Third Quarter
2010

Cenovus increases third quarter oil sands production by 25%
Company's expansion plans on track

- Production from the Foster Creek and Christina Lake oil sands projects increased 25% in the third quarter of 2010 compared with the same period in 2009.
- The Christina Lake phase C expansion is approximately 80% complete and on schedule.
- Foster Creek F, G and H expansions received regulatory approval, marking a milestone in Cenovus's plan to achieve oil sands production of 300,000 barrels per day (bbls/d) in 2019.
- Cash flow remained strong at $509 million for the quarter.
- Established oil and natural gas properties generated about $340 million of operating cash flow in excess of capital expenditures in the third quarter of 2010, providing cash to fund the company's oil sands growth.
- The company sold $159 million of non-core assets as part of its divestiture program.
- The company's financial position strengthened further in the quarter, with a debt to capitalization ratio of 26% and a renegotiated bank facility.
- Corporate guidance was updated to reflect nine-month actual results and the company's expectations for the fourth quarter.

"The company delivered strong upstream performance in the quarter, which was partially offset by weaker refining results," said Brian Ferguson, President & Chief Executive Officer of Cenovus. "We continue to make good progress on the construction of expansion phases at Christina Lake and received regulatory approval to add three new phases at Foster Creek. These are significant milestones in our plan to achieve a five-fold increase in oil sands production by the end of 2019. The coker and refinery expansion project at our jointly owned Wood River Refinery also advanced and is now 87% complete.''

Financial & Production Summary[1]

(for the period ended September 30) ($ millions, except per share amounts)	**2010 Q3**	2009 Q3	% change	2010 9 months	2009 9 months	% change
Cash flow[2] Per share diluted	**509** **0.68**	924 1.23	-45	1,767 2.35	2,610 3.48	-32
Operating earnings[2] Per share diluted	**159** **0.21**	427 0.57	-63	654 0.87	1,353 1.80	-52
Capital investment	**480**	515	-7	1,403	1,655	-15
Production (before royalties)						
Foster Creek (bbls/d)	**50,269**	40,367	25	50,798	34,593	47
Christina Lake (bbls/d)	**7,838**	6,305	24	7,660	6,489	18
Foster Creek & Christina Lake Total (bbls/d)	**58,107**	46,672	25	58,458	41,082	42
Other Oil and NGLs (bbls/d)	**69,960**	79,815	-12	70,594	78,235	-10
Natural gas (MMcf/d)	**738**	830	-11	754	851	-11

[1] Effective Jan. 1, 2010, Cenovus changed its reporting currency to Canadian dollars and started presenting production volumes on a before royalties basis.
[2] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.

Calgary, Alberta (October 28, 2010) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered strong production growth from its oil sands assets with a 25% increase at Foster Creek and Christina Lake in the third quarter of 2010 compared with the same period last year. Expansions helped boost net oil production from the two facilities to 58,000 bbls/d from 47,000 bbls/d in the third quarter of 2009. Foster Creek achieved a new daily record for gross production of 119,000 bbls/d in the third quarter, approaching the design capacity of the facility.

"The company's upstream operating and financial performance is meeting or exceeding expectations, driven by higher than anticipated production at our oil sands operations and lower than projected operating and capital expenditures,'' Ferguson said.

Cenovus continues to add production capacity at both Christina Lake and Foster Creek. Construction is progressing as planned on Christina Lake phases C and D, which will each add 40,000 bbls/d of gross production capacity. Christina Lake phase C is approximately 80% complete, on budget and on schedule for first production in the third quarter of 2011. Site preparation is underway for phase D and module fabrication continues at Cenovus's assembly yard in Nisku, Alberta, with the first modules for phase D shipped to Christina Lake in mid-October. The regulatory process is ongoing for Christina Lake phases E, F and G with approval anticipated in 2011. In September, Cenovus received regulatory approval for phases F, G and H at Foster Creek, which are expected to increase gross production capacity by 90,000 bbls/d to 210,000 bbls/d. Site preparation is underway for the first of these expansions with initial production for phase F scheduled in 2014.

"We have regulatory approvals in place and construction in progress for 170,000 barrels per day of gross oil sands production capacity in addition to current production,'' Ferguson said. "The company has a strong balance sheet to support the development of these lands as well as additional holdings. We're off to a solid start on the road we've mapped out toward doubling our net asset value within the next five years and increasing total shareholder returns.''

Overall cash flow for the third quarter of 2010 was $509 million, $415 million lower compared with the same period last year, a 45% decrease. This was largely due to weaker realized natural gas prices, which were 37% less than the third quarter of 2009, when the company's hedges were priced significantly higher. Cenovus has chosen to restrict capital investment in natural gas in favour of increasing investment in oil projects. As a result, natural gas production has declined by 11%. The company also paid higher royalties on its Foster Creek production after the project reached royalty payout earlier this year.

Downstream operations in the third quarter of 2010 fell short of the company's expectations. Operating cash flow from the refineries was a deficiency of $32 million, which is $127 million lower than the third quarter of 2009. The decrease was mainly due to higher per unit crude oil costs and lower utilization as a result of a power outage at the Wood River Refinery and a longer than expected turnaround at the Borger Refinery. The company expects its refining results in the fourth quarter to benefit from lower-priced Canadian crude purchased in the third quarter. Despite recent cyclical weakness in the refining industry, the company expects substantial improvements in profitability when the refinery expansion at its Wood River facility comes on stream in the fourth quarter of 2011.

The company has updated its guidance for the balance of this year to reflect actual production and commodity prices for the first nine months of 2010 and new assumptions for the fourth quarter. The updated guidance is available at www.cenovus.com.

Organizational changes support strategic business plan
Cenovus is making changes to its organizational structure to help the company deliver on its 10-year strategic business plan. The changes include the elimination of the divisional format in favour of a consolidated business structure. The members of the executive team remain the same although some roles have changed. John Brannan will take on the new position of Executive Vice-President & Chief Operating Officer with responsibility for all of Cenovus's operations. Harbir Chhina will become Executive Vice-President, Oil Sands, and focus on the operation and development of Cenovus's properties in northern Alberta including the Foster Creek Region, the Christina Lake Region and the Greater Pelican Region. He will also lead the Research & Development/Technology and New Resource Plays & New Ventures teams. The restructuring places a greater focus on the company's marketing and downstream operations at the executive level with Don Swystun moving to the role of Executive Vice-President, Refining, Marketing, Transportation & Development. Harbir and Don and other operations leaders will report directly to John. The changes will take effect December 1, 2010.

"This shift in the way the company is organized is designed to support the growth plan we have in place for the coming decade," Ferguson said. "When we launched Cenovus, we chose to maintain the existing divisional structure to ensure consistent operational performance and minimize risk. As we approach the one-year anniversary of the company, we are now ready to take this important step to help us increase efficiency and place us in an even better position to succeed."

Recognition for leadership in emissions reporting and sustainability
The company received recognition for its leadership in the reporting of greenhouse gas (GHG) emissions by being included in the 2010 Carbon Disclosure Leadership Index for Canada. Cenovus was one of 15 Canadian companies recognized by the Carbon Disclosure Project for its exceptional levels of climate change disclosure. The Carbon Disclosure Project is organized by a coalition of global institutional investors and operates the world's largest storehouse of data on corporate GHG emissions.

Cenovus was added to the 2010 Dow Jones Sustainability Index (DJSI) North America during the third quarter. The DJSI recognizes the leading companies in terms of sustainability from Canada and the United States, with selection being based on an annual assessment of their economic, social and environmental performance.

IMPORTANT NOTE: Effective Jan. 1, 2010, Cenovus changed its reporting currency to Canadian dollars and started presenting production volumes on a before royalties basis to better reflect its business and to enhance comparability to its peers. All numbers are net to Cenovus unless otherwise stated. See the Advisory for a description of the non-GAAP measures and oil and gas definitions used in this quarterly report. Cenovus has posted its Interim Consolidated Financial Statements to www.cenovus.com.

Oil Sands Operations

(Before royalties) (Mbbls/d)	Daily Production									
	2010				2009					2008
	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Foster Creek	**51**	**50**	51	51	38	47	40	35	29	26
Christina Lake	**8**	**8**	8	7	7	7	6	7	7	4
Total[1]	**58**	**58**	59	59	44	54	47	41	35	30

[1] Totals may not add due to rounding.

Foster Creek and Christina Lake

Cenovus's oil sands properties in northern Alberta represent the company's most significant opportunity for substantial near term growth. Cenovus's producing oil sands projects, Foster Creek and Christina Lake, use specialized methods, such as steam-assisted gravity drainage (SAGD), to drill and pump the oil to the surface. The projects are operated by Cenovus and jointly owned with ConocoPhillips. Cenovus continues to advance technologies in its oil sands operations that reduce the amount of water, natural gas and electricity used and minimize land disturbance.

Production

- Quarterly production at both Foster Creek and Christina Lake slightly exceeded the company's original guidance.
- Foster Creek produced more than 50,000 bbls/d (net) in the third quarter of 2010, up from about 40,000 bbls/d (net) during the same period last year, a 25% increase. This is mainly due to increased production from the phase D and E expansions, combined with plant and well optimizations and increased output from wedge wells.
- Third quarter production at Foster Creek was slightly lower than the second quarter because of two external power outages and a water-handling system disruption. Foster Creek began a planned turnaround near the end of the third quarter, which reduced production by approximately 17% for three weeks. The plant returned to full production capacity on October 18 and remains on track to meet production guidance.
- About 13% of current production at Foster Creek comes from wedge wells. The individual horizontal wells are drilled between existing SAGD well pairs, reaching oil that would otherwise be unrecoverable. Wedge wells have the potential to increase overall recovery from the reservoir by about 10%, while at the same time reducing the steam to oil ratio (SOR). The company plans to drill four new wedge wells at Foster Creek by the end of the year, in addition to the 47 drilled to date, 30 of which are producing. One wedge well is producing at Christina Lake, with three more expected to commence drilling by the end of the year.
- Production at Christina Lake increased by 24% to about 7,800 bbls/d (net) in the third quarter compared with the same period in 2009. This was mainly due to increased production from the phase B expansion, well optimizations and production from the first wedge well.

Expansions

- In the third quarter of 2010, the company received regulatory approval from the Alberta Energy Resources Conservation Board (ERCB) for the Foster Creek expansion phases F, G and H. When these phases are completed, they are expected to increase Foster Creek's gross production capacity to 210,000 bbls/d from the current 120,000 bbls/d. The next step for the expansion project is to receive final partner approvals.
- Engineering and preliminary ground work on phase F at Foster Creek is underway, with first production expected in 2014. The other two phases are expected to start producing in 2016 and 2017, respectively.

Costs

- Operating costs at Foster Creek and Christina Lake were better than the company's original guidance, averaging $11.20/bbl in the third quarter of 2010, a 2% reduction from $11.47/bbl in the third quarter of 2009. This was mainly due to increased production, offset by higher repair, maintenance and workover expenses, increased fuel costs and higher staffing levels.

- Fuel expenses are the company's most significant operating cost at Foster Creek and Christina Lake. Removing that element, non-fuel operating costs were better than the company anticipated at $9.25/bbl in the third quarter of 2010 compared with $10.00/bbl in the third quarter of 2009, an 8% decrease.
- As a result of the Foster Creek project reaching payout for royalty purposes in February, its average royalty rate was about 18% in the third quarter of 2010 compared with 3% in the third quarter of 2009, an increase of $34 million.
- Cenovus continues to achieve some of the best SORs in the industry with a ratio of approximately 2.0 at Christina Lake and 2.3 at Foster Creek for a combined SOR of 2.3 in the third quarter. This means 2.3 barrels of steam are needed for every barrel of oil produced. A lower SOR means less natural gas is used to create the steam, which results in fewer emissions, lower water usage and reduced operating costs.

Future Projects

- A regulatory application for the Narrows Lake project, jointly owned with ConocoPhillips, is now with the ERCB and Alberta Environment. The application is the first to include the option of using a combination of SAGD and solvent aided process (SAP) for oil production. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d. The target date for first production is 2016. In preparation for regulatory approval, 35 stratigraphic test wells have been drilled at Narrows Lake to date in 2010.
- Drilling of a single SAGD well pair and installation of the pilot facility is nearing completion at Grand Rapids in the Greater Pelican Region. Grand Rapids is a 100% Cenovus-owned project that has the potential to add production capacity of up to 180,000 bbls/d upon completion. Cenovus is anticipating approval from Alberta Environment within the next month for the Grand Rapids pilot, which falls under the company's existing Pelican Lake operating license. Early results from the Grand Rapids pilot are expected in the first half of 2011. The first commercial phase of the project, with capacity of 60,000 bbls/d, could be in production by 2017.
- Additional information about the geology of the reservoir is being collected to support the regulatory application that was previously filed for the Telephone Lake project in the Borealis Region. Cenovus drilled 26 stratigraphic test wells and 16 additional groundwater monitoring wells in the first nine months of 2010 at Telephone Lake to better assess the characteristics and quality of the resource.

Conventional Oil, Natural Gas Liquids (NGLs) and Natural Gas

(Before royalties)	Daily Production[1]									
	2010				2009					2008
	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Conventional Oil & NGLs (Mbbls/d)	**71**	**70**	70	72	77	75	80	76	79	82
Natural Gas (MMcf/d)	**754**	**738**	751	775	837	797	830	856	866	954

[1] Reflects production from the sale of non-core assets in the fourth quarter of 2009, and the second quarter of 2010.

Cenovus has a large base of conventional oil and natural gas properties across Alberta and Saskatchewan. The oil operations include Pelican Lake (Wabiskaw formation) and Weyburn as well as production in southern Alberta and Saskatchewan. Cenovus's natural gas properties in Alberta are established, reliable fields with efficient operations. These established assets are an important component of the company's financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as a hedge against price fluctuations, because natural gas fuels the company's oil sands and refining operations.

- Conventional oil and NGLs production was about 70,000 bbls/d in the third quarter of 2010, or a 12% decrease compared with the same period last year. This was primarily the result of expected natural declines, dispositions of non-core properties, as well as temporary pipeline constraints. The declines were partially offset by better than anticipated results from the company's polymer flood at Pelican Lake, well optimization efforts at Weyburn as well as new production in the Lower Shaunavon and southern Alberta areas.
- The Lower Shaunavon oil asset in Saskatchewan is an early stage development opportunity for Cenovus. Production averaged about 585 bbls/d from 12 wells during the third quarter. The company has drilled an additional six wells in this area and continues to actively drill.
- The company has almost 225 prospective sections in the Bakken region of southern Saskatchewan. Development is in the early stages and Cenovus is analyzing the results of the initial appraisal wells drilled. Work on both the Shaunavon and Bakken assets in the third quarter was delayed by wet weather.
- Operating costs for Cenovus's conventional oil and liquids operations increased 42% to $12.11/bbl in the third quarter of 2010 compared with the same period last year, in line with the company's original guidance. This was mainly due to increased workover, repair and maintenance activity as well as lower production volumes. There was also increased chemical usage at Pelican Lake as more wells were switched to polymer injection, which is expected to lead to increased oil recovery over time. In response to low commodity prices in 2009, some workover and maintenance projects were deferred to this year.
- Natural gas production was 738 million cubic feet per day (MMcf/d), an 11% decrease in the third quarter of 2010 compared with the same period in 2009. This was due to the company shifting capital from natural gas to crude oil development in response to low natural gas prices.
- Cenovus plans to manage declines in natural gas production, targeting a long term production level of between 400 and 500 MMcf/d to match Cenovus's future anticipated internal usage at its oil sands and refining facilities.
- A pilot project began during the quarter at Pelican Lake to test the use of compressed natural gas to fuel company pickup trucks. The natural gas is produced at the site and a filling station was installed and is now operating.

Downstream

Cenovus's downstream operations include the Wood River Refinery in Illinois and the Borger Refinery in Texas, which are jointly owned with the operator, ConocoPhillips. The Borger Refinery has gross coking capacity of 25,000 bbls/d. The coker and refinery expansion (CORE) project at Wood River is adding 65,000 bbls/d gross coking capacity, bringing the total at Wood River to 83,000 bbls/d. With completion of the CORE project, Cenovus's Wood River Refinery will have an increased ability to process a variety of crude oil feedstocks and produce a larger percentage of high value clean products. It is anticipated operating cash flow at Wood River will improve by about US$200 million a year net to Cenovus once the project is completed. The company's two refineries will then have a combined capacity to process as much as 275,000 bbls/d of heavy crude oil.

- In the third quarter of 2010, the two refineries produced 409,000 bbls/d of refined products, down about 9% compared with the third quarter of 2009.

- Operating cash flow for downstream operations in the third quarter of 2010 did not meet the company's expectations. There was a deficiency of $32 million, down from a surplus of $95 million in the third quarter of 2009, mainly due to higher per unit crude oil costs and reduced utilization. The company has updated its guidance for the remainder of the year.
- Refinery crude utilization averaged 89% or 401,000 bbls/d of crude throughput, about 6% lower than in the same period a year ago, due to an extended turnaround at Borger, a power outage at Wood River and unplanned maintenance.
- The CORE project was about 87% complete at the end of the third quarter. Commissioning of several of the process units has been completed with an anticipated coker startup in the fall of 2011, when the company expects that CORE project expenditures will have reached US$3.7 billion (US$1.85 billion for Cenovus).

Financial

Dividend

The Cenovus Board of Directors declared a fourth quarter dividend of $0.20 per share, payable on December 31, 2010, to common shareholders of record as of December 15, 2010. Based on the October 27, 2010 closing share price on the Toronto Stock Exchange of $29.09, this represents an annualized yield of about 2.8%. Declaration of dividends is at the sole discretion of the Board. Earlier this year, the Board approved a dividend reinvestment plan, which was made available to shareholders for the second quarter 2010 dividend. More information is available at www.cenovus.com.

Hedging Strategy

The natural gas and crude oil hedging strategy helps Cenovus to achieve more predictability around cash flow and safeguard its capital program. The strategy is to hedge up to 75% of the next year's expected natural gas production, net of internal fuel use, and up to 50% and 25%, respectively, in the following two years. The company has approval for fixed price hedges on as much as 50% of net liquids production in the next year and on 25% of net liquids production for each of the following two years.

In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 100 MMcf/d of natural gas is consumed at the company's SAGD and refinery operations, which is offset by the gas Cenovus produces. This natural hedge is considered when determining the company's financial hedging limits.

Cenovus's hedging position at September 30, 2010, comprises:

- 412 MMcf/d of natural gas hedged for the fourth quarter of this year, or approximately 70% of the quarter's expected gas production, net of internal use, at an average NYMEX price of US$6.28/Mcf
- 29,100 bbls/d of crude oil hedged for the fourth quarter of this year, or approximately 23% of the quarter's anticipated oil production, at an average WTI price of US$78.91/bbl and an additional 5,000 bbls/d, or approximately 4% of the quarter's expected oil production, at an average WTI price of C$89.65/bbl
- 22,000 bbls/d of 2011 oil production hedged at an average WTI price of US$85.42/bbl and an additional 23,000 bbls/d hedged at an average WTI price of C$88.36/bbl
- 351 MMcf/d of natural gas hedged for 2011 at an average NYMEX price of US$5.82/Mcf
- 130 MMcf/d of natural gas hedged for 2012 at an average NYMEX price of US$5.96/Mcf

Cenovus's realized after-tax hedging gains for the third quarter of 2010 were $61 million, down from $238 million in the third quarter of 2009, when natural gas hedging prices were significantly higher.

Financial Highlights

- Cash flow for the third quarter of 2010 was $509 million, down 45% from the same period in 2009, largely due to lower realized natural gas prices, managed declines in gas production and lower cash flow from Cenovus's U.S. refining joint venture.
- Capital investment during the quarter was $480 million, a decrease of 7% compared with the third quarter of 2009, primarily due to the CORE project at the Wood River Refinery nearing completion, partially offset by increased investment in conventional oil properties as well as the Christina Lake expansion.
- Free cash flow was $29 million for the third quarter of 2010, $380 million lower than in the third quarter of 2009.
- Cenovus targets a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At September 30, 2010, the company's debt to capitalization ratio was 26% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.2 times.
- Operating earnings were $159 million, or 21 cents per share, down 63% from the same period a year ago, for reasons similar to those outlined for cash flow. Cenovus's management views operating earnings as a better measure of performance than net earnings because unrealized gains and losses are removed from operating earnings.
- Cenovus's net earnings in the third quarter were $223 million, more than double the same quarter in 2009. Net earnings were positively impacted by an unrealized mark-to-market after-tax gain of $45 million, compared with an after-tax loss of $252 million in the third quarter of 2009, and an unrealized after-tax foreign exchange gain of $19 million, compared with an after-tax loss of $74 million in the third quarter of last year, offset by lower cash flow.
- Cenovus received an average realized price, including hedging, of $61.88/bbl for its oil, compared with about $64.00/bbl during the third quarter of last year. The average realized price, including hedging, for natural gas was $4.77/Mcf, 37% less than the third quarter of 2009, which included substantial hedging gains.
- In September, Cenovus renegotiated its $2.5 billion revolving syndicated credit facility, combining two existing tranches into a single tranche with a four-year term, and a maturity date of November 30, 2014. As of September 30, the company had utilized $22 million of the facility, leaving nearly the full amount available for use.
- Cenovus sold certain non-core assets in southeastern Alberta and southwestern Saskatchewan for net proceeds of $159 million at the end of the third quarter. The year-to-date divestiture total now stands at $312 million. The company continues to assess its portfolio and may consider selling other non-core assets if market conditions are favourable. The company has been able to sell non-core assets despite a challenging divestiture market.
- Cenovus is on track with its implementation plan to convert its accounting policies to International Financial Reporting Standards (IFRS) for the first quarter of 2011.

Earnings Reconciliation Summary						
(for the period ended September 30) ($ millions, except per share amounts)	**2010 Q3**	2009 Q3		**9 months 2010**	9 months 2009	
Net earnings Add back (losses) & deduct gains:	**223**	101		**920**	776	
Unrealized mark-to-market hedging gain (loss), after-tax	**45**	-252		**231**	-402	
Non-operating foreign exchange gain (loss), after-tax	**19**	-74		**35**	-175	
Operating earnings[1]	**159**	427		**654**	1,353	
Per share diluted	**0.21**	0.57		**0.87**	1.80	

[1]Operating earnings is a non-GAAP measure as defined in the Advisory.

ADVISORY

NON-GAAP MEASURES

This quarterly report contains references to non-GAAP measures as follows:

- Operating cash flow is defined as net revenues, less production and mineral taxes, transportation and selling, operating and purchased product expenses and is used to provide a consistent measure of the cash generating performance of the company's assets and improves the comparability of Cenovus's underlying financial performance between periods.
- Cash flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital from continuing operations, both of which are defined on the Consolidated Statement of Cash Flows, in Cenovus's interim consolidated financial statements.
- Operating earnings show net earnings excluding non-operating items such as the after-tax impacts of a gain/loss on discontinuance, the after-tax gain/loss of unrealized mark-to-market accounting for derivative instruments, the after-tax gain/loss on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, the after-tax foreign exchange gain/loss on settlement of intercompany transactions, future income tax on foreign exchange related to U.S. dollar intercompany debt recognized for tax purposes only and the effect of changes in statutory income tax rates. Management views operating earnings as a better measure of performance than net earnings because the excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Free cash flow is defined as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.
- Debt to capitalization and debt to adjusted EBITDA are two ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. Debt is defined as the current and long term portions of long term debt. Capitalization is a measure defined as debt plus shareholders' equity. Adjusted EBITDA is defined as net earnings before net interest, income taxes, depreciation, depletion and amortization, accretion of asset retirement obligation, foreign exchange gains or losses, gains or losses on disposal of assets and other income and loss.

These measures have been described and presented in this quarterly report in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. For further information, refer to Cenovus's most recent Management's Discussion and Analysis (MD&A) available at www.cenovus.com.

FORWARD-LOOKING INFORMATION

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

Forward-looking statements involve a number of assumptions, risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The risk factors and uncertainties that could cause actual results to differ materially, and the factors or assumptions on which the forward-looking information is based, include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions inherent in our current guidance; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the effect of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; success of hedging strategies; maintaining a desirable debt to cash flow ratio; accuracy of our reserves, resources and future production estimates; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate the North American integrated heavy oil business and to obtain necessary regulatory approvals; the successful and timely implementation of capital projects; reliability of our assets; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and its application to our business; our ability to generate sufficient cash flow from operations to meet our current and future obligations; our ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta’s regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or the interpretations of such laws or regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on us, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we operate; risks associated with existing and potential future lawsuits and regulatory actions made against us; our financing plans and initiatives; the expected impacts of the plan of arrangement with Encana Corporation ("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 Corporation 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 on pages 73 to 80 of our 2009 Annual Information Form/Form 40-F and in our annual and interim MD&A 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.

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.

Cenovus Energy Inc.
Cenovus Energy Inc. is a Canadian, integrated oil company. It is committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. Operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface, and established natural gas and oil production in Alberta and Saskatchewan. The company also has 50% ownership in two U.S. refineries. Cenovus shares trade under the symbol CVE, and are listed on the Toronto and New York stock exchanges. Its enterprise value is approximately $25 billion. For more information, visit www.cenovus.com.

Management's Discussion and Analysis

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

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

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

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

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

Cenovus is a Canadian oil company headquartered in Calgary, Alberta, with a market capitalization of approximately $22 billion on September 30, 2010. In the third quarter of 2010, we had production of 251,067 boe/d. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. In southern Saskatchewan, we inject carbon dioxide ("CO_2") to enhance oil recovery at our Weyburn operation. We also have established crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have a 50 percent ownership in two refineries in Illinois and Texas, U.S.A., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel to reduce volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase production predominantly from our oil sands projects at Foster Creek and Christina Lake and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach and our established crude oil and natural gas production base is expected to generate reliable production and cash flows which will enable further development of our oil sands assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to continuous innovation. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to minimize surface land disturbance.

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

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

130,000 bbls/d in three phases, with the first phase expected to add production capacity of approximately 40,000 bbls/d.

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

We have a 100 percent working interest in the Telephone Lake property, in the Greater Borealis Region. A joint application and EIA has been submitted to the ERCB and Alberta Environment for the development of the property, including the construction of a facility with production capacity of 35,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands, most of which is undeveloped. In April and June, we issued news releases that highlight detailed information related to our bitumen economic contingent resources and bitumen initially-in-place, enabling investors to more fully understand our inventory of oil sands assets. We also provided further information about our resources and development plans at our Investor Day presentations in June 2010. Our 10 year business plan is to grow our net oil sands production to 300,000 bbls/d by the end of 2019. Growth is expected to be internally funded through cash flow generated from our established crude oil and natural gas production base where we also have opportunities to add production through new technologies. Our natural gas production provides a natural economic hedge for the natural gas required as a fuel source at both our upstream and downstream operations. Our refineries, which are operated by ConocoPhillips, an unrelated United States ("U.S.") public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned 2011 coker startup of the Wood River Coker and Refinery Expansion ("CORE") project. We also employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we will continue to pay meaningful dividends, currently $0.20 per share per quarter, to deliver strong total shareholder return over the long term.

OUR BUSINESS STRUCTURE

Our operations are organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other oil sands interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major oil sands projects: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.
- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major oil properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

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

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

OVERVIEW OF THE THIRD QUARTER 2010

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

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

The commodity price hedging activity continues to be an important element of our business model. This activity reflects our objective of locking in prices on a portion of our natural gas and crude oil production such that we protect a significant portion of the subsequent years' cash flows.

Realized after-tax hedging gains of $61 million during the quarter (year to date - $143 million) reflect the benefits of locking in commodity prices in excess of the current period benchmark prices. These realized hedging gains are significantly less than those of 2009 since they reflect natural gas hedges put in place for 2010 at approximately $6.00 per Mcf as compared to hedges for 2009 put in place at approximately $9.00 per Mcf back in 2008. For more information on our realized hedging prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

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

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

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

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

Unusual weather patterns across our operating areas throughout the year, including a very wet summer, restricted access and as a result our upstream capital investment program is lower than originally planned in some of our operating areas. Although upstream capital spending is lower than expected, production levels have remained at expected levels.

OUR BUSINESS ENVIRONMENT

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

Selected Average Benchmark Prices (1)

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

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. For our realized sales prices, refer to the Operating Netbacks in the Results of Operations section of this MD&A.

(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

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

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

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

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

Benchmark crack spreads for the third quarter of 2010 were better than 2009 due to an increase in consumer demand for refined products partly due to the improved economy in the U.S., resulting in increased gasoline and distillate consumption during the summer driving season in North America.

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

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

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

FINANCIAL INFORMATION

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

SELECTED CONSOLIDATED FINANCIAL RESULTS

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

(1) Non-GAAP measure defined within this MD&A.

(2) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the terms of the plan of arrangement ("the Arrangement"), wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.

(3) We declared and paid a dividend of $0.20 per share in each of the first three quarters of 2010 and US$0.20 per share in the fourth quarter of 2009. The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

NET REVENUES VARIANCE

(millions of dollars)		Three Months Ended	Nine Months Ended
Net Revenues for the Periods Ended September 30, 2009		$ 3,001	$ 8,512
Increase (decrease) due to:			
Upstream Canada	Prices	26	374
	Realized hedging	(250)	(793)
	Volume	(49)	12
	Royalties	(28)	(166)
	Other [1]	168	741
Downstream Refining		(182)	266
Corporate and Eliminations	Unrealized hedging	415	865
	Other	14	(10)
Net Revenues for the Periods Ended September 30, 2010		**$ 3,115**	**$ 9,801**

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

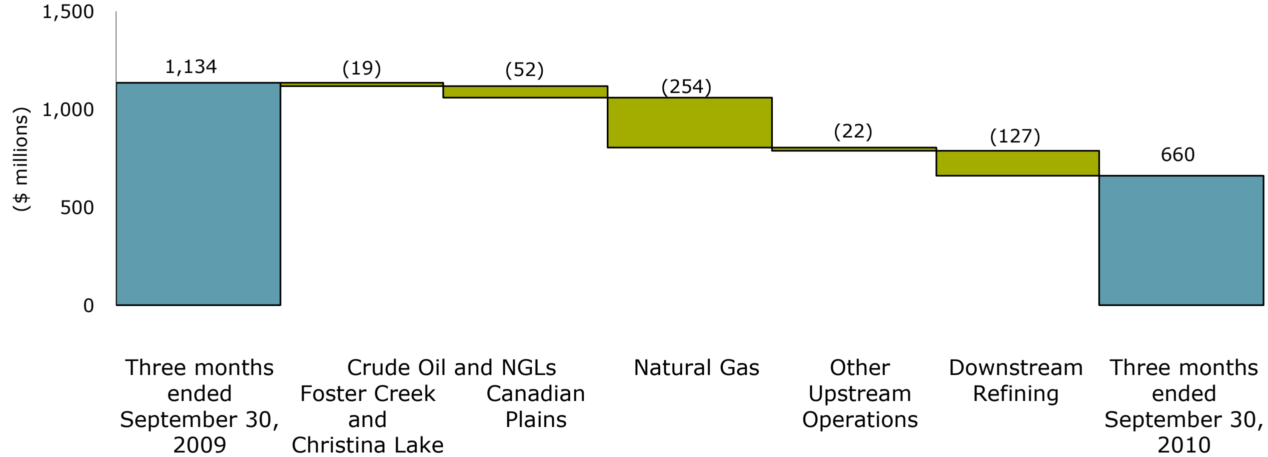
Our Upstream Canada Net Revenues increased in the third quarter of 2010 and the nine months ended September 30, 2010, primarily because of higher crude oil production volumes partially offset by lower volumes and realized prices for natural gas and higher royalties. Year to date Net Revenues also increased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

OPERATING CASH FLOW

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

Operating Cash Flow is a non-GAAP measure defined as Net Revenues less production and mineral taxes, transportation and selling, operating and purchased product expenses. It is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods. Operating Cash Flow excludes unrealized hedging gains and losses which are included in the Corporate and Eliminations segment.

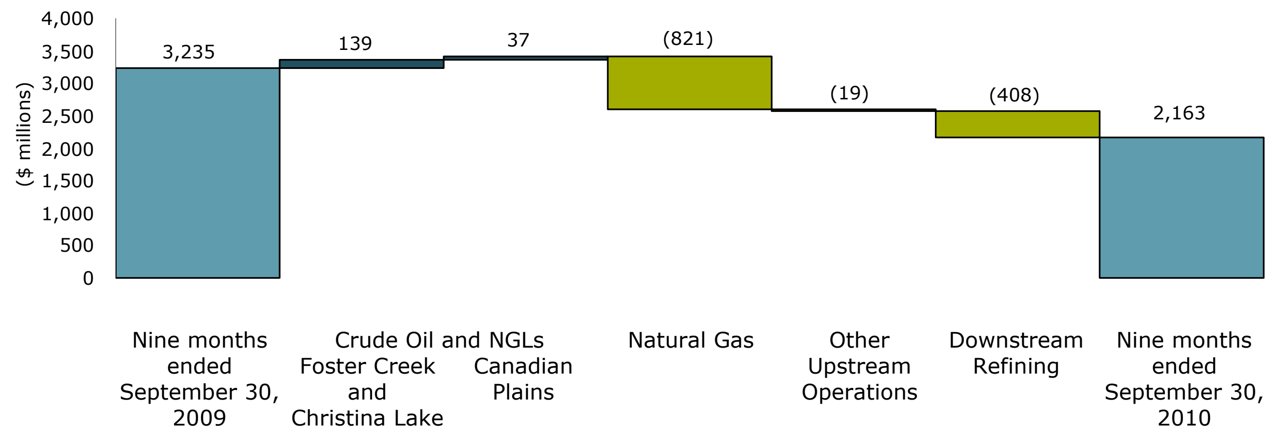
Three Months Ended September 30, 2010 compared to 2009



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

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

Nine Months Ended September 30, 2010 compared to 2009



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

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

CASH FLOW

Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash Flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

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

Three Months Ended September 30, 2010 compared to 2009
In the third quarter of 2010 Cash Flow decreased $415 million primarily due to:
- A 37 percent decrease in the realized average natural gas price, including the impact of hedges, to $4.77 per Mcf compared to $7.55 per Mcf;
- A decrease in Operating Cash Flow from Downstream Refining of $127 million;
- An increase in royalties of $28 million primarily as a result of Foster Creek achieving royalty payout and higher WTI prices used for determining royalties;
- A realized foreign exchange loss of $14 million in 2010 compared to a gain of $14 million in 2009;
- A three percent decrease in our realized average liquids price, including the impact of hedging, to $61.81 per bbl compared to $63.84 per bbl;
- Natural gas production declining 11 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production; and
- An increase in net interest expense of $15 million.

The decreases in our third quarter 2010 Cash Flow were partially offset by:
- A $107 million decrease in current income tax expense as a result of lower realized hedging gains and utilizing claims from tax pools that we received as a result of the Arrangement; and
- A one percent increase in our crude oil and NGLs production volumes.

Nine Months Ended September 30, 2010 compared to 2009
Cash Flow for the nine months ended September 30, 2010 decreased $843 million mainly due to:
- A 37 percent decrease in the realized average natural gas price, including the impact of hedges, to $5.19 per Mcf compared to $8.19 per Mcf;
- A decrease in Operating Cash Flow from Downstream Refining of $408 million;
- An increase in royalties of $166 million, primarily as a result of Foster Creek achieving royalty payout and higher crude oil prices;
- Natural gas production declining 11 percent;
- Higher crude oil and NGLs operating costs consistent with the increase in production;
- An increase in general and administrative and net interest expenses of $62 million; and
- A realized foreign exchange loss of $16 million compared to a gain of $30 million.

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

OPERATING EARNINGS

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

(1) The unrealized mark-to-market accounting gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gains or losses on discontinuance, after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments, after-tax gains (losses) on non-operating foreign exchange and the effect of changes in statutory income tax rates.

We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of Operating Earnings has been prepared to provide information that is more comparable between periods. The items identified above that affected our Cash Flow and identified below that affected our Net Earnings also impacted our Operating Earnings.

The declines in our Operating Earnings for the three and nine months ended September 30, 2010 compared to 2009 were consistent with the decreases to our Operating Cash Flow and Cash Flow, details of which can be found above.

NET EARNINGS VARIANCE

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

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

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

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

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

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

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Changes in the mark-to-market gain or loss on these agreements affect our Net Earnings and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. The following information has been provided in order to provide information that is more comparable between periods:

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

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

NET CAPITAL INVESTMENT

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

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

Acquisitions and Divestitures

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

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

FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of Free Cash Flow, which is defined as Cash Flow in excess of Capital Investment, excluding acquisitions and divestitures. Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

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

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

RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

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

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

Natural Gas Production Volumes

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

During 2009 and 2010, we chose to restrict capital spending on natural gas drilling, completion and tie-in activity in favour of increasing investment in crude oil projects. As a result our overall natural gas production has decreased 11 percent in the third quarter and 11 percent year to date to 754 MMcf/d. Quarterly production volumes declined 10 percent in Southern Alberta (year to date – 10 percent) compared to the same quarter of 2009. Weather related delays experienced throughout 2010 also negatively impacted our natural gas production. Further detail on the changes in our production can be found in the Divisional Results section of this MD&A.

Operating Netbacks - Quarter

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

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

Operating Netbacks – Year to Date

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

In the first nine months of 2010, our average netback for liquids, excluding realized financial hedging, increased by $3.26 per bbl primarily due to an increase in prices partially offset by higher royalties and operating expenses. Our average netback for natural gas, excluding realized financial hedges, was consistent with 2009.

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

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

DIVISIONAL RESULTS

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

INTEGRATED OIL DIVISION

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

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

FOSTER CREEK AND CHRISTINA LAKE

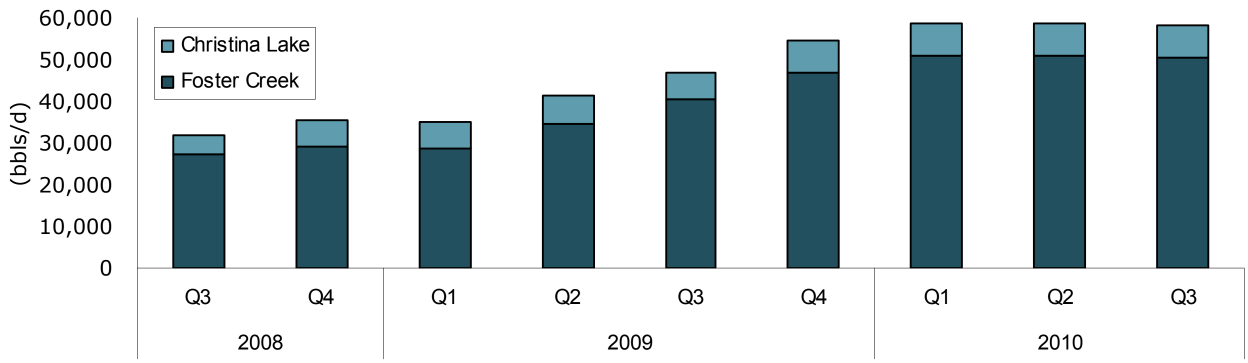
Financial Results

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

Production Volumes

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

Production Volumes by Quarter



Net Revenues Variance

Three Months Ended September 30, 2010 compared to 2009

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

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

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

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

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

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

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

Nine Months Ended September 30, 2010 compared to 2009

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

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

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

Foster Creek production increased 47 percent primarily as a result of the phase D and E expansions which commenced production late in the first quarter of 2009 combined with well optimizations and increased production from wedge wells. The 18 percent increase in production at Christina Lake was a result of increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake.

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

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

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

DOWNSTREAM REFINING

Financial Results

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

Refinery Operations [1]

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

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

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

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

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

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

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

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

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

INTEGRATED OIL DIVISION - OTHER PROPERTIES

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

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

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

Our Upstream capital investment in 2010 was primarily focused on the continued development of the next phases of the Foster Creek and Christina Lake projects. Our current plan is to increase production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the expected completion of Christina Lake phase C in 2011 and phase D in 2013.

Foster Creek capital investment in the third quarter and year to date is lower than 2009 as we awaited regulatory approvals, which were received late in the third quarter, for the next phases of expansion (F, G and H). The majority of Foster Creek spending is related to drilling stratigraphic test wells, debottlenecking portions of the plant and spending in preparation for the next phase of expansion.

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

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

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

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

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

Our Downstream Refining capital investment in 2010 continued to focus on the CORE project at the Wood River refinery. For 2010, of the $438 million capital expenditures at Wood River, $372 million were related to the CORE project. At September 30, 2010, the CORE project is approximately 87 percent complete. Unanticipated high water levels on the Mississippi River caused delays in the delivery schedule of various modules, which resulted in a shift to the timeline for this project. Commissioning of several of the process units has been completed with an expected coker startup in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach US$3.7 billion (50 percent net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (50 percent net to Cenovus), or about 10 percent higher than originally forecast. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d.

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

CANADIAN PLAINS DIVISION

Crude Oil and NGLs

Financial Results

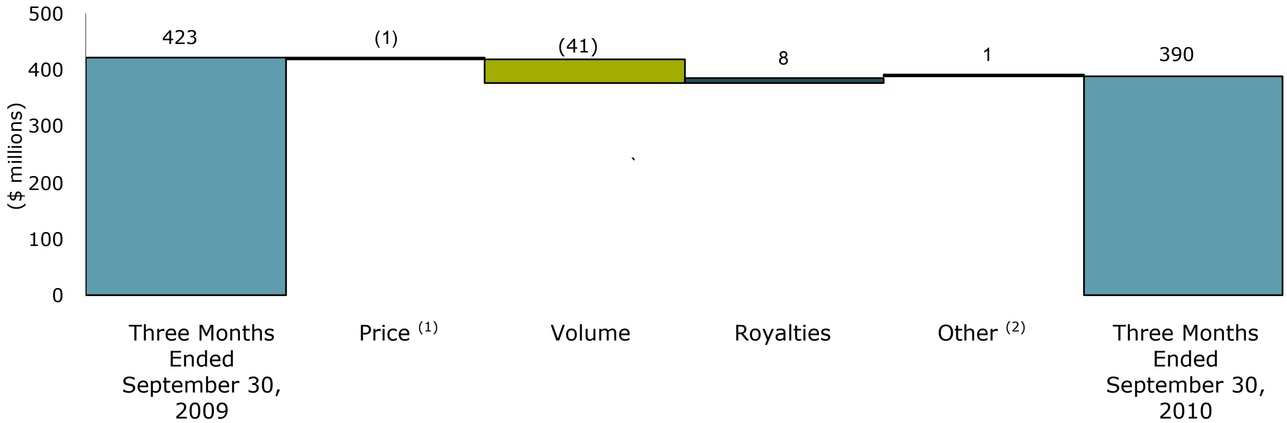
	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2010**	2009	**2010**	2009
Revenues	**$ 435**	$ 489	**$ 1,419**	$ 1,274
Deduct (add)				
Realized financial hedging (gain) loss	**(13)**	-	**(7)**	(3)
Royalties	**58**	66	**204**	143
Net revenues	**390**	423	**1,222**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

Production Volumes

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

Net Revenues Variance

Three Months Ended September 30, 2010 compared to 2009



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

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

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

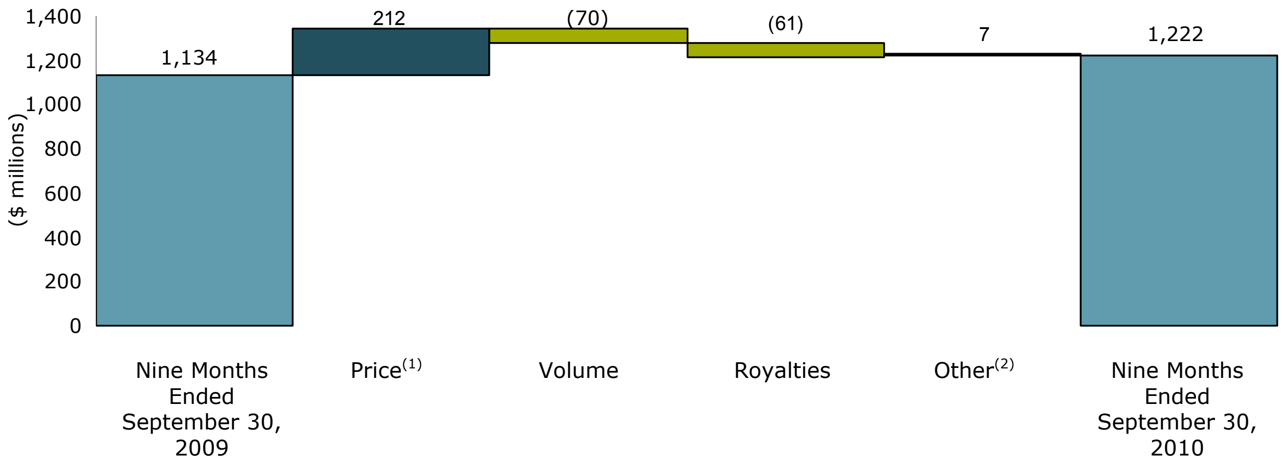
Royalties in the third quarter were $8 million lower than 2009 as a result of lower volumes as well as adjustments related to prior years. The effective crude oil royalty rate in the third quarter of 2010 was 14.9 percent (2009 – 15.0 percent).

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

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

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

Nine Months Ended September 30, 2010 compared to 2009



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

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

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

Royalties for the nine months were $61 million higher than the same period in 2009 as a result of higher commodity prices, as well as higher royalty rates arising from the higher commodity prices, which resulted in an effective royalty rate of 16.4 percent for the period compared to 13.2 percent for 2009. The higher royalty rate was partially offset by lower volumes.

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

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

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

Natural Gas

Financial Results

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

Production Volumes

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

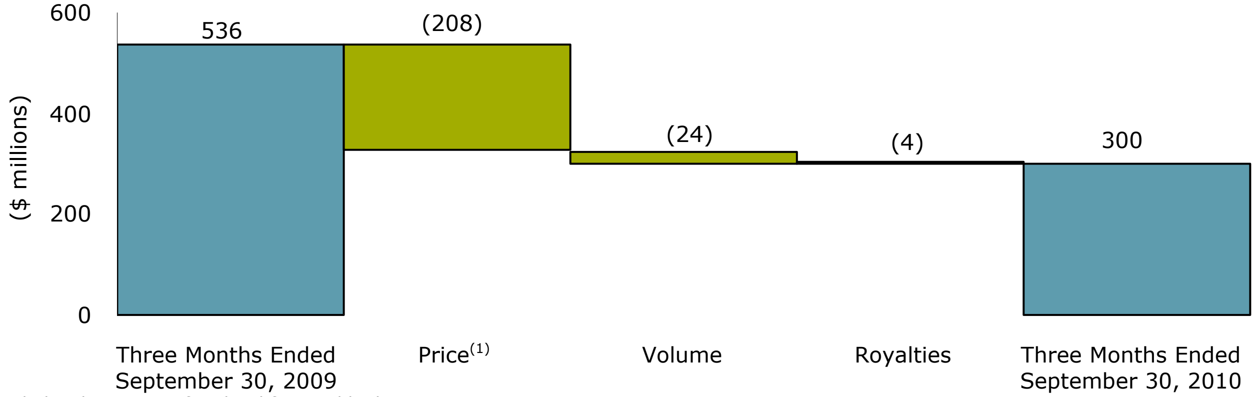
The increase in the average natural gas price, excluding realized financial hedges, to $3.70 per Mcf in the third quarter from $3.15 per Mcf in the third quarter of 2009 was consistent with the increase in the benchmark AECO price. The third quarter realized financial hedging gain of $68 million ($1.06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

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

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

Net Revenues Variance

Three Months Ended September 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

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

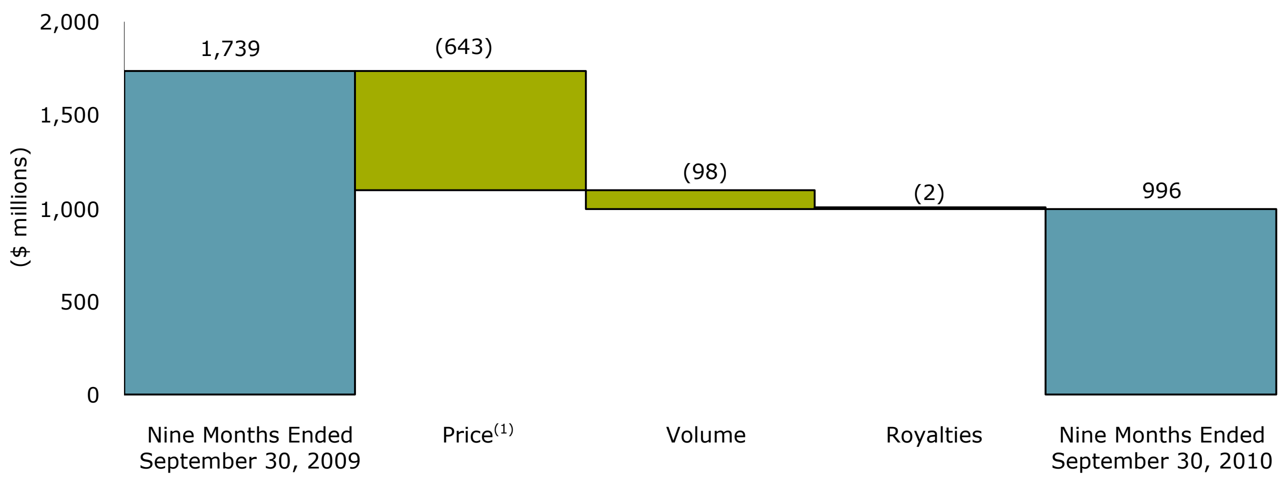
Royalties in the third quarter increased by $4 million compared to 2009 due primarily to a payment for royalties on previous years' production, resulting in an effective royalty rate of 2.3 percent (2009 – 0.4 percent).

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

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

Operating expenses were consistent with the third quarter of 2009.

Nine Months Ended September 30, 2010 Compared to 2009



(1) Includes the impact of realized financial hedging.

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

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

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

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

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

Canadian Plains - Other

Financial Results

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

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

Capital Investment

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

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

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

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

CORPORATE AND ELIMINATIONS

Financial Results

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

The Corporate and Eliminations segment includes revenues that represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices. The segment also includes inter-segment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. Operating expenses primarily relate to mark-to-market gains and losses on long-term power purchase contracts and downstream crude oil supply positions. DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

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

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

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

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

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

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

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

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

DEPRECIATION, DEPLETION and AMORTIZATION

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

We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream Canada DD&A in the third quarter and year to date were lower primarily as a result of a lower DD&A rate because of the addition of proved reserves at Christina Lake phase D at the end of 2009. Decreases to our Downstream Refining DD&A were primarily due to a strengthening of the Canadian dollar average exchange rate.

INCOME TAX

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

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

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

Our effective tax rate for the third quarter of 2010 was 22.0 percent (year to date - 17.0 percent) compared to 31.8 percent in 2009 (year to date – 19.8 percent). The decreases for the quarter and nine months ended are primarily due to the impact of permanent differences and the recognition of the future tax benefit arising from a loss in our U.S. entities in 2010 compared to earnings in 2009.

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

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:
- The non-taxable portion of Canadian capital gains and losses;
- International financing; and
- Taxable foreign exchange (gains) losses not included in Net Earnings.

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

LIQUIDITY AND CAPITAL RESOURCES

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

OPERATING ACTIVITIES

Net cash from operating activities decreased $769 million in the third quarter compared to 2009 and decreased $953 million in the first nine months compared to 2009 mainly because of lower Cash Flow. Cash Flow was $509 million during the third quarter (2009 - $924 million) and $1,767 million for the first nine months (2009 - $2,610 million). Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by the net change in other assets and liabilities and the net change in non-cash working capital.

Excluding the impact of risk management assets and liabilities, we had working capital of $589 million at September 30, 2010 compared to working capital of $479 million at December 31, 2009. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities for the three months ended September 30, 2010 decreased to $299 million from $4,375 million for the same period in 2009. Year to date net cash used in investing of $1,139 million was a decrease of $4,486 million from the same period in 2009. A substantial portion of the decrease in cash used in investing activities is related to cash that was restricted in 2009 as part of the Arrangement. Capital expenditures decreased in the third quarter to $484 million compared to $516 million in 2009 while year to date capital expenditures decreased by $203 million to $1,454 million compared to 2009. Total divestiture proceeds in 2010 of $312 million include $168 million which occurred in the third quarter. The changes to our capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

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

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

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

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

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

FINANCIAL METRICS

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

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Adjusted Earnings before Interest, Income Taxes, DD&A, Accretion of asset retirement obligations, foreign exchange gains/losses, gains/losses on disposal of assets and other income/loss. Debt is defined as the current and long-term portions of long-term debt. These metrics are used to steward Cenovus's capital structure.

We target a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our capital structure can be found in the notes to the Interim Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at September 30, 2010 there were 752.0 million common shares outstanding and no first preferred shares or second preferred shares outstanding.

During the second quarter of 2010, the Board approved a dividend reinvestment plan ("DRIP"), which permits holders of common shares to automatically reinvest all or any portion of the cash dividends paid on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury at the average market price or purchased on the market. For the period ended September 30, 2010, no common shares were issued from treasury to meet our DRIP requirements. Further information can be found on our website.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims.

RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risks (such as commodity price, foreign exchange and interest rates), credit and liquidity risks;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

We are committed to identifying and managing these risks in the near-term as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board approved Corporate Risk Management Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A.

ENVIRONMENTAL REGULATION AND RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for our exploration, development and production of oil and gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval is generally required before initiating, advancing or changing operations projects. Further information regarding the status of each project can be found in the Divisional Results section of this MD&A.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emissions are in various phases of review, discussion or implementation in the U.S. and Canada. These include proposed federal legislation and state actions in the U.S. to develop statewide or regional programs, each of which could impose reductions in GHG emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector. A fulsome assessment of potential regulations, our corporate strategy and performance is provided in our MD&A for the year ended December 31, 2009 and our response to the Carbon Disclosure Project can be found on our website. We will continue to provide quarterly updates to that information.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

We are reviewing our existing Corporate Responsibility ("CR") policy to ensure that it continues to drive our commitments, strategy and reporting, and also enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators.

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

As our CR reporting process matures, indicators will be developed that better reflect Cenovus's operations and challenges. These indicators will be integrated into our CR reporting and will expand our online presence through our website.

ALBERTA'S ROYALTY FRAMEWORK

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

ALBERTA'S REGULATORY FRAMEWORK

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

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act, sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while considering social and economic impacts. In August, the Lower Athabasca Regional Advisory Council ("RAC") provided its vision document to the Government of Alberta regarding the LARP, which is expected to be drafted and published for comment in early 2011. Cenovus is actively participating in the feedback process as a stakeholder with significant activities in the region and will continue to monitor developments going forward. It is possible that the RAC vision, if adopted in its current form by the Government of Alberta, may negatively impact Cenovus's access to certain resource properties.

ACCOUNTING POLICIES AND ESTIMATES

BASIS OF PRESENTATION

Our results for the nine month period from January 1 to September 30, 2010 and the one month period from December 1 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

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

The presentation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of Encana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the periods presented.

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

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations," which replaces CICA Handbook Section 1581 of the same name. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the Statement of Earnings. The adoption of this standard did not impact the Company's Interim Consolidated Financial Statements for the period ended September 30, 2010. However, the adoption of this new standard will impact the accounting treatment of future business combinations.

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements." Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest to be classified as a separate component of equity. In addition, Net Earnings, and components of other comprehensive income are attributed to both the parent and non-controlling interest. The early adoption of these standards did not have a material impact on the Company's Interim Consolidated Financial Statements for the period ended September 30, 2010.

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

RECENT ACCOUNTING PRONOUNCEMENTS

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

INTERNATIONAL FINANCIAL REPORTING STANDARDS

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

IFRS Accounting Policies

The IFRS accounting policies that we expect to use have not changed from those described in our MD&A for the three month period March 31, 2010 and for the year ended December 31, 2009. We are continuing to monitor any new or amended IFRS issued by the International Accounting Standards Board that could affect our choice of accounting policies, including the new joint ventures standard that is expected to be published later in 2010.

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

IFRS Opening Balance Sheet

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

Upstream Property, Plant & Equipment (“PP&E”)

To prepare the draft IFRS opening balance sheet, we chose to apply the IFRS 1 exemption for full cost oil & gas companies. Using the exemption, we re-classified the cost of our unproved properties from Upstream PP&E to a new asset category, Exploration and Evaluation. We allocated the remainder of our Upstream PP&E full cost pool to our IFRS areas based on the relative fair value of each area. Fair value was calculated using the estimated future net cash flows from proved reserves, discounted at 10 percent, since this was considered to be an appropriate estimate of the relative fair value of each of our IFRS areas and was consistent with the allocation process used in the formation of Cenovus. The allocation process did not affect the net book value of our Upstream PP&E as no IFRS impairments were recognized as of January 1, 2010. In terms of our asset retirement obligation, the historical credit-adjusted risk free rates that are used in the calculation under Canadian GAAP were changed to their current rate under IFRS, which did not change the obligation significantly. As a result of applying the IFRS 1 exemption to our full cost pool, the change in the asset retirement obligation was recognized as a charge to equity.

Downstream PP&E

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

Other Draft IFRS Opening Balance Sheet Matters

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

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

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

Income Tax

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

Paid in Surplus

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

IFRS Results and Financial Statements

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

Internal Controls Over Financial Reporting and Disclosure Controls and Procedures

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

Financial Reporting Expertise

In terms of financial literacy, we continued our formal IFRS education sessions in the third quarter. Our education efforts will continue for the remainder of 2010 and into 2011. The education of our external stakeholders is expected to continue throughout 2010 and into 2011, as we calculate the quarterly adjustments from Canadian GAAP to IFRS.

OUTLOOK

Our long term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties. We also have an extensive inventory of emerging oil sands projects, and we have a 100 percent working interest in many of these projects;
- Continue the development of our resources in multiple phases using a low cost manufacturing-like approach;
- Leadership in low cost oil sands development enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- Internally funded growth through Free Cash Flow generation from our established crude oil and natural gas assets;
- Maintaining a lower risk profile through natural gas and downstream integration as well as a consistent hedging strategy; and
- Maintaining a meaningful dividend.

We expect that global oil demand will continue to increase which should allow for modest increases in WTI prices while we are expecting the light-heavy differential to remain relatively strong compared to historical trends despite some weakening in 2011 as Canadian heavy crude supply grows in advance of new coking capacity and pipeline access to the Gulf of Mexico. Offsetting this is a relatively weak price outlook for natural gas and refining margins. The key challenges that need to be effectively managed to enable our growth are commodity price volatility, partner approvals, government project approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our 2010 results is discussed in the Risk Management section of this MD&A and in our Annual Information Form ("AIF") for the year ended December 31, 2009.

We expect our 2010 capital investment program to be funded from Cash Flow. We also have a plan to divest of certain non-core assets and to date have received proceeds of $312 million. Our conventional crude oil and natural gas assets in Alberta and Saskatchewan are key to providing Free Cash Flow to enable oil sands growth. Our ten year business plan outlines how Cenovus expects to reach net oil sands production of 300,000 bbls/d by the end of 2019. We are planning continued expansions at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve this objective.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have benefitted from this strategy in both 2009 and 2010, we cannot ensure that we will continue to derive such benefits in the future.

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

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

ADVISORY

FORWARD-LOOKING INFORMATION

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

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

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

Forward-looking statements involve a number of assumptions, risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The risk factors and uncertainties that could cause actual results to differ materially, and the factors or assumptions on which the forward-looking information is based, include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions inherent in our current guidance; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the effect of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; success of hedging strategies; maintaining a desirable debt to cash flow ratio; accuracy of our reserves, resources and future production estimates; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate the North American integrated heavy oil business and to obtain necessary regulatory approvals; the successful and timely implementation of capital projects; reliability of our assets; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining synthetic crude oil; risks associated with technology and its application to our business; our ability to generate sufficient cash flow from operations to meet our current and future obligations; our ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or the interpretations of such laws or regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on us, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we operate; risks associated with existing and potential future lawsuits and regulatory actions made against us; our financing plans and initiatives; the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders and our ability to realize the expected benefits of the Arrangement; our ability to obtain financing in the future on a stand alone basis; the historical financial information pertaining to our assets as operated by Encana prior to November 30, 2009 may not be representative of our results as an independent entity; our limited operating history as a separate entity and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities. Readers are cautioned that the foregoing list is not exhaustive.

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

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

CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

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

ABBREVIATIONS

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

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

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by Canadian GAAP such as Cash Flow, Operating Cash Flow, Free Cash Flow, Operating Earnings, Adjusted EBITDA, Debt and Capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with Canadian GAAP. The definition and reconciliation of each non-GAAP measure, is presented in this MD&A.

REFERENCES TO CENOVUS

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

Additional information regarding Cenovus Energy Inc. can be found on our website at www.cenovus.com.

CONSOLIDATED STATEMENT OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended September 30, ($ millions, except per share amounts)		Three Months Ended **2010**	Three Months Ended 2009	Nine Months Ended **2010**	Nine Months Ended 2009
Gross Revenues	*(Note 1)*	**3,222**	3,080	**10,142**	8,687
Less: Royalties		**107**	79	**341**	175
Net Revenues		**3,115**	3,001	**9,801**	8,512
Expenses	*(Note 1)*				
Production and mineral taxes		**8**	11	**26**	37
Transportation and selling		**213**	194	**795**	544
Operating		**322**	295	**992**	979
Purchased product		**1,849**	1,718	**5,502**	4,279
Depreciation, depletion and amortization		**315**	391	**964**	1,153
General and administrative		**49**	49	**160**	142
Interest, net	*(Note 7)*	**79**	64	**210**	166
Accretion of asset retirement obligation	*(Note 13)*	**18**	11	**58**	34
Foreign exchange (gain) loss, net	*(Note 8)*	**(24)**	120	**(23)**	211
(Gain) loss on divestiture of assets		**-**	-	**9**	-
Other (income) loss, net		**-**	-	**(1)**	-
		2,829	2,853	**8,692**	7,545
Earnings Before Income Tax		**286**	148	**1,109**	967
Income tax expense	*(Note 9)*	**63**	47	**189**	191
Net Earnings		**223**	101	**920**	776
Other Comprehensive Income, Net of Tax					
Foreign Currency Translation Adjustment		**28**	(160)	**69**	(177)
Comprehensive Income		**251**	(59)	**989**	599
Net Earnings per Common Share	*(Note 18)*				
Basic		**0.30**	0.13	**1.22**	1.03
Diluted		**0.30**	0.13	**1.22**	1.03

See accompanying Notes to Interim Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEET (unaudited)

As at ($ millions)		September 30, 2010	December 31, 2009
Assets			
Current Assets			
Cash and cash equivalents		**464**	155
Accounts receivable and accrued revenues		**1,051**	978
Income tax receivable		**-**	40
Current portion of Partnership Contribution Receivable	*(Note 11)*	**353**	345
Risk management	*(Note 17)*	**262**	60
Inventories	*(Note 10)*	**862**	875
		2,992	2,453
Property, Plant and Equipment, net	*(Notes 1, 6)*	**15,258**	15,214
Partnership Contribution Receivable	*(Note 11)*	**2,313**	2,621
Risk Management	*(Note 17)*	**79**	1
Other Assets		**411**	320
Goodwill	*(Note 1)*	**1,146**	1,146
		22,199	21,755
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**1,692**	1,574
Income tax payable		**99**	-
Current portion of Partnership Contribution Payable	*(Note 11)*	**350**	340
Risk management	*(Note 17)*	**22**	70
		2,163	1,984
Long-Term Debt	*(Note 12)*	**3,574**	3,656
Partnership Contribution Payable	*(Note 11)*	**2,344**	2,650
Risk Management	*(Note 17)*	**11**	4
Asset Retirement Obligation	*(Note 13)*	**1,125**	1,147
Other Liabilities		**351**	239
Future Income Taxes		**2,472**	2,467
		12,040	12,147
Shareholders' Equity		**10,159**	9,608
		22,199	21,755

See accompanying Notes to Interim Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(unaudited)

($ millions)	Share Capital *(Note 14)*	Paid in Surplus	Retained Earnings	AOCI*	Owner's Net Investment (Note 14)	Total
Balance as of December 31, 2008	-	-	-	224	9,264	9,488
Net earnings	-	-	-	-	776	776
Net distribution to owner	-	-	-	-	(525)	(525)
Other comprehensive income (loss)	-	-	-	(177)	-	(177)
Balance as of September 30, 2009	-	-	-	47	9,515	9,562
Balance as of December 31, 2009	3,681	5,896	45	(14)	-	9,608
Net earnings	-	-	920	-	-	920
Common Shares issued under option plans	12	-	-	-	-	12
Dividends on Common Shares	-	-	(450)	-	-	(450)
Other comprehensive income (loss)	-	-	-	69	-	69
Balance as of September 30, 2010	**3,693**	**5,896**	**515**	**55**	**-**	**10,159**

*Accumulated Other Comprehensive Income

See accompanying Notes to Interim Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENT OF CASH FLOWS (unaudited)

For the period ended September 30, ($ millions)		Three Months Ended 2010	2009	Nine Months Ended 2010	2009
Operating Activities					
Net earnings		**223**	101	**920**	776
Depreciation, depletion and amortization		**315**	391	**964**	1,153
Future income taxes	*(Note 9)*	**33**	(90)	**129**	(195)
Unrealized (gain) loss on risk management	*(Note 17)*	**(62)**	351	**(321)**	562
Unrealized foreign exchange (gain) loss	*(Note 8)*	**(38)**	134	**(39)**	241
Accretion of asset retirement obligation	*(Note 13)*	**18**	11	**58**	34
(Gain) loss on divestiture of assets		**-**	-	**9**	-
Other		**20**	26	**47**	39
Net change in other assets and liabilities		**(13)**	(3)	**(41)**	(12)
Net change in non-cash working capital		**149**	493	**210**	291
Cash From Operating Activities		**645**	1,414	**1,936**	2,889
Investing Activities					
Capital expenditures	*(Note 1)*	**(484)**	(516)	**(1,454)**	(1,657)
Proceeds from divestitures	*(Note 6)*	**168**	(2)	**312**	1
Net change in investments and other		**1**	-	**3**	14
Restricted cash	*(Note 12)*	**-**	(3,880)	**-**	(3,880)
Net change in non-cash working capital		**16**	23	**-**	(103)
Cash (Used in) Investing Activities		**(299)**	(4,375)	**(1,139)**	(5,625)
Net Cash Provided (Used) before Financing Activities		**346**	(2,961)	**797**	(2,736)
Financing Activities					
Net issuance (repayment) of revolving long-term debt		**(142)**	(383)	**(36)**	(546)
Net financing transactions with Encana		**-**	(203)	**-**	(525)
Issuance of long-term debt		**-**	-	**-**	204
Issuance of Cenovus notes	*(Note 12)*	**-**	3,718	**-**	3,718
Repayment of long-term debt		**-**	(97)	**-**	(97)
Issuance of Common Shares		**4**	-	**11**	-
Dividends on Common Shares		**(150)**	-	**(450)**	-
Cash From (Used in) Financing Activities		**(288)**	3,035	**(475)**	2,754
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(3)**	(3)	**(13)**	(8)
Increase (Decrease) in Cash and Cash Equivalents		**55**	71	**309**	10
Cash and Cash Equivalents, Beginning of Period		**409**	127	**155**	188
Cash and Cash Equivalents, End of Period		**464**	198	**464**	198

See accompanying Notes to Interim Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. ("Cenovus" or the "Company") is in the business of the development, production and marketing of crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States ("U.S.").

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

Cenovus is organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with the Company's joint venture partner, as well as other oil sands interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major oil sands projects: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.

- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major oil properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

For financial statement reporting purposes, the Company's operating and reportable segments are:

- **Upstream Canada,** which includes Cenovus's development and production of crude oil, natural gas and NGLs, and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips, an unrelated U.S. public company, and operated by Cenovus, as well as several other emerging projects.

- **Downstream Refining,** which is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with ConocoPhillips and operated by ConocoPhillips.

- **Corporate and Eliminations,** which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The tabular financial information which follows presents the segmented information first by segment and geographic location, then by product and operating division. Capital expenditures and goodwill information are summarized at the end of the note.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations

Segment and Geographic Information (For the three months ended September 30)

	Upstream Canada		Downstream Refining	
	2010	2009	**2010**	2009
Gross Revenues	**1,601**	1,706	**1,584**	1,766
Less: Royalties	**107**	79	**-**	-
Net Revenues	**1,494**	1,627	**1,584**	1,766
Expenses				
Production and mineral taxes	**8**	11	**-**	-
Transportation and selling	**213**	194	**-**	-
Operating	**201**	182	**117**	110
Purchased product	**380**	201	**1,499**	1,561
Operating Cash Flow	**692**	1,039	**(32)**	95
Depreciation, depletion and amortization	**267**	336	**44**	54
Segment Income (Loss)	**425**	703	**(76)**	41

	Corporate and Eliminations		Consolidated	
	2010	2009	**2010**	2009
Gross Revenues	**37**	(392)	**3,222**	3,080
Less: Royalties	**-**	-	**107**	79
Net Revenues	**37**	(392)	**3,115**	3,001
Expenses				
Production and mineral taxes	**-**	-	**8**	11
Transportation and selling	**-**	-	**213**	194
Operating	**4**	3	**322**	295
Purchased product	**(30)**	(44)	**1,849**	1,718
	63	(351)	**723**	783
Depreciation, depletion and amortization	**4**	1	**315**	391
Segment Income (Loss)	**59**	(352)	**408**	392
General and administrative	**49**	49	**49**	49
Interest, net	**79**	64	**79**	64
Accretion of asset retirement obligation	**18**	11	**18**	11
Foreign exchange (gain) loss, net	**(24)**	120	**(24)**	120
(Gain) loss on disposal of assets	**-**	-	**-**	-
Other (income) loss, net	**-**	-	**-**	-
	122	244	**122**	244
Earnings Before Income Tax			**286**	148
Income tax expense			**63**	47
Net Earnings			**223**	101

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Canada Product and Divisional Information
(For the three months ended September 30)

	Crude Oil & NGLs					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**435**	386	**448**	489	**883**	875
Less: Royalties	**42**	8	**58**	66	**100**	74
Net Revenues	**393**	378	**390**	423	**783**	801
Expenses						
Production and mineral taxes	**-**	-	**7**	7	**7**	7
Transportation and selling	**158**	131	**45**	41	**203**	172
Operating	**56**	49	**76**	61	**132**	110
Purchased product	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**179**	198	**262**	314	**441**	512

	Natural Gas					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**22**	45	**305**	537	**327**	582
Less: Royalties	**-**	1	**5**	1	**5**	2
Net Revenues	**22**	44	**300**	536	**322**	580
Expenses						
Production and mineral taxes	**-**	-	**1**	3	**1**	3
Transportation and selling	**-**	1	**10**	12	**10**	13
Operating	**5**	4	**60**	60	**65**	64
Purchased product	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**17**	39	**229**	461	**246**	500

	Other					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**2**	39	**389**	210	**391**	249
Less: Royalties	**2**	3	**-**	-	**2**	3
Net Revenues	**-**	36	**389**	210	**389**	246
Expenses						
Production and mineral taxes	**-**	1	**-**	-	**-**	1
Transportation and selling	**-**	9	**-**	-	**-**	9
Operating	**1**	4	**3**	4	**4**	8
Purchased product	**-**	-	**380**	201	**380**	201
Operating Cash Flow	**(1)**	22	**6**	5	**5**	27

	Total Upstream Canada					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**459**	470	**1,142**	1,236	**1,601**	1,706
Less: Royalties	**44**	12	**63**	67	**107**	79
Net Revenues	**415**	458	**1,079**	1,169	**1,494**	1,627
Expenses						
Production and mineral taxes	**-**	1	**8**	10	**8**	11
Transportation and selling	**158**	141	**55**	53	**213**	194
Operating	**62**	57	**139**	125	**201**	182
Purchased product	**-**	-	**380**	201	**380**	201
Operating Cash Flow	**195**	259	**497**	780	**692**	1,039

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations

Segment and Geographic Information (For the nine months ended September 30)

	Upstream Canada		Downstream Refining	
	2010	2009	**2010**	2009
Gross Revenues	**5,194**	4,860	**4,712**	4,446
Less: Royalties	**341**	175	**-**	-
Net Revenues	**4,853**	4,685	**4,712**	4,446
Expenses				
Production and mineral taxes	**26**	37	**-**	-
Transportation and selling	**795**	544	**-**	-
Operating	**621**	568	**366**	386
Purchased product	**1,186**	647	**4,408**	3,714
Operating Cash Flow	**2,225**	2,889	**(62)**	346
Depreciation, depletion and amortization	**796**	956	**144**	171
Segment Income (Loss)	**1,429**	1,933	**(206)**	175

As at	**September 30, 2010**	December 31, 2009	**September 30, 2010**	December 31, 2009
Property, Plant & Equipment	**9,848**	10,109	**5,293**	4,989
Goodwill	**1,146**	1,146	**-**	-
Total Assets	**14,637**	15,218	**6,530**	6,107

	Corporate and Eliminations		Consolidated	
	2010	2009	**2010**	2009
Gross Revenues	**236**	(619)	**10,142**	8,687
Less: Royalties	**-**	-	**341**	175
Net Revenues	**236**	(619)	**9,801**	8,512
Expenses				
Production and mineral taxes	**-**	-	**26**	37
Transportation and selling	**-**	-	**795**	544
Operating	**5**	25	**992**	979
Purchased product	**(92)**	(82)	**5,502**	4,279
	323	(562)	**2,486**	2,673
Depreciation, depletion and amortization	**24**	26	**964**	1,153
Segment Income (Loss)	**299**	(588)	**1,522**	1,520
General and administrative	**160**	142	**160**	142
Interest, net	**210**	166	**210**	166
Accretion of asset retirement obligation	**58**	34	**58**	34
Foreign exchange (gain) loss, net	**(23)**	211	**(23)**	211
(Gain) loss on disposal of assets	**9**	-	**9**	-
Other (income) loss, net	**(1)**	-	**(1)**	-
	413	553	**413**	553
Earnings Before Income Tax			**1,109**	967
Income tax expense			**189**	191
Net Earnings			**920**	776

As at	**September 30, 2010**	December 31, 2009	**September 30, 2010**	December 31, 2009
Property, Plant & Equipment	**117**	116	**15,258**	15,214
Goodwill	**-**	-	**1,146**	1,146
Total Assets	**1,032**	430	**22,199**	21,755

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Canada Product and Divisional Information
(For the nine months ended September 30)

	Crude Oil & NGLs					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**1,457**	916	**1,426**	1,277	**2,883**	2,193
Less: Royalties	**115**	11	**204**	143	**319**	154
Net Revenues	**1,342**	905	**1,222**	1,134	**2,564**	2,039
Expenses						
Production and mineral taxes	**-**	-	**22**	23	**22**	23
Transportation and selling	**595**	330	**165**	155	**760**	485
Operating	**177**	144	**230**	188	**407**	332
Purchased product	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**570**	431	**805**	768	**1,375**	1,199

	Natural Gas					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**72**	165	**1,010**	1,751	**1,082**	1,916
Less: Royalties	**6**	1	**14**	12	**20**	13
Net Revenues	**66**	164	**996**	1,739	**1,062**	1,903
Expenses						
Production and mineral taxes	**-**	-	**4**	13	**4**	13
Transportation and selling	**1**	2	**34**	37	**35**	39
Operating	**16**	18	**179**	184	**195**	202
Purchased product	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**49**	144	**779**	1,505	**828**	1,649

	Other					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**10**	74	**1,219**	677	**1,229**	751
Less: Royalties	**2**	8	**-**	-	**2**	8
Net Revenues	**8**	66	**1,219**	677	**1,227**	743
Expenses						
Production and mineral taxes	**-**	1	**-**	-	**-**	1
Transportation and selling	**-**	20	**-**	-	**-**	20
Operating	**4**	19	**15**	15	**19**	34
Purchased product	**-**	-	**1,186**	647	**1,186**	647
Operating Cash Flow	**4**	26	**18**	15	**22**	41

	Total Upstream Canada					
	Integrated Oil		Canadian Plains		Total	
	2010	2009	**2010**	2009	**2010**	2009
Gross Revenues	**1,539**	1,155	**3,655**	3,705	**5,194**	4,860
Less: Royalties	**123**	20	**218**	155	**341**	175
Net Revenues	**1,416**	1,135	**3,437**	3,550	**4,853**	4,685
Expenses						
Production and mineral taxes	**-**	1	**26**	36	**26**	37
Transportation and selling	**596**	352	**199**	192	**795**	544
Operating	**197**	181	**424**	387	**621**	568
Purchased product	**-**	-	**1,186**	647	**1,186**	647
Operating Cash Flow	**623**	601	**1,602**	2,288	**2,225**	2,889

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Capital Expenditures

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Integrated Oil	**157**	119	**455**	396
Canadian Plains	**166**	104	**407**	438
Upstream Canada	**323**	223	**862**	834
Downstream Refining	**146**	291	**516**	808
Corporate	**11**	1	**25**	13
	480	515	**1,403**	1,655
Acquisition Capital				
Integrated Oil	**-**	-	**18**	-
Canadian Plains	**4**	1	**20**	2
Corporate	**-**	-	**13**	-
Total	**484**	516	**1,454**	1,657

Goodwill Additions

There were no additions to goodwill during 2010 or 2009.

2. BACKGROUND & BASIS OF PRESENTATION

Cenovus was created on November 30, 2009 and began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana and the other an integrated oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held. Common Shares of Cenovus began trading on a "when issued" basis on the Toronto ("TSX") and New York ("NYSE") stock exchanges on November 2, 2009. Regular trading of Cenovus shares began on the TSX on December 3, 2009 and on the NYSE on December 9, 2009.

Basis of presentation / Carve-out financial information for comparative periods

These interim Consolidated Financial Statements have been presented in accordance with Canadian generally accepted accounting principles ("GAAP") and have been prepared following the same accounting policies and methods of computation as the Cenovus annual audited Consolidated Financial Statements for the year ended December 31, 2009, except as outlined in Notes 3 and 4. The disclosures provided below are incremental to those included with the Cenovus annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the Cenovus annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2009.

Since the Company was created on November 30, 2009 and began independent operations on December 1, 2009, the comparative information provided in these interim Consolidated Financial Statements represent the financial position, results of operations and cash flows of the businesses transferred to Cenovus on a carve-out basis. Management believes the assumptions underlying the Cenovus Carve-out Consolidated Financial Statements for prior period comparatives are reasonable.

2. BACKGROUND & BASIS OF PRESENTATION (continued)

However, these comparative amounts may not reflect Cenovus's financial position, results of operations, and cash flows had Cenovus been a stand-alone company during the comparative periods presented. For additional information regarding the carve-out process, readers should refer to Cenovus's annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2009.

3. CHANGE IN REPORTING CURRENCY

Upon the creation of the Company on November 30, 2009 as a result of the Arrangement, Cenovus reported its results in U.S. dollars for the preparation of its December 31, 2009 financial statements as this was the reporting currency used by Encana. Effective January 1, 2010, the Company changed its reporting currency to Canadian dollars. The change in reporting currency is to better reflect the business of Cenovus, and it allows for increased comparability to the Company's peers. In implementing this change, the Company has followed the requirements of the Canadian Institute of Chartered Accountants ("CICA") Emerging Issues Committee ("EIC") Abstract 130 ("EIC-130"), "Translation Method When the Reporting Currency Differs from the Measurement Currency or there is a Change in the Reporting Currency."

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

4. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

Business Combinations

On January 1, 2010, Cenovus early adopted CICA Handbook Section 1582, "Business Combinations," which replaces CICA Handbook Section 1581 of the same name. The new standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the Statement of Earnings. The adoption of this standard did not impact the Company's interim Consolidated Financial Statements for the period ended September 30, 2010. However, the adoption of this new standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements and Non-controlling Interests

In conjunction with the early adoption of CICA Handbook Section 1582, the Company was also required to early adopt CICA Handbook Sections 1601, "Consolidated Financial Statements" and 1602, "Non-controlling Interests" effective January 1, 2010. These sections replace the former consolidated financial statement standard, CICA Handbook Section 1600, "Consolidated Financial Statements." Section 1601 establishes the requirements for the preparation of the consolidated financial statements and Section 1602 establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 requires a non-controlling interest to be classified as a separate component of equity. In addition, net earnings, and components of other comprehensive income are attributed to both the parent and non-controlling interest. The early adoption of these standards did not have a material impact on the Company's interim Consolidated Financial Statements for the period ended September 30, 2010. These standards along with CICA Handbook Section 1582 above are converged with International Financial Reporting Standards ("IFRS") (see Note 5).

4. CHANGES IN ACCOUNTING POLICIES AND PRACTICES (continued)

Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2010.

5. RECENT ACCOUNTING PRONOUNCEMENTS

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

6. DIVESTITURES

For the nine months ended September 30, 2010, total proceeds received from the divestiture of assets were $312 million (2009–$1 million). For the three months ended September 30, 2010, total proceeds received from the divestiture of assets were $168 million.

7. INTEREST, NET

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Interest Expense–Long-Term Debt	**58**	47	**173**	144
Interest Expense–Other	**56**	61	**147**	169
Interest Income	**(35)**	(44)	**(110)**	(147)
	79	64	**210**	166

Interest Expense – Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively.

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**(109)**	(173)	**(59)**	(291)
Translation of U.S. dollar Partnership Contribution Receivable issued from Canada	**70**	258	**14**	444
Other	**1**	49	**6**	88
Unrealized Foreign Exchange (Gain) Loss	**(38)**	134	**(39)**	241
Realized Foreign Exchange (Gain) Loss	**14**	(14)	**16**	(30)
	(24)	120	**(23)**	211

9. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Current				
Canada	**30**	149	**60**	406
United States	**-**	(12)	**-**	(20)
Total Current Tax	**30**	137	**60**	386
Future	**33**	(90)	**129**	(195)
	63	47	**189**	191

10. INVENTORIES

As at	**September 30, 2010**	December 31, 2009
Product		
Upstream Canada	**225**	267
Downstream Refining	**615**	589
Parts and Supplies	**22**	19
	862	875

11. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In relation to the creation and activities of the integrated oil business venture with ConocoPhillips, the following represent Cenovus's 50 percent share of amounts receivable and payable:

Partnership Contribution Receivable

As at	**September 30, 2010**	December 31, 2009
Current	**353**	345
Long-term	**2,313**	2,621
	2,666	2,966

Partnership Contribution Payable

As at	**September 30, 2010**	December 31, 2009
Current	**350**	340
Long-term	**2,344**	2,650
	2,694	2,990

In addition to the Partnership Contribution Receivable and Payable, other assets and other liabilities include equal amounts for interest bearing member loans, with no fixed repayment terms, related to the funding of refining operating and capital requirements. At September 30, 2010 these amounts were $283 million (December 31, 2009–$183 million).

12. LONG-TERM DEBT

As at	September 30, 2010	December 31, 2009
Canadian Dollar Denominated Debt		
Revolving term debt*	**22**	32
U.S. Dollar Denominated Debt		
Revolving term debt*	**-**	26
Unsecured notes	**3,604**	3,663
	3,604	3,689
Total Debt Principal	**3,626**	3,721
Debt Discounts and Transaction Costs	**(52)**	(65)
	3,574	3,656

* Revolving term debt includes commercial paper, bankers' acceptances, Libor loans, prime rate loans and U.S. base rate loans.

In September 2010, Cenovus renegotiated its $2.5 billion unsecured credit facility and combined the two existing tranches into a single tranche with a maturity of November 30, 2014.

Included in Cenovus's long-term debt obligations of $3,574 million at September 30, 2010, are $22 million in principal obligations related to the issuance of commercial paper. These amounts are fully backstopped by the Company's 4-year revolving syndicated credit facility, which expires in November 2014 and has no repayment requirements within the next year.

In conjunction with the Arrangement, on September 18, 2009 Cenovus completed a private offering of senior unsecured notes of an aggregate principal amount of US$3,500 million. The notes were disclosed on Cenovus's Consolidated Balance Sheet as a long term liability, net of financing costs as at September 30, 2009. The net proceeds of $3,718 million were placed into an escrow account held by the escrow agent, The Bank of New York Mellon, pending the completion of the Arrangement. Cenovus placed an additional $162 million into the escrow account so that the total escrowed funds of $3,880 million would be sufficient to pay the special mandatory redemption price for the notes if the Arrangement did not proceed. The cash in escrow was disclosed as Restricted Cash on the Consolidated Balance Sheet as at September 30, 2009. On November 30, 2009 the funds were released from escrow and the notes became the direct, unsecured obligations of Cenovus.

At September 30, 2010, Cenovus is in compliance with all of the terms of its debt agreements.

Cenovus has in place 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 September 30, 2010, no medium term notes have been issued. The shelf prospectus expires in July 2012.

Cenovus has in place a U.S. base shelf prospectus for unsecured notes in the amount of US$1.5 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. At September 30, 2010, no notes have been issued. The shelf prospectus expires in August 2012.

13. ASSET RETIREMENT OBLIGATION

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

As at	September 30, 2010	December 31, 2009
Asset Retirement Obligation, Beginning of Year	**1,147**	793
Liabilities Incurred	**31**	6
Liabilities Settled	**(22)**	(38)
Liabilities Divested	**(83)**	(10)
Change in Estimated Future Cash Outflows	**(5)**	357
Accretion Expense	**58**	45
Foreign Currency Translation	**(1)**	(6)
Asset Retirement Obligation, End of Period	**1,125**	1,147

14. SHARE CAPITAL

Authorized

Cenovus is authorized to issue an unlimited number of Common Shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares.

Issued and Outstanding

As at September 30, 2010	Number of Common Shares (millions)	Amount
Outstanding, Beginning of Year	**751.3**	**3,681**
Common Shares Issued under Option Plans	**0.7**	**12**
Outstanding, End of Period	**752.0**	**3,693**

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

At September 30, 2010, there were 24 million Common Shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at September 30, 2010.

On April 21, 2010, the Company established a dividend reinvestment plan ("DRIP"). Under the DRIP, holders of Common Shares may reinvest all or a portion of the cash dividends payable on their Common Shares in additional Common Shares. At the discretion of the Company, the additional Common Shares may be issued from treasury at an average market price or purchased on the market at prevailing market rates. For the purpose of the Common Shares issued from treasury, the average market price will be calculated as 100 percent of the volume weighted average price of the Common Shares traded on the TSX or the NYSE during the last five trading days preceding the relevant dividend payment date. At the discretion of the Board of Directors of Cenovus, the treasury shares may be issued at a discount to the average market price but the discount may not exceed five percent. As at September 30, 2010, there was approximately a two percent participation rate in the Plan and additional Common Shares were purchased on the market to satisfy DRIP requirements.

14. SHARE CAPITAL (continued)

Net Investment

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

Option Plans

Cenovus Employee Stock Option Plan

Cenovus has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on February 17, 2010 or later expire after seven years. In addition, certain stock options granted are performance based. The performance based stock options vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to Cenovus attaining prescribed performance relative to pre-determined key measures. All options issued by the Company have an associated Tandem Share Appreciation Right ("TSAR") attached to them (see Note 16).

Cenovus Replacement Tandem Share Appreciation Rights ("Cenovus Replacement TSARs") Held By Encana Employees

Under the terms of the Arrangement, each original Encana TSAR was replaced with one Encana Replacement TSAR and one Cenovus Replacement TSAR with terms and conditions similar to the original Encana TSAR. Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's employees when these employees exercise a Cenovus Replacement TSAR and therefore, no compensation expense is recognized. No further Cenovus Replacement TSARs will be granted to Encana employees.

Encana employees can choose to exercise the Cenovus Replacement TSAR in exchange for a Cenovus Common Share or for cash. Cenovus has recorded a liability in the Consolidated Balance Sheet for Cenovus Replacement TSARs held by Encana employees using the fair value method, with an offsetting accounts receivable from Encana. The fair value of each Cenovus Replacement TSAR held by Encana employees was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	**1.45%**
Dividend Yield	**2.76%**
Volatility	**26.96%**
Cenovus's Common Share Price	**$29.00**

14. SHARE CAPITAL (continued)

The following tables summarize information related to the Cenovus Replacement TSARs held by Encana employees:

As at September 30, 2010	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**22,945,337**	**10,462,643**	**27.14**
Exercised – SARs	**(2,683,592)**	**(268,564)**	**21.98**
Exercised – Options	**(101,805)**	**(171)**	**19.18**
Forfeited	**(1,322,864)**	**(1,063,559)**	**28.66**
Outstanding, End of Period	**18,837,076**	**9,130,349**	**27.82**
Exercisable, End of Period	**12,355,871**	**4,982,501**	**27.37**

	Outstanding TSARs				Exercisable TSARs		
Range of Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
20.00 to 24.99	**2,850,091**	**-**	**0.40**	**22.95**	**2,836,756**	**-**	**22.94**
25.00 to 29.99	**10,648,997**	**6,274,648**	**2.41**	**26.49**	**6,446,748**	**3,510,820**	**26.62**
30.00 to 34.99	**5,159,838**	**2,855,701**	**2.33**	**32.82**	**2,965,477**	**1,471,681**	**32.76**
35.00 to 39.99	**99,500**	**-**	**2.67**	**37.20**	**59,700**	**-**	**37.20**
40.00 to 44.99	**77,150**	**-**	**2.70**	**42.81**	**46,290**	**-**	**42.81**
45.00 to 49.99	**1,500**	**-**	**2.64**	**45.56**	**900**	**-**	**45.56**
	18,837,076	**9,130,349**	**2.09**	**27.82**	**12,355,871**	**4,982,501**	**27.37**

15. CAPITAL STRUCTURE

Cenovus's capital structure is comprised of Shareholders' Equity plus Long-Term Debt. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent.

As at	**September 30, 2010**	December 31, 2009
Debt	**3,574**	3,656
Shareholders' Equity	**10,159**	9,608
Total Capitalization	**13,733**	13,264
Debt to Capitalization ratio	**26%**	28%

15. CAPITAL STRUCTURE (continued)

Cenovus targets a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at	September 30, 2010	December 31, 2009
Debt	**3,574**	3,656
Net Earnings	**962**	818
Add (deduct):		
Interest, net	**288**	244
Income tax expense	**342**	344
Depreciation, depletion and amortization	**1,338**	1,527
Accretion of asset retirement obligation	**69**	45
Foreign exchange (gain) loss, net	**70**	304
(Gain) loss on disposal of assets	**9**	-
Other (income) loss, net	**(3)**	(2)
Adjusted EBITDA	**3,075**	3,280
Debt to Adjusted EBITDA*	**1.2x**	1.1x

* Calculated on a trailing 12-month basis

It is Cenovus's intention to maintain an investment grade credit rating to ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facility or repay existing debt.

Cenovus's capital structure, objectives and targets have remained unchanged over the periods presented. At September 30, 2010, Cenovus is in compliance with all of the terms of its debt agreements.

16. COMPENSATION PLANS

Cenovus has in place programs whereby employees may be granted the following share-based long-term incentives:

- **Tandem Share Appreciation Rights**
  Tandem Share Appreciation Rights ("TSARs") are options to purchase Common Shares issued under the Cenovus Employee Stock Option Plan whereby the option holder has the right to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSARs vest and expire under the same terms and conditions as the underlying option. Certain of the TSARs ("Performance TSARs") have an additional vesting requirement which is subject to the achievement of prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited.

- **Share Appreciation Rights**
  Share Appreciation Rights ("SARs") entitle the employee to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the right. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the original grant date. Certain of the SARs ("Performance SARs") have an additional vesting requirement which is subject to the achievement of prescribed performance relative to key pre-determined measures. Performance SARs that do not vest when eligible are forfeited.

16. COMPENSATION PLANS (continued)

In accordance with the Arrangement described in Note 2, each Cenovus employee holding an original Encana long-term incentive unit of the same nature disposed of their right to Cenovus in exchange for a Cenovus Replacement Unit and to Encana for an Encana Replacement Unit. The terms and conditions of the Cenovus and Encana Replacement Units are similar to the terms and conditions of the original Encana Unit. The original exercise price of the Encana Unit was apportioned to the Cenovus and Encana Replacement Units based on the one day volume weighted average trading price of Cenovus's Common Share price relative to that of Encana's Common Share price on the TSX on December 2, 2009. Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees for the Encana Replacement Units they hold. No further Encana Replacement Units will be granted to Cenovus employees.

All of these share-based long-term incentive programs have similar vesting provisions as the Cenovus stock option plan. Cenovus Units and Cenovus Replacement Units are measured against the Cenovus Common Share price and Encana Replacement Units are measured against the Encana Common Share price.

The Company has recorded a liability in the Consolidated Balance Sheet for Encana Replacement Units held by the Company's employees using the fair value method. The fair value of each Encana Replacement Unit granted is estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2010
Risk Free Rate	1.45%
Dividend Yield	2.84%
Volatility	24.53%
Encana's Common Share Price	$30.00

A) Tandem Share Appreciation Rights

The following tables summarize the information related to the TSARs held by Cenovus employees:

As at September 30, 2010	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
TSARs – Outstanding, Beginning of Year	16,454,727	8,053,074	27.52
Granted	5,890,885	-	26.44
Exercised – SARs	(823,546)	(59,846)	20.37
Exercised – Options	(354,584)	(44,153)	22.18
Forfeited	(904,598)	(714,368)	28.57
Outstanding, End of Period	20,262,884	7,234,707	27.55
Exercisable, End of Period	8,751,330	3,682,713	27.61

	Outstanding TSARs				Exercisable TSARs		
Range of Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
20.00 to 24.99	1,979,250	-	0.45	22.95	1,940,895	-	22.94
25.00 to 29.99	13,942,223	4,817,156	4.17	26.44	4,384,779	2,433,732	26.59
30.00 to 34.99	4,146,861	2,417,551	2.38	32.88	2,308,926	1,248,981	32.86
35.00 to 39.99	121,850	-	2.70	37.17	73,110	-	37.17
40.00 to 44.99	70,700	-	2.71	43.28	42,420	-	43.28
45.00 to 49.99	2,000	-	2.64	45.56	1,200	-	45.56
	20,262,884	7,234,707	3.34	27.55	8,751,330	3,682,713	27.61

For the nine months ended September 30, 2010, Cenovus has recorded $27 million in compensation costs related to the TSARs.

16. COMPENSATION PLANS (continued)

B) Share Appreciation Rights

The following tables summarize the information related to the SARs held by Cenovus employees:

As at September 30, 2010	Total Number of SARs	Performance SARs	Weighted Average Exercise Price ($)
SARs – Outstanding, Beginning of Year	44,657	23,932	29.38
Forfeited	(3,271)	(2,646)	29.28
Outstanding, End of Period	41,386	21,286	29.38
Exercisable, End of Period	16,226	8,246	30.42

	Outstanding SARs				Exercisable SARs		
Range of Exercise Price ($)	Total Number of SARs	Performance SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Total Number of SARs	Performance SARs	Weighted Average Exercise Price ($)
25.00 to 29.99	24,128	10,528	3.39	26.83	6,768	2,688	26.86
30.00 to 34.99	17,258	10,758	2.37	32.96	9,458	5,558	32.96
	41,386	21,286	2.96	29.38	16,226	8,246	30.42

For the nine months ended September 30, 2010, Cenovus has not recorded any significant compensation costs related to the SARs.

C) Encana Replacement Tandem Share Appreciation Rights

The following tables summarize information related to the Encana Replacement TSARs held by Cenovus employees:

As at September 30, 2010	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
Replacement TSARs – Outstanding, Beginning of Year	16,356,660	8,051,692	30.46
Exercised – SARs	(1,356,607)	(139,003)	24.00
Exercised – Options	(92,670)	(45)	21.39
Forfeited	(836,954)	(716,700)	31.76
Outstanding, End of Period	14,070,429	7,195,944	31.06
Exercisable, End of Period	8,443,335	3,643,950	30.68

	Outstanding Encana Replacement TSARs				Exercisable Encana Replacement TSARs		
Range of Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price ($)
20.00 to 24.99	7,650	-	3.01	23.05	2,050	-	23.11
25.00 to 29.99	9,499,003	4,778,393	2.23	28.49	5,826,224	2,394,969	28.16
30.00 to 34.99	365,870	-	1.77	32.44	291,150	-	32.45
35.00 to 39.99	4,052,006	2,417,551	2.38	36.47	2,236,371	1,248,981	36.47
40.00 to 44.99	74,200	-	2.75	42.28	44,520	-	42.28
45.00 to 49.99	69,700	-	2.71	47.92	41,820	-	47.92
50.00 to 54.99	2,000	-	2.64	50.39	1,200	-	50.39
	14,070,429	7,195,944	2.27	31.06	8,443,335	3,643,950	30.68

For the nine months ended September 30, 2010, the Company has recorded a reduction of compensation costs of $28 million related to the Encana Replacement TSARs.

16. COMPENSATION PLANS (continued)

D) Encana Replacement Share Appreciation Rights

The following tables summarize information related to the Encana Replacement SARs held by Cenovus employees:

As at September 30, 2010	Total Number of SARs	Performance SARs	Weighted Average Exercise Price ($)
Encana Replacement SARs – Outstanding, Beginning of Year	**44,657**	**23,932**	**32.48**
Forfeited	**(3,271)**	**(2,646)**	**32.37**
Outstanding, End of Period	**41,386**	**21,286**	**32.49**
Exercisable, End of Period	**16,226**	**8,246**	**33.63**

	Outstanding Encana Replacement SARs				Exercisable Encana Replacement SARs		
Range of Exercise Price ($)	Total Number of SARs	Performance SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($)	Total Number of SARs	Performance SARs	Weighted Average Exercise Price ($)
25.00 to 29.99	**21,128**	**10,528**	**3.34**	**29.25**	**5,868**	**2,688**	**29.26**
30.00 to 34.99	**3,000**	**-**	**3.71**	**32.55**	**900**	**-**	**32.55**
35.00 to 39.99	**17,258**	**10,758**	**2.37**	**36.44**	**9,458**	**5,558**	**36.44**
	41,386	**21,286**	**2.96**	**32.49**	**16,226**	**8,246**	**33.63**

For the nine months ended September 30, 2010, the Company has not recorded any significant compensation costs related to the Encana Replacement SARs.

E) Deferred Share Units

Cenovus has in place a program whereby directors, officers and employees may receive Deferred Share Units ("DSUs"), which are equivalent in value to a Common Share of the Company. Commencing in 2009, employees had the option to convert either 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, can be redeemed in accordance with terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

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

The following table summarizes information related to the DSUs held by Cenovus directors, officers and employees:

As at September 30, 2010	Outstanding DSUs
Outstanding, Beginning of Year	**768,103**
Granted	**63,559**
Granted from Annual Bonus Awards	**81,117**
Units in Lieu of Dividends	**20,018**
Outstanding, End of Period	**932,797**

For the nine months ended September 30, 2010, the Company has recorded $5 million in compensation costs related to DSUs.

16. COMPENSATION PLANS (continued)

F) Performance Share Units

In 2010, the Company granted Performance Share Units ("PSUs") to certain employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a Common Share of Cenovus or a cash payment equal to the value of a Cenovus Common Share. The number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three, multiplied by a performance multiplier for each year. The multiplier is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The following table summarizes information related to the PSUs held by Cenovus employees:

As at September 30, 2010	Outstanding PSUs
Outstanding, Beginning of Year	-
Granted	1,251,995
Forfeited	(25,376)
Units in Lieu of Dividends	27,359
Outstanding, End of Period	1,253,978

For the nine months ended September 30, 2010, the Company has recorded $13 million in compensation costs related to the PSUs.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the Partnership Contribution Receivable and Payable and member loans, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the Partnership Contribution Receivable and Payable and member loans approximate their carrying amount due to the specific non-tradeable nature of these instruments in relation to the creation of the integrated oil business venture.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on market information.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

The fair value of financial assets and liabilities, including current portions thereof were as follows:

As at	September 30, 2010		December 31, 2009	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading:				
Cash and cash equivalents	**464**	**464**	155	155
Risk management assets	**341**	**341**	61	61
Loans and Receivables:				
Accounts receivable and accrued revenues	**1,051**	**1,051**	978	978
Partnership Contribution Receivable	**2,666**	**2,666**	2,966	2,966
Member loans receivable	**283**	**283**	183	183
Financial Liabilities				
Held-for-trading:				
Risk management liabilities	**33**	**33**	74	74
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**1,692**	**1,692**	1,574	1,574
Long-term debt	**3,574**	**4,227**	3,656	3,964
Partnership Contribution Payable	**2,694**	**2,694**	2,990	2,990
Member loans payable	**283**	**283**	183	183

B) Risk Management Assets and Liabilities

For comparative purposes, under the terms of the Arrangement, the risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

Net Risk Management Position

As at	September 30, 2010	December 31, 2009
Risk Management		
Current asset	**262**	60
Long-term asset	**79**	1
	341	61
Risk Management		
Current liability	**22**	70
Long-term liability	**11**	4
	33	74
Net Risk Management Asset (Liability)	**308**	(13)

Of the $308 million net risk management asset balance at September 30, 2010, an asset of $76 million relates to the contract with Encana.

Summary of Unrealized Risk Management Positions

As at	September 30, 2010			December 31, 2009		
	Risk Management			Risk Management		
	Asset	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Natural Gas	**319**	**-**	**319**	53	-	53
Crude Oil	**22**	**20**	**2**	8	66	(58)
Power	**-**	**13**	**(13)**	-	8	(8)
Total Fair Value	**341**	**33**	**308**	61	74	(13)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	**September 30, 2010**	December 31, 2009
Prices actively quoted	**316**	6
Prices sourced from observable data or market corroboration	**(8)**	(19)
Total Fair Value	**308**	(13)

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Net Fair Value of Commodity Price Positions at September 30, 2010

As at September 30, 2010	Notional Volumes	Term	Average Price	**Fair Value**
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	29,100 bbls/d	2010	US$78.91/bbl	**(6)**
WTI NYMEX Fixed Price	5,000 bbls/d	2010	C$89.65/bbl	**2**
WTI NYMEX Fixed Price	22,000 bbls/d	2011	US$85.42/bbl	**5**
WTI NYMEX Fixed Price	23,000 bbls/d	2011	C$88.36/bbl	**3**
Other Financial Positions *				**(2)**
Crude Oil Fair Value Position				**2**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	412 MMcf/d	2010	US$6.28/Mcf	**92**
NYMEX Fixed Price	351 MMcf/d	2011	US$5.82/Mcf	**180**
NYMEX Fixed Price	130 MMcf/d	2012	US$5.96/Mcf	**42**
Basis Contracts **				
Canada		2010		**(1)**
Canada		2011-2013		**6**
Natural Gas Fair Value Position				**319**
Power Purchase Contracts				
Power Fair Value Position				**(13)**

* Other financial positions are part of ongoing operations to market the Company's production.

**Cenovus has entered into swaps to protect against widening natural gas price differentials between production areas in Canada and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss)			
	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Gross Revenues	**86**	336	**195**	988
Less: Royalties	**-**	-	**-**	-
Net Revenues	**86**	336	**195**	988
Operating Expenses and Other	**(1)**	(4)	**6**	(37)
Gain (Loss) on Risk Management	**85**	332	**201**	951

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

	Unrealized Gain (Loss)			
	Three Months Ended		Nine Months Ended	
For the period ended September 30,	**2010**	2009	**2010**	2009
Gross Revenues	**67**	(348)	**328**	(537)
Less: Royalties	**-**	-	**-**	-
Net Revenues	**67**	(348)	**328**	(537)
Operating Expenses and Other	**(5)**	(3)	**(7)**	(25)
Gain (Loss) on Risk Management	**62**	(351)	**321**	(562)

Reconciliation of Unrealized Risk Management Positions from January 1 to September 30,

	2010		2009
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Period	**(13)**		
Change in Fair Value of Contracts in Place at Beginning of Period and Contracts Entered into During the Period	**522**	**522**	389
Fair Value of Contracts Realized During the Period	**(201)**	**(201)**	(951)
Fair Value of Contracts, End of Period	**308**	**321**	(562)

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, Management believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at September 30, 2010 as follows:

	10% Price Increase	**10% Price Decrease**
Natural gas price	**(95)**	**95**
Crude oil price	**(25)**	**25**
Power price	**3**	**(3)**

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative financial instruments for speculative purposes.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its crude oil sales and condensate supply with fixed price swaps.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into swaps to manage the price differentials between these production areas and various sales points.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Power – The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at September 30, 2010, over 95 percent (December 31, 2009–98 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At September 30, 2010, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (December 31, 2009–three counterparties, including Encana) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the Partnership Contribution Receivable and the member loans receivable is the total carrying value. The current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity through the active management of cash and debt. As disclosed in Note 15, Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash flow from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. At September 30, 2010, Cenovus had $2.5 billion available on its committed bank credit facility. In addition, Cenovus has $1.5 billion in unused capacity under its Canadian shelf prospectus and US$1.5 billion in unused capacity under its U.S. shelf prospectus, the availability of which are dependent on market conditions.

Cash outflows relating to financial liabilities are outlined in the table below:

	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	1,692	-	-	-	**1,692**
Risk Management Liabilities	22	11	-	-	**33**
Long-Term Debt*	211	422	1,230	5,508	**7,371**
Partnership Contribution Payable*	503	1,007	1,007	755	**3,272**
Member Loans Payable	-	283	-	-	**283**

* Principal and interest, including current portion

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results. Cenovus's functional currency and reporting currency is Canadian dollars. All amounts are reported in Canadian dollars, unless otherwise indicated.

As disclosed in Note 8, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At September 30, 2010, Cenovus had US$3,500 million in U.S. dollar debt issued from Canada (US$3,525 million at December 31, 2009) and US$2,589 million related to the U.S. dollar Partnership Contribution Receivable (US$2,834 million at December 31, 2009). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $9 million change in foreign exchange (gain) loss at September 30, 2010 (2009–$9 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

For the nine months ended September 30, 2010, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to $nil (2009–$1 million).

18. PER SHARE AMOUNTS

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2010	2009	**2010**	2009
Weighted Average Common Shares Outstanding – Basic	**751.9**	751.2	**751.7**	750.9
Effect of Dilutive Securities	**0.1**	0.2	**0.3**	0.5
Weighted Average Common Shares Outstanding – Diluted	**752.0**	751.4	**752.0**	751.4

Since Cenovus's shares were issued pursuant to the Arrangement with Encana to create the Company, the per share amounts disclosed for the comparative period are based on Encana's Common Shares.

19. CONTINGENCIES

Legal Proceedings

Cenovus is involved in various legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

(C$ millions, except per share amounts)	2010				2009				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Revenues	10,142	3,222	3,318	3,602	11,790	3,103	3,080	2,871	2,736
Less: Royalties	341	107	123	111	273	98	79	53	43
Net Revenues	9,801	3,115	3,195	3,491	11,517	3,005	3,001	2,818	2,693
Operating Cash Flow									
Crude Oil and Natural Gas Liquids									
Foster Creek and Christina Lake	570	179	176	215	663	232	198	162	71
Canadian Plains	805	262	234	309	1,057	289	314	275	179
Natural Gas	828	246	268	314	2,061	412	500	555	594
Other Upstream Operations	22	5	11	6	50	9	27	3	11
	2,225	692	689	844	3,831	942	1,039	995	855
Downstream	(62)	(32)	(24)	(6)	358	12	95	178	73
Operating Cash Flow	2,163	660	665	838	4,189	954	1,134	1,173	928
Cash Flow Information									
Cash from Operating Activities	1,936	645	471	820	3,039	150	1,414	793	682
Deduct (Add back):									
Net change in other assets and liabilities	(41)	(13)	(13)	(15)	(26)	(14)	(3)	(6)	(3)
Net change in non-cash working capital	210	149	(53)	114	220	(71)	493	(146)	(56)
Cash Flow [1]	1,767	509	537	721	2,845	235	924	945	741
Per share - Basic	2.35	0.68	0.71	0.96	3.79	0.31	1.23	1.26	0.99
- Diluted	2.35	0.68	0.71	0.96	3.79	0.31	1.23	1.26	0.99
Operating Earnings [2]	654	159	142	353	1,522	169	427	512	414
Per share - Diluted	0.87	0.21	0.19	0.47	2.03	0.23	0.57	0.68	0.55
Net Earnings	920	223	172	525	818	42	101	160	515
Per share - Basic	1.22	0.30	0.23	0.70	1.09	0.06	0.13	0.21	0.69
- Diluted	1.22	0.30	0.23	0.70	1.09	0.06	0.13	0.21	0.69
Effective Tax Rates using									
Net Earnings	17.0%				29.6%				
Operating Earnings, excluding divestitures	12.0%				25.0%				
Canadian Statutory Rate	28.2%				29.2%				
Foreign Exchange Rates *(US$ per C$1)*									
Average	0.966	0.962	0.973	0.961	0.876	0.947	0.911	0.857	0.803
Period end	0.971	0.971	0.943	0.985	0.956	0.956	0.933	0.860	0.794

(1) 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, both of which are defined on the Consolidated Statement of Cash Flows.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding the after-tax gain/loss on discontinuance, after-tax effect of unrealized mark-to-market accounting gains/losses on derivative instruments, after-tax gains/losses on translation of U.S. dollar denominated Notes issued from Canada, after-tax foreign exchange gains/losses on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

	2010	2009
Financial Metrics (Non-GAAP measures)		
Debt to Capitalization [1]	26%	28%
Debt to Adjusted EBITDA [1]	1.2x	1.1x
Return on Capital Employed [2]	9%	8%
Return on Common Equity [3]	10%	8%

(1) Non-GAAP measure as defined in the Interim Consolidated Financial Statements and Management's Discussion and Analysis
(2) Calculated, on a trailing twelve-month basis, as net earnings before after tax interest divided by average shareholder's equity plus average debt, including current portion
(3) Calculated, on a trailing twelve-month basis, as net earnings divided by average shareholder's equity

Common Share Information	2010				December
	Year to Date	Q3	Q2	Q1	2009
Common Shares Outstanding *(millions)* [1]					
Period end	752.0	752.0	751.8	751.7	751.3
Average - Basic	751.7	751.9	751.7	751.5	751.0
Average - Diluted	752.0	752.0	751.8	751.7	751.4
Price Range *($ per share)*					
TSX - C$					
High	31.00	31.00	30.63	27.84	27.18
Low	24.26	26.19	25.83	24.26	24.68
Close	29.59	29.59	27.40	26.53	26.50
NYSE - US$					
High	30.66	30.12	30.66	26.79	25.70
Low	22.87	24.61	23.84	22.87	23.37
Close	28.77	28.77	25.79	26.21	25.20
Dividends Paid ($ per share) [2]	C$0.60	C$0.20	C$0.20	C$0.20	US$0.20
Share Volume Traded *(millions)*	634.4	188.0	241.9	204.5	83.5

(1) Cenovus Common Shares were issued under the terms of the plan of arrangement with Encana Corporation ("Arrangement") on November 30, 2009 and began trading on December 3, 2009 (TSX) and December 9, 2009 (NYSE).
(2) Dividend paid in December reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flows.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Net Capital Investment *(C$ millions)*	**2010**				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment									
Upstream Canada									
Foster Creek	**168**	**59**	52	57	262	76	62	59	65
Christina Lake	**240**	**93**	84	63	224	66	53	49	56
Canadian Plains	**407**	**166**	102	139	553	115	104	99	235
Other	**47**	**5**	11	31	57	5	4	14	34
	862	**323**	249	290	1,096	262	223	221	390
Downstream Refining	**516**	**146**	168	202	1,032	224	291	265	252
Corporate	**25**	**11**	13	1	34	21	1	2	10
Capital Investment	**1,403**	**480**	430	493	2,162	507	515	488	652
Acquisitions	**51**	**4**	47	-	148	146	1	1	-
Divestitures	**(312)**	**(168)**	(72)	(72)	(367)	(366)	2	(3)	-
Net Acquisition and Divestiture Activity	**(261)**	**(164)**	(25)	(72)	(219)	(220)	3	(2)	-
Net Capital Investment	**1,142**	**316**	405	421	1,943	287	518	486	652

Operating Statistics - Before Royalties

Upstream Production Volumes	**2010**				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*									
Heavy Oil									
Foster Creek	**50,798**	**50,269**	51,010	51,126	37,725	47,017	40,367	34,729	28,554
Christina Lake	**7,660**	**7,838**	7,716	7,420	6,698	7,319	6,305	6,530	6,635
Integrated Oil - Senlac	**-**	**-**	-	-	3,057	2,221	5,080	2,574	2,334
Canadian Plains	**36,170**	**36,090**	35,572	36,856	38,668	37,057	38,989	37,643	41,023
Light and Medium Oil									
Canadian Plains	**33,259**	**32,698**	33,102	33,991	34,484	34,518	34,504	34,609	34,300
Natural Gas Liquids [1]									
Canadian Plains	**1,165**	**1,172**	1,166	1,156	1,206	1,183	1,242	1,184	1,213
Total Crude Oil and Natural Gas Liquids	**129,052**	**128,067**	128,566	130,549	121,838	129,315	126,487	117,269	114,059
Natural Gas (MMcf/d)									
Integrated Oil - Other	**42**	**41**	43	42	50	44	52	54	50
Canadian Plains	**712**	**697**	708	733	787	753	778	802	816
Total Natural Gas Production	**754**	**738**	751	775	837	797	830	856	866

[1] Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of realized financial hedging)*	**2010**				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Foster Creek	**15.6%**	**17.9%**	19.0%	9.7%	2.7%	3.9%	3.0%	1.5%	1.4%
Crude Oil - Christina Lake	**4.1%**	**3.9%**	4.4%	4.0%	2.3%	3.6%	2.9%	1.6%	1.0%
Crude Oil - Pelican Lake/Weyburn	**22.2%**	**20.6%**	23.5%	19.6%	19.4%	22.8%	19.9%	19.2%	15.7%
Crude Oil - Other	**8.5%**	**7.0%**	9.3%	10.9%	7.8%	8.4%	9.0%	6.1%	5.4%
Natural Gas	**2.3%**	**2.4%**	1.7%	2.8%	1.5%	3.9%	0.5%	-0.9%	2.8%
Natural Gas Liquids	**2.1%**	**2.4%**	2.0%	2.1%	1.6%	1.6%	2.1%	1.9%	1.0%

Downstream Refining	**2010**				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations [1]									
Crude oil capacity *(Mbbls/d)*	**452**	**452**	452	452	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**379**	**401**	379	355	394	348	425	404	398
Crude utilization *(%)*	**84%**	**89%**	84%	79%	87%	77%	94%	89%	88%
Refined products *(Mbbls/d)*	**395**	**409**	398	377	417	370	451	428	421

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

Benchmark Prices	**2010**				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices (US$/bbl)									
West Texas Intermediate ("WTI")	**77.69**	**76.21**	78.05	78.88	62.09	76.13	68.24	59.79	43.31
Western Canada Select ("WCS")	**64.76**	**60.56**	63.96	69.84	52.43	64.01	58.06	52.37	34.38
Differential - WTI/WCS	**12.93**	**15.65**	14.09	9.04	9.66	12.12	10.18	7.42	8.93
Condensate - (C5 @ Edmonton)	**80.76**	**74.53**	82.87	84.98	61.35	74.42	65.76	58.07	46.26
Differential - WTI/Condensate (premium)/discount	**(3.07)**	**1.68**	(4.82)	(6.10)	0.74	1.71	2.48	1.72	(2.95)
Refining Margins 3-2-1 Crack Spreads [1] (US$/bbl)									
Chicago	**9.35**	**10.34**	11.60	6.11	8.54	5.00	8.48	10.95	9.75
Midwest Combined (Group 3)	**9.60**	**10.60**	11.38	6.82	8.09	5.52	8.06	9.16	9.62
Natural Gas Prices									
AECO ($/GJ)	**4.09**	**3.52**	3.66	5.08	3.85	4.01	2.87	3.47	5.34
NYMEX (US$/MMBtu)	**4.59**	**4.38**	4.09	5.30	3.99	4.17	3.39	3.50	4.89
Differential - NYMEX/AECO (US$/MMBtu)	**0.43**	**0.78**	0.32	0.19	0.40	0.19	0.67	0.39	0.35

[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.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

(C$, excluding impact of realized financial hedging)

	2010				2009				
	Year to Date	**Q3**	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil - Heavy - Foster Creek *($/bbl)*									
Price [1]	**58.76**	**58.51**	54.75	63.33	55.55	63.60	62.20	54.43	33.44
Royalties	**8.25**	**9.56**	9.38	5.76	1.42	2.31	1.85	0.66	0.22
Transportation and selling	**2.38**	**2.40**	2.40	2.33	2.51	1.71	2.50	3.45	2.69
Operating	**10.60**	**10.35**	10.36	11.11	11.87	10.43	10.85	11.81	15.91
Netback	**37.53**	**36.20**	32.61	44.13	39.75	49.15	47.00	38.51	14.62
Crude Oil - Heavy - Christina Lake *($/bbl)*									
Price [2]	**57.81**	**56.45**	54.99	62.27	53.45	57.07	64.85	57.32	32.44
Royalties	**2.17**	**2.04**	2.19	2.28	1.24	2.04	1.72	0.83	0.23
Transportation and selling	**4.21**	**3.69**	4.52	4.47	3.09	0.96	5.36	2.83	3.38
Operating	**16.27**	**15.94**	16.50	16.41	16.31	18.06	15.31	13.69	18.21
Netback	**35.16**	**34.78**	31.78	39.11	32.81	36.01	42.46	39.97	10.62
Crude Oil - Heavy - Canadian Plains *($/bbl)*									
Price [3]	**62.94**	**58.32**	61.02	69.40	55.00	62.00	63.01	56.09	38.76
Royalties	**12.30**	**9.89**	13.14	13.85	9.23	11.29	11.54	8.62	5.42
Production and mineral taxes	**0.03**	**0.02**	(0.03)	0.09	(0.01)	0.02	(0.01)	0.02	(0.07)
Transportation and selling	**1.69**	**1.91**	1.66	1.51	1.08	0.71	0.99	1.35	1.24
Operating	**12.12**	**12.37**	12.93	11.08	9.28	11.68	7.82	9.49	8.30
Netback	**36.80**	**34.13**	33.32	42.87	35.42	38.30	42.67	36.61	23.87
Crude Oil - Heavy - Total *($/bbl)*									
Price [4]	**60.29**	**58.25**	57.12	65.64	55.14	62.46	62.67	55.55	36.15
Royalties	**9.37**	**9.19**	10.20	8.66	5.20	6.02	6.42	4.85	3.03
Production and mineral taxes	**0.01**	**0.01**	(0.01)	0.04	0.03	0.03	0.05	0.05	(0.04)
Transportation and selling	**2.27**	**2.32**	2.29	2.18	1.90	1.27	2.05	2.39	1.98
Operating	**11.69**	**11.67**	11.86	11.53	11.03	11.45	9.60	11.09	12.19
Netback	**36.95**	**35.06**	32.78	43.23	36.98	43.69	44.55	37.17	18.99
Light and Medium Oil - Canadian Plains *($/bbl)*									
Price	**70.78**	**68.08**	66.43	77.71	62.36	71.25	67.53	63.59	46.57
Royalties	**9.14**	**8.59**	9.46	9.37	6.82	10.88	7.30	5.98	3.02
Production and mineral taxes	**2.37**	**2.20**	2.79	2.12	2.20	1.55	2.20	1.94	3.14
Transportation and selling	**0.94**	**1.07**	0.91	0.85	0.89	0.63	0.74	1.07	1.12
Operating	**12.29**	**12.26**	13.11	11.51	10.18	9.93	9.98	9.83	11.01
Netback	**46.04**	**43.96**	40.16	53.86	42.27	48.26	47.31	44.77	28.28
Crude Oil - Total *($/bbl)*									
Price	**63.06**	**60.86**	59.51	68.87	57.22	64.85	64.00	57.95	39.40
Royalties	**9.31**	**9.03**	10.01	8.85	5.67	7.34	6.66	5.18	3.03
Production and mineral taxes	**0.63**	**0.59**	0.71	0.59	0.65	0.44	0.64	0.62	0.95
Transportation and selling	**1.92**	**1.99**	1.94	1.83	1.61	1.10	1.69	2.00	1.71
Operating	**11.85**	**11.83**	12.18	11.52	10.78	11.04	9.70	10.72	11.82
Netback	**39.35**	**37.42**	34.67	46.08	38.51	44.93	45.31	39.43	21.89
Natural Gas Liquids - Canadian Plains *($/bbl)*									
Price	**60.11**	**54.43**	58.71	67.42	49.08	59.06	49.17	44.65	43.42
Royalties	**1.28**	**1.29**	1.16	1.39	0.81	0.96	1.00	0.82	0.46
Netback	**58.83**	**53.14**	57.55	66.03	48.27	58.10	48.17	43.83	42.96
Total Liquids ($/bbl)									
Price	**63.03**	**60.80**	59.50	68.85	57.14	64.79	63.85	57.81	39.45
Royalties	**9.23**	**8.96**	9.93	8.78	5.62	7.28	6.60	5.14	3.00
Production and mineral taxes	**0.63**	**0.59**	0.71	0.59	0.65	0.44	0.63	0.61	0.94
Transportation and selling	**1.90**	**1.97**	1.94	1.83	1.60	1.09	1.67	1.98	1.69
Operating	**11.74**	**11.72**	12.07	11.42	10.67	10.94	9.61	10.61	11.69
Netback	**39.53**	**37.56**	34.85	46.23	38.60	45.04	45.34	39.47	22.13
Total Natural Gas[5] *($/Mcf)*									
Price	**4.25**	**3.68**	3.78	5.27	4.15	4.17	3.14	3.80	5.47
Royalties	**0.10**	**0.08**	0.07	0.14	0.08	0.16	0.02	0.01	0.15
Production and mineral taxes	**0.02**	**0.03**	(0.04)	0.07	0.05	0.03	0.04	0.07	0.05
Transportation and selling	**0.17**	**0.15**	0.15	0.21	0.15	0.12	0.16	0.16	0.18
Operating	**0.94**	**0.94**	0.94	0.94	0.86	0.81	0.84	0.83	0.94
Netback	**3.02**	**2.48**	2.66	3.91	3.01	3.05	2.08	2.73	4.15
Total ($/BOE)									
Price	**44.39**	**41.49**	41.46	50.16	39.88	44.54	40.43	38.65	35.71
Royalties	**4.94**	**4.73**	5.26	4.81	2.87	4.05	3.22	2.35	1.81
Production and mineral taxes	**0.38**	**0.38**	0.24	0.52	0.46	0.30	0.43	0.52	0.58
Transportation and selling	**1.46**	**1.42**	1.43	1.53	1.24	0.91	1.29	1.41	1.34
Operating[6]	**8.72**	**8.70**	8.93	8.53	7.71	7.85	7.24	7.52	8.27
Netback	**28.89**	**26.26**	25.60	34.77	27.60	31.43	28.25	26.85	23.71

(1) The Foster Creek YTD heavy oil price has been reduced by the cost of condensate purchases ($35.46/bbl) which are blended with the heavy oil.

(2) The Christina Lake YTD heavy oil price has been reduced by the cost of condensate purchases ($36.42/bbl) which are blended with the heavy oil.

(3) The Canadian Plains YTD heavy oil price has been reduced by the cost of condensate purchases of ($14.23/bbl) which are blended with the heavy oil.

(4) The total YTD heavy oil price has been reduced by the cost of condensate purchases of ($26.88/bbl) which are blended with the heavy oil.

(5) Natural gas - Total includes natural gas from Canadian Plains and the Athabasca property.

(6) 2010 year-to-date operating costs include costs related to long-term incentives of $0.03/BOE (2009 - $0.10/BOE).

Impact of Realized Financial Hedging

Liquids *($/bbl)*	**(0.06)**	**1.01**	(0.40)	(0.78)	1.10	(0.05)	(0.01)	1.54	3.29
Natural Gas *($/Mcf)*	**0.94**	**1.09**	1.22	0.53	3.63	2.27	4.41	4.33	3.43
Total *($/BOE)*	**2.77**	**3.77**	3.37	1.20	12.16	6.92	13.77	14.91	13.06

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Cenovus Energy Inc.
421 – 7 Ave SW
PO Box 766
Calgary, AB T2P 0M5
Phone: 403-766-2000
Fax: 403-766-8231

Cenovus Communications & Stakeholder Relations

Investor contacts:

Susan Grey
Director, Investor Relations
403-766-4751
susan.grey@cenovus.com

James Fann
Analyst, Investor Relations
403-766-6700
james.fann@cenovus.com

Media contacts:

Rhona DelFrari
Manager, Media Relations
403-766-4740
rhona.delfrari@cenovus.com

Reg Curren
Advisor, Media Relations
403-766-2004
reg.curren@cenovus.com