the royalty changes will 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.

The Government of Alberta has also formed the "Task Force on Regulatory Enhancement" with a mandate to perform a comprehensive review of Alberta's regulatory system for resource development. By working with the oil and gas industry and other stakeholders, the task force has been asked to look for efficiencies and ensure Alberta's competitive balance while maintaining environmental conservation and stewardship. A progress report was released in the second quarter of 2010 with the final report expected before the end of this year.

ACCOUNTING POLICIES AND ESTIMATES

Basis of Presentation

Our results for the six month period from January 1 to June 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 June 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 June 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.

The IFRS accounting policies that we expect to use have not changed from those described in our MD&A for the three months ended March 31, 2010 and the year ended December 31, 2009. We are continuing to monitor any new or amended IFRSs 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.

Implementation of the process and system changes required for IFRS have been completed, and are currently being used to prepare and record our draft IFRS transactions and balances.

We are currently working on a draft of our IFRS opening balance sheet, and expect to begin drafting our 2010 quarterly IFRS financial results in the third quarter of 2010. We have also started drafting our IFRS financial statements for the three month period ending March 31, 2011 as well as for the year ending December 31, 2011.

We have completed updating our internal controls documentation related to the IFRS opening balance sheet and we are currently updating our 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.

In terms of financial literacy, we began formal IFRS education sessions across Cenovus during the second quarter of 2010. The education sessions include an overview to IFRS which is being presented to a broad range of employees across the company. Other sessions include a detailed IFRS accounting policies and work practices session which is focused on employees in the finance and financial reporting areas of the company. 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 finalize our IFRS opening balance sheet and 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 working interest of 100 percent in many of these projects;
- Continue the development of our resources in multiple phases using a manufacturing like approach to benefit from repeatable and scalable processes and low costs;
- Leadership in low-cost oil sands development; enabled by technology 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 hedging execution; and
- Maintain a meaningful dividend.

We believe 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 for the foreseeable future. Offsetting this is a relatively weak price outlook for natural gas and refining margins. The key hurdles that need to be effectively managed to enable our growth are commodity price volatility, environmental regulations, government project approvals 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 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 $144 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 Grand Rapids, Telephone Lake and Narrows Lake in order to achieve this.

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.

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.

Our forward-looking information respecting anticipated 2010 cash flow, operating cash flow and pre-tax cash flow is based on the following assumptions: achieving average 2010 production of approximately 120,200 bbls/d to 129,700 bbls/d of crude oil and liquids and 740 MMcf/d to 760 MMcf/d of natural gas; average commodity prices for 2010 of a WTI price of US$65 per bbl to US$85 per bbl and a WCS price of US$54 per bbl to US$71 per bbl for oil, a NYMEX price of US$5.50 per Mcf to US$6.15 per Mcf and AECO price of $5.15 per GJ to $5.70 per GJ for natural gas; an average U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 US$/CDN$; and an average Chicago 3-2-1 crack spread for 2010 of US$7.50 per bbl to US$9.50 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 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 in our Annual Information Form/Form 40-F 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.

OIL AND GAS INFORMATION

Our disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to us by Canadian securities regulatory authorities that permits us to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by us may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 ("NI 51-101"). The reserves quantities disclosed represent net proved and probable reserves calculated using the standards contained in Regulation S-X of the U.S. Securities & Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2009.

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.

CURRENCY

All information included in this document and the Interim Consolidated Financial Statements and comparative information is shown on a Canadian dollar, before royalties basis unless otherwise noted.

ABBREVIATIONS

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

Oil and Natural Gas Liquids	
bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
NGLs	natural gas liquids
BOE	barrel of oil equivalent

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet
MMbtu	million British thermal units
GJ	gigajoule

NON-GAAP MEASURES

Certain measures in this document do not have any 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.

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.