Management's Discussion and Analysis
For the Period Ended September 30, 2012

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated October 24, 2012, should be read with our unaudited interim Consolidated Financial Statements and accompanying notes for the period ended September 30, 2012 ("interim Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2011 ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory.

Management is responsible for preparing the MD&A. The interim MD&A is approved by the Audit Committee of the Cenovus Board of Directors (the "Board"). 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 International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

WHERE TO FIND:

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On September 30, 2012, we had a market capitalization of approximately $26 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids in Canada with refining operations in the United States ("U.S."). Our average crude oil and natural gas liquids ("Crude Oil") production in the nine months ended September 30, 2012 was in excess of 161,000 barrels per day and our average natural gas production was in excess of 600 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties, which we operate and have a 50 percent ownership interest in, are located in the Athabasca Region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca Region is our wholly owned Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta, which comprise a mix of predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In addition to our upstream assets, we have 50 percent ownership in two refineries located in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to mitigate the volatility associated with North American commodity price movements.

Our operational focus is to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Alberta and Saskatchewan, and to continue the assessment and development of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil 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 innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

Our strategy includes the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic test wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects that we expect to develop in this area include Narrows Lake, Grand Rapids and Telephone Lake.

In May 2012, we received regulatory approval for our approximately 50 percent owned Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day and be developed in three phases. We are currently working with our partner on project sanctioning and anticipate first production in 2017.

At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and Environmental Impact Assessment ("EIA") for a commercial SAGD operation. The proposed project is expected to have a gross production capacity of 180,000 barrels per day.

Our 100 percent owned Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA. The Telephone Lake project is expected to have an initial gross production capacity of 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands and tight oil opportunities. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016, we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in southern Saskatchewan and Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of balance sheet capacity.

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by Phillips 66, an unrelated U.S. public company, enable us to mitigate the effects of commodity price cycles by processing Canadian heavy oil and producing refined products that are generally tied to tidewater prices, thus economically integrating our oil sands production. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful and growing dividends as part of delivering a strong total shareholder return over the long-term.

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

- **Conventional**, which includes the development and production of conventional Crude Oil and natural gas in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

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

OVERVIEW OF THE THIRD QUARTER OF 2012

Cenovus delivered solid performance in the third quarter of 2012, led by very strong oil sands production and solid results from our refining operations. Christina Lake phase D came on production in late July and as a result, production achieved a new single day high of over 87,000 barrels per day gross, well on its way to reaching gross nameplate capacity of 98,000 barrels per day. Foster Creek production averaged above nameplate capacity for the quarter. Refining operations produced 463,000 barrels per day of refined products during the quarter, an increase of 37,000 barrels per day.

OPERATIONAL RESULTS

Our Crude Oil production averaged 171,350 barrels per day, an increase of 28 percent from 2011. Christina Lake production in the month of September averaged almost 73,000 barrels per day gross, due to strong well performance from phase C and the ramp up of production from phase D. In the third quarter, Foster Creek averaged over 126,000 barrels per day gross, five percent above the nameplate capacity of 120,000 barrels per day due to plant optimization.

Within our Conventional segment, Alberta Crude Oil production averaged 29,833 barrels per day during the quarter, 10 percent higher than in 2011 as a result of our successful drilling programs and effectively managing natural declines. Total Crude Oil production in Saskatchewan was 22,352 barrels per day, an increase of 13 percent due to higher production from our Lower Shaunavon and Bakken areas. In the current quarter, Lower Shaunavon and Bakken Crude Oil production averaged 6,252 barrels per day, an increase of 56 percent from the third quarter of 2011.

Our refining operations produced 463,000 barrels per day of refined products during the quarter, an increase of 37,000 barrels per day primarily due to higher heavy crude oil processing capability as a result of the start-up of the coker from the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery in the fourth quarter of 2011.

Significant operational results in the third quarter of 2012 compared to 2011 include:

- Christina Lake setting a new single day gross production high of over 87,000 barrels per day;
- Christina Lake production averaging 32,380 barrels per day, more than a threefold increase due to the start of phases C and D in the third quarters of 2011 and 2012, respectively;
- Foster Creek production averaging 63,245 barrels per day, an increase of 12 percent due to plant optimization;
- Pelican Lake production averaging 23,539 barrels per day, an increase of 16 percent from the third quarter of 2011, as a result of our infill and polymer flood programs;
- Conventional Crude Oil production increasing 12 percent to 52,186 barrels per day due to successful drilling programs and fewer weather and access issues;
- Natural gas production declining 12 percent to 577 MMcf per day primarily due to expected natural declines and the divestiture of a non-core property early in the first quarter of 2012; and
- Refining operations processing an average of 463,000 barrels per day of crude oil compared with 426,000 barrels per day last year, including 210,000 barrels per day of Canadian heavy crude oil.

FINANCIAL RESULTS

Our third quarter financial results benefited from very strong crude oil production and continued high refining margins. Total operating cash flow reached $1.3 billion, while operating earnings for the quarter were $432 million. We also completed a US$1.25 billion public offering of senior unsecured notes in August.

The financial highlights for the third quarter of 2012 compared to 2011 include:

- Revenues increasing $482 million or 12 percent as a result of:
    - Refining and Marketing revenues rising $375 million due primarily to higher refinery output;
    - Crude Oil sales volumes increasing 27 percent; and
    - Increased condensate volumes used for blending partially offset by lower condensate prices.

  Partially offsetting these increases in revenues were:
    - Crude oil average sales prices (excluding financial hedging) decreasing three percent; and
    - Natural gas revenues decreasing $102 million due to declining production and lower average sales prices.
- Operating cash flow of $1,310 million, increasing $365 million due to:
    - Operating cash flow from upstream operations of $783 million, an improvement of $76 million due to higher Crude Oil volumes, despite lower realized prices, which was partially offset by lower natural gas prices and volumes;
    - Operating cash flow of $527 million from our Refining and Marketing segment, increasing $289 million. The continuation of high market crack spreads, the ability to process significantly higher volumes of heavy crude oil subsequent to the coker start-up of the CORE project at the Wood River Refinery and favourable discounts on inland crude feedstock resulted in very strong quarterly refining margins;
- Total cash flow of $1,117 million, increasing 41 percent primarily as a result of higher operating cash flow from our refining operations and Crude Oil due to higher production, offset by lower operating cash flow from natural gas operations as a result of lower sales prices and volumes;
- Operating earnings of $432 million, increasing $129 million, primarily due to higher operating cash flow partially offset by:
    - Increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates;
    - Increased general and administrative costs due to higher long-term incentive costs compared to a recovery of long-term incentive costs in the third quarter of 2011; and
    - Higher income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures) from increased operating cash flow from upstream and refining operations;
- Capital investment of $830 million focusing on the expansion of our producing oil sands operations and the development of tight oil opportunities in southern Alberta and Saskatchewan;
- Our conventional natural gas operations generating $111 million of operating cash flow in excess of related capital investment, used to partially fund the future development of our crude oil projects;
- Completing a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion; and
- Paying a quarterly dividend of $0.22 per share (2011 – $0.20 per share).

OUR BUSINESS ENVIRONMENT

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

Selected Benchmark Prices and Exchange Rates [1]

	Nine Months Ended September 30,		Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2012	2011	**2012**	2012	2012	2011	2011	2011	2011	2010	2010
Crude Oil Prices *(US$/bbl)*											
Brent Futures (ICE)											
Average	**112.20**	111.54	**109.42**	108.76	118.45	109.02	112.09	116.99	105.52	87.45	76.96
End of period	**112.39**	102.76	**112.39**	97.80	122.88	107.38	102.76	112.48	117.36	94.75	82.31
West Texas Intermediate (WTI)											
Average	**96.16**	95.47	**92.20**	93.35	103.03	94.06	89.54	102.34	94.60	85.24	76.21
End of period	**92.19**	79.20	**92.19**	84.96	103.02	98.83	79.20	95.42	106.72	91.38	79.97
Average Differential Brent Futures (ICE)-WTI	**16.04**	16.07	**17.22**	15.41	15.42	14.96	22.55	14.65	10.92	2.21	0.75
Western Canadian Select (WCS)											
Average	**74.16**	76.10	**70.48**	70.48	81.61	83.58	71.92	84.70	71.74	67.12	60.56
End of period	**82.26**	69.38	**82.26**	58.34	79.52	84.37	69.38	75.32	91.37	72.87	64.97
Average Differential WTI-WCS	**22.00**	19.37	**21.72**	22.87	21.42	10.48	17.62	17.64	22.86	18.12	15.65
Condensate (C5 @ Edmonton) Average	**101.83**	104.22	**96.12**	99.32	110.16	108.74	101.48	112.33	98.90	85.24	74.53
Average Differential WTI-Condensate (premium)/discount	**(5.67)**	(8.75)	**(3.92)**	(5.97)	(7.13)	(14.68)	(11.94)	(9.99)	(4.30)	-	1.68
Refining Margin 3-2-1 Average Crack Spreads [2] *(US$/bbl)*											
Chicago	**27.61**	26.32	**35.64**	28.20	19.00	19.23	33.35	29.00	16.62	9.25	10.34
Midwest Combined (Group 3)	**28.59**	26.76	**35.99**	28.28	21.50	20.75	34.04	27.19	19.04	9.12	10.60
Natural Gas Average Prices											
AECO *($/GJ)*	**2.07**	3.55	**2.08**	1.74	2.39	3.29	3.53	3.54	3.58	3.39	3.52
NYMEX *(US$/MMBtu)*	**2.59**	4.21	**2.81**	2.22	2.74	3.55	4.19	4.31	4.11	3.80	4.38
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.41**	0.35	**0.61**	0.39	0.21	0.17	0.34	0.42	0.29	0.28	0.78
U.S./Canadian Dollar Exchange Rate											
Average	**0.998**	1.023	**1.005**	0.990	0.999	0.978	1.020	1.033	1.015	0.987	0.962

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

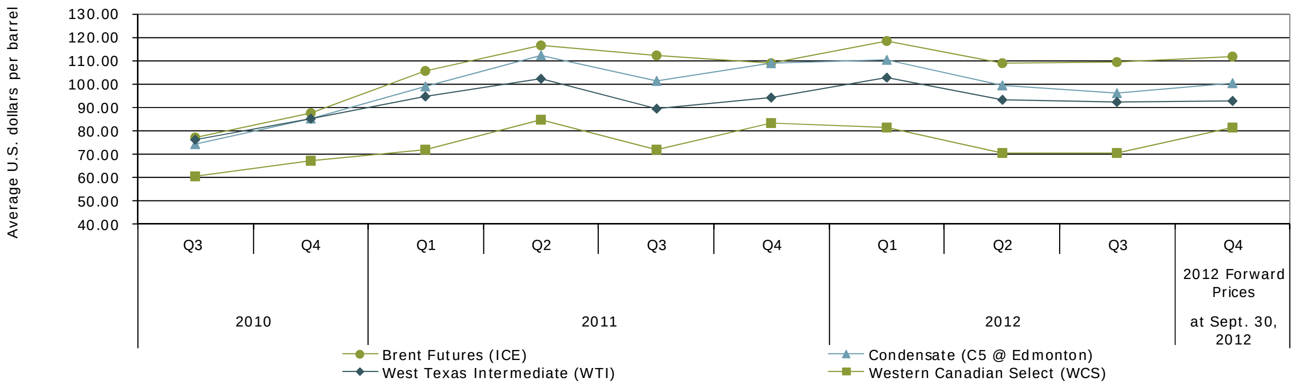
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel, and reflects the current month WTI price as the crude oil feedstock price.

Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and is also a better indicator than WTI of changes in inland refined product prices which are tied to global markets. The average price of Brent crude recovered through the quarter from its sharp drop in May as concerns eased over European sovereign debt issues and its potential effects on Chinese and U.S. economic growth. Although the September 30 closing price rose US$14.59 per barrel from June 30, the average price of Brent crude increased by less than a dollar during the third quarter.

WTI is an important benchmark for Canadian crude oil since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. WTI has been trading at a significant discount to Brent prices for most of the past two years as inland supply growth has strained the capacity of takeaway transportation and inland refineries. These discounts widened in the third quarter, despite additional transportation capacity provided by reversing the Seaway pipeline to flow out of the U.S. Midwest. Although Brent prices increased, the widening Brent-WTI differential resulted in a small drop in average WTI prices during the third quarter compared to the second quarter.

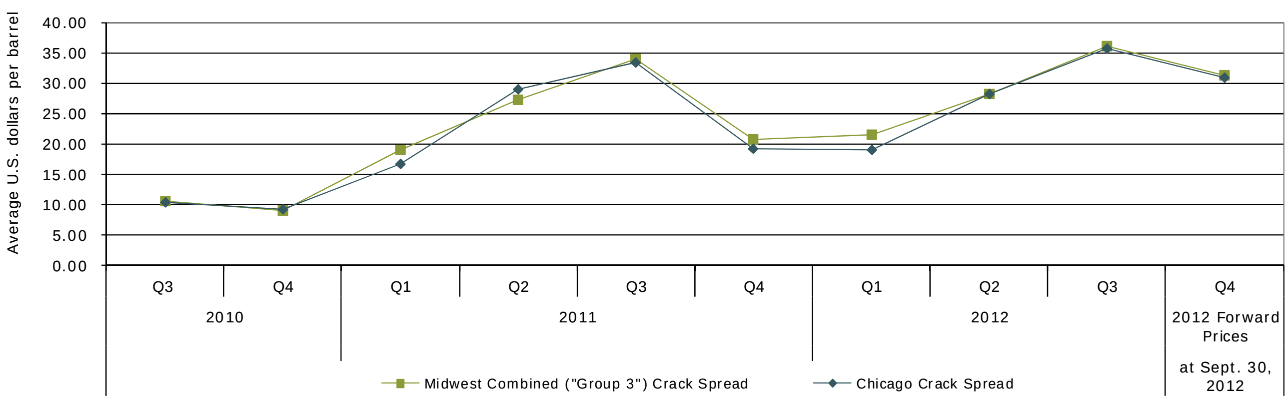
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark, WTI. The WTI-WCS average differential narrowed slightly in the third quarter of 2012 from the second quarter, primarily due to supply outages and increased availability of rail capacity. This offset the continued growth of tight oil and new oil sands capacity entering the market.



Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. Condensate differentials at Edmonton weakened in the third quarter by US$2.05 per barrel compared to the second quarter and by US$8.02 per barrel compared to the same period last year due largely to the continued strong growth in North American condensate supply, mostly from the Eagleford basin in Texas.

<u>Refining 3-2-1 Crack Spread Benchmarks</u>

The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices. Average crack spreads in the U.S. inland Chicago and Group 3 markets in the third quarter of 2012 increased from already strong second quarter levels due to increased inland crude oil discounts, refinery closures and above normal refinery outages.



Benchmark crack spreads are a simplified view of the market based on last-in, first-out accounting, and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and purchased product costs based on first-in, first-out accounting.

<u>Other Benchmarks</u>

Natural gas prices in the third quarter of 2012 strengthened for the first time in over a year from very low second quarter levels due to a continued sharp reduction in storage surpluses from previous record levels as low prices and hot weather stimulated demand. Lower storage balances all but removed the risk of end-of-summer storage congestion. This allowed some firming of prices, though was restricted by the need to maintain significant fuel switching from coal to gas-fired electric generation. A continued decline in the gas rig count, now at its lowest level in a dozen years, further contributed to lower gas storage balances. All of these factors have yet to translate into lower production due to continued growth in associated gas produced with liquids, completion of previously drilled wells and increased supply due to ethane being left in the gas stream from ethane infrastructure constraints predominately in the Marcellus basin.

During the third quarter of 2012, the Canadian dollar strengthened slightly relative to the U.S. dollar, but remained close to currency parity. This was due to the same factors which positively affected crude oil and equity markets.

A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar increases our reported results, although a weaker Canadian dollar also increases our current period's refining capital investment.

FINANCIAL INFORMATION

Our financial results are reported in accordance with IFRS. Further information regarding our IFRS accounting policies can be found in the Annual MD&A and notes to our Consolidated Financial Statements for the year ended December 31, 2011 (see Additional Information).

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
	2012	2011	**2012**	2012	2012	2011	2011	2011	2011	2010	2010
Revenues	**13,118**	11,367	**4,340**	4,214	4,564	4,329	3,858	4,009	3,500	3,363	2,962
Operating Cash Flow (1)	**3,473**	2,843	**1,310**	1,078	1,085	1,019	945	1,064	834	815	661
Cash Flow (1)	**2,946**	2,425	**1,117**	925	904	851	793	939	693	645	509
- per share – diluted	**3.88**	3.20	**1.47**	1.22	1.19	1.12	1.05	1.24	0.91	0.85	0.68
Operating Earnings (1)	**1,055**	907	**432**	283	340	332	303	395	209	147	156
- per share – diluted	**1.39**	1.20	**0.57**	0.37	0.45	0.44	0.40	0.52	0.28	0.19	0.21
Net Earnings	**1,111**	1,212	**289**	396	426	266	510	655	47	78	295
- per share – basic	**1.47**	1.61	**0.38**	0.52	0.56	0.35	0.68	0.87	0.06	0.10	0.39
- per share – diluted	**1.46**	1.60	**0.38**	0.52	0.56	0.35	0.67	0.86	0.06	0.10	0.39
Capital Investment (2)	**2,390**	1,820	**830**	660	900	903	631	476	713	701	479
Cash Dividends	**498**	452	**166**	166	166	151	150	151	151	151	150
- per share	**0.66**	0.60	**0.22**	0.22	0.22	0.20	0.20	0.20	0.20	0.20	0.20

(1) Non-GAAP measures defined within this MD&A.
(2) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets and excludes acquisitions and divestitures.

REVENUES VARIANCE

(millions of dollars)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2011	$ 3,858	$ 11,367
Increase (decrease) due to:		
Oil Sands	252	701
Conventional	(54)	(157)
Refining and Marketing	375	1,322
Corporate and Eliminations	(91)	(115)
Revenues for the Periods Ended September 30, 2012	**$ 4,340**	**$ 13,118**

Oil Sands revenues for the third quarter and the nine months ended September 30, 2012 increased primarily due to increased crude oil and condensate volumes, partially offset by decreased average crude oil and condensate prices.

Conventional revenues decreased for the three and nine months ended September 30, 2012 as Crude Oil production increases over 2011 were offset largely by lower natural gas production and natural gas prices.

Revenues generated by the Refining and Marketing segment rose in the three and nine months ended September 30, 2012, as compared to 2011 resulting from continued favourable refined product prices as well as higher throughput levels and refined product output, subsequent to the start-up of the coker at the CORE project in the fourth quarter of 2011. Higher revenues from operational third party sales undertaken by the marketing group also added to higher revenues.

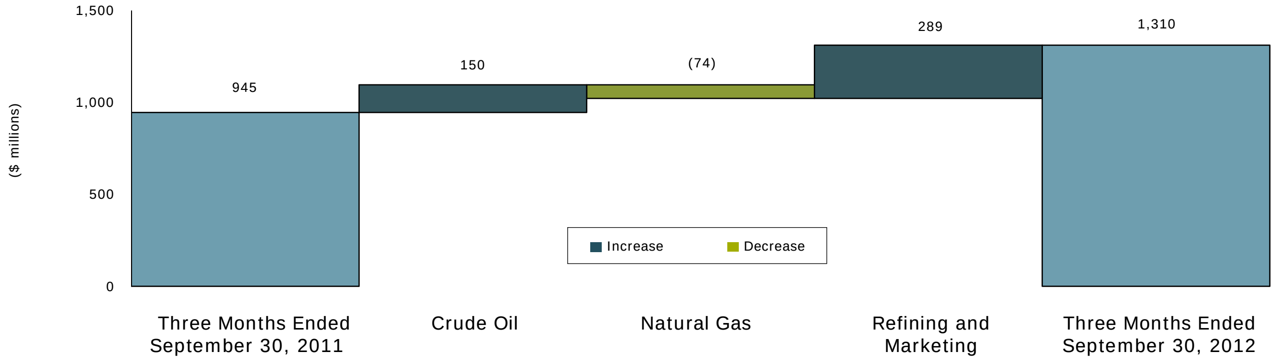
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands				
Crude Oil	**$ 428**	$ 296	**$ 1,223**	$ 867
Natural Gas	**8**	17	**21**	40
Other	**(1)**	-	**(2)**	4
Conventional				
Crude Oil	**227**	209	**722**	635
Natural Gas	**118**	183	**358**	549
Other	**3**	2	**6**	5
Refining and Marketing	**527**	238	**1,145**	743
Operating Cash Flow	**$ 1,310**	$ 945	**$ 3,473**	$ 2,843

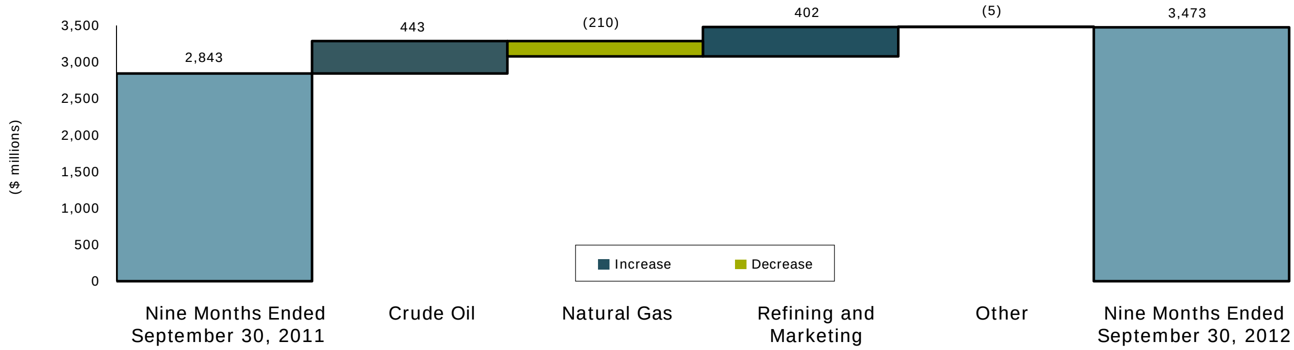
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes, plus realized gains less realized losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.

Operating Cash Flow Variance for the Three Months Ended September 30, 2012 compared to September 30, 2011



Overall, operating cash flow in the third quarter of 2012 rose $365 million due to a $289 million increase from our Refining and Marketing segment and a $76 million increase from our upstream operations. Refining and Marketing operating cash flow rose due to the combination of stronger refining margins and continued high throughput levels and refined product output. Operating cash flow from Crude Oil rose $150 million as a result of higher production volumes despite lower average crude oil sales prices and increased operating costs. The $74 million reduction in operating cash flow from natural gas was mainly due to lower average sales prices combined with decreased production volumes from expected natural declines and the divestiture of a non-core natural gas property in the first quarter of 2012.

Operating Cash Flow Variance for the Nine Months Ended September 30, 2012 compared to September 30, 2011

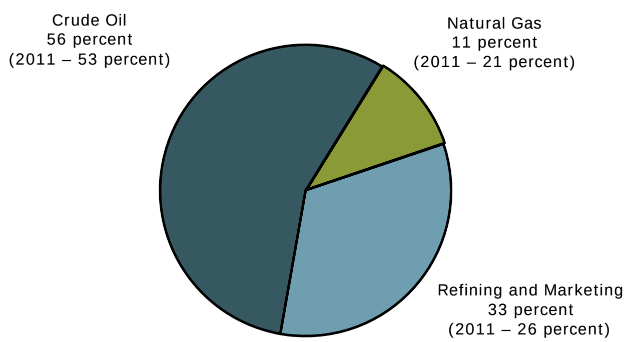


Overall, operating cash flow for the nine months ended September 30, 2012 increased $630 million as operating cash flow from both our upstream operations and Refining and Marketing segment increased from 2011.

The increase in operating cash flow from Crude Oil was primarily due to increased production volumes, partially offset by lower average crude oil sales prices and higher operating costs. Operating cash flow from natural gas declined $210 million as a result of lower average sales prices combined with reduced production volumes from expected natural declines and the divestiture of a non-core natural gas property in the first quarter of 2012. Refining and Marketing operating cash flow rose due to the combination of stronger refining margins resulting from high market cracks and discounted crude oil processed, as well as continued high throughput levels and refined product output.

Operating Cash Flow of $3,473 million for the Nine Months Ended September 30, 2012

Crude Oil generated $1,945 million or 56 percent of our operating cash flow for the nine months ended September 30, 2012. Operating cash flow from our Refining and Marketing segment was $1,145 million or 33 percent of total operating cash flow. Natural gas operating cash flow was $379 million or 11 percent of our total operating cash flow.



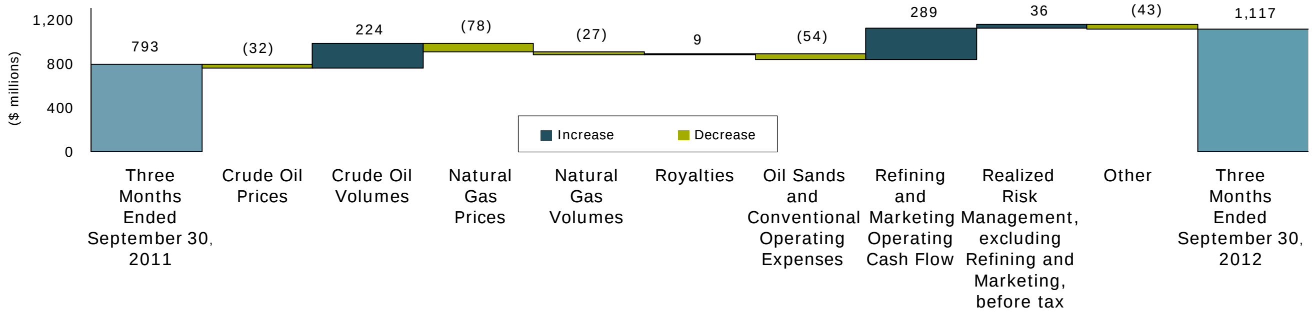
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash From Operating Activities	**$ 1,029**	$ 921	**$ 2,662**	$ 2,321
(Add back) deduct:				
Net change in other assets and liabilities	**(19)**	(17)	**(71)**	(62)
Net change in non-cash working capital	**(69)**	145	**(213)**	(42)
Cash Flow	**$ 1,117**	$ 793	**$ 2,946**	$ 2,425

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 a company's ability to finance its capital programs and meet its financial obligations.

Cash Flow Variance for the Three Months Ended September 30, 2012 compared to September 30, 2011



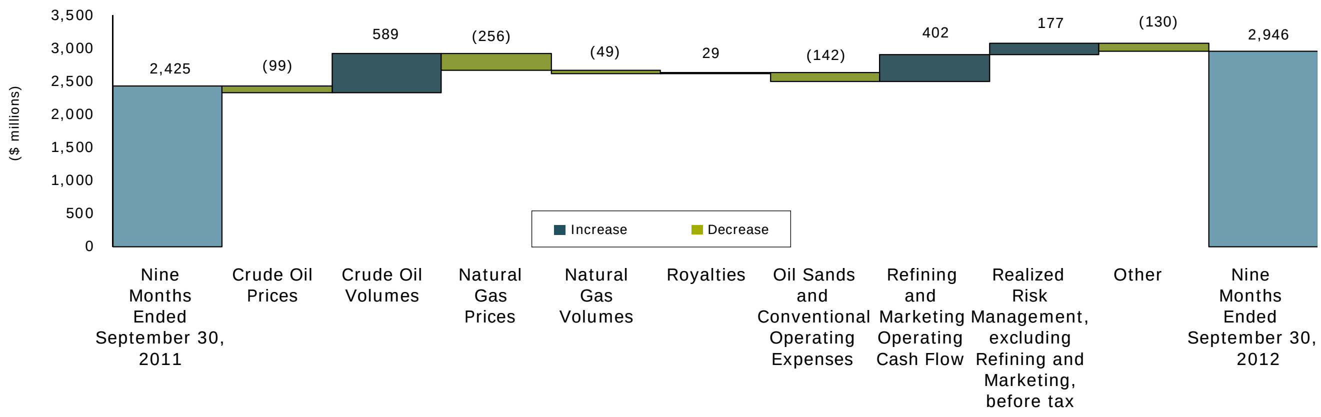
In the third quarter of 2012 our cash flow increased $324 million primarily due to:

- An increase in operating cash flow from Refining and Marketing of $289 million, due to the combination of stronger refining margins and continued high throughput levels and refined product output associated with the start-up of the coker at the CORE project at the Wood River Refinery in the fourth quarter of 2011;
- Realized risk management gains before tax, excluding Refining and Marketing, of $99 million compared to gains of $63 million in the third quarter of 2011;
- A decrease in royalties of $9 million, primarily as a result of lower crude oil reference prices and higher capital investment; and
- A 27 percent increase in our Crude Oil sales volumes as a result of higher production in all operating areas.

The increases in our cash flow from the third quarter of 2012 were partially offset by:

- A 38 percent decrease in the average natural gas sales price to $2.30 per Mcf;
- Natural gas production declining 12 percent, primarily as a result of expected natural declines and the divestiture of a non-core property early in the first quarter of 2012;
- A three percent decrease in the average sales price of Crude Oil to $65.35 per barrel;
- Crude Oil operating expenses increased $56 million, due to significantly higher production from Christina Lake phase C and phase D, as well as additional costs incurred at Foster Creek and Pelican Lake; and
- A $40 million increase in current income tax expense due to improved operating cash flow from our Canadian operations and higher U.S. state income tax.

Cash Flow Variance for the Nine Months Ended September 30, 2012 compared to September 30, 2011



Cash flow in the nine months ended September 30, 2012 increased $521 million primarily due to:

- An increase in operating cash flow from Refining and Marketing of $402 million, due to the combination of stronger refining margins and continued high throughput levels and refined product output associated with the start-up of the coker at the CORE project at the Wood River Refinery in the fourth quarter of 2011;
- Realized risk management gains before tax, excluding Refining and Marketing, of $230 million compared to gains of $53 million in 2011;
- A 23 percent increase in our Crude Oil sales volumes as a result of increased production in all operating areas; and
- A decrease in royalties of $29 million primarily as a result of increased capital investment at Foster Creek and Pelican Lake as well as lower crude oil prices. Royalties in 2011 included the Alberta Department of Energy approval to

include Foster Creek expansion phases F, G and H capital investment as part of the Foster Creek royalty calculation which reduced royalties by approximately $65 million.

The increases in our cash flow in the nine months ended September 30, 2012 were partially offset by:
- A 40 percent decrease in the average natural gas sales price to $2.25 per Mcf;
- Natural gas production declining eight percent, primarily as a result of expected natural declines and the divestiture of a non-core property early in the first quarter of 2012;
- A three percent decrease in the average sales price of Crude Oil to $67.89 per barrel;
- Operating expenses increased $181 million, primarily from crude oil production, due to the significant increase in production from Christina Lake phase C and phase D as well as an increase in costs from Conventional properties. Operating costs were also higher at Foster Creek and Pelican Lake; and
- A $94 million increase in current income tax expense due to improved operating cash flow from our Canadian operations and higher U.S. state income tax.

OPERATING EARNINGS

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Net Earnings	**$ 289**	$ 510	**$ 1,111**	$ 1,212
(Add back) deduct:				
Unrealized risk management gains (losses), after-tax [1]	**(218)**	283	**(44)**	314
Non-operating foreign exchange gains (losses), after-tax [2]	**76**	(76)	**100**	(11)
Gain (loss) on divestiture of assets, after-tax	**(1)**	-	**-**	2
Operating Earnings	**$ 432**	$ 303	**$ 1,055**	$ 907

[1] The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
[2] After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax gains (losses) on unrealized non-operating foreign exchange, after-tax effect of gains (losses) on divestiture of assets 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.

Operating earnings in the third quarter of 2012 rose from 2011 due to higher operating cash flow, partially offset by increased DD&A as a result of higher production and higher DD&A rates; increased general and administrative costs due to higher long-term incentive costs in comparison to a recovery of long-term incentive costs in the third quarter of 2011; and higher income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures) from increased operating cash flow from upstream and refining operations.

The increase in operating earnings for the nine months ended September 30, 2012 is due to higher operating cash flow, offset by increased general and administrative expenses, DD&A, exploration expense and higher income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

NET EARNINGS VARIANCE

(millions of dollars)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2011	$ 510	$ 1,212
Increase (decrease) due to:		
Operating Cash Flow	365	630
Corporate and Eliminations		
Unrealized risk management gains (losses), net of tax	(501)	(358)
Unrealized foreign exchange gains (losses)	123	83
Gain (loss) on divestitures	(1)	(3)
Expenses [1]	(63)	(46)
Depreciation, depletion and amortization	(79)	(264)
Exploration expense	-	(68)
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(65)	(75)
Net Earnings for the Periods Ended September 30, 2012	**$ 289**	**$ 1,111**

[1] Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net and Corporate and Eliminations operating expenses.

In the third quarter of 2012, our net earnings decreased $221 million compared to the third quarter of 2011 mainly due to:

- Increased operating cash flow as discussed above;
- Unrealized risk management losses, after-tax, of $218 million, compared to gains of $283 million in the third quarter of 2011;
- Unrealized foreign exchange gains of $60 million compared to losses of $63 million in the third quarter of 2011, consistent with the strengthening of the Canadian dollar exchange rate at September 30, 2012 on the translation of our U.S. dollar long-term debt, partially offset by the translation of our U.S. dollar denomination Partnership Contribution Receivable;
- An increase of $79 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs and CORE capital costs now subject to depreciation with the coker start-up in the fourth quarter of 2011, partially offset by decreased natural gas production;
- An increase of $66 million for general and administrative expenses due to higher office support costs and increased long-term incentive costs in comparison to a recovery of long-term incentive costs in the third quarter of 2011; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $261 million, compared to $196 million for the same period in 2011.

In the nine months ended September 30, 2012, our net earnings decreased $101 million compared to 2011. Significant factors that impacted our net earnings for the period include:

- Increased operating cash flow as discussed above;
- Unrealized risk management loss, after-tax, of $44 million, compared to gains of $314 million in 2011;
- Unrealized foreign exchange gains of $82 million compared to a loss of $1 million in 2011, consistent with the strengthening of the Canadian dollar exchange rate at September 30, 2012 on the translation of our U.S. dollar long-term debt, partially offset by the translation of our U.S. dollar denominated Partnership Contribution Receivable;
- An increase of $264 million in DD&A expense due to higher crude oil production, increased DD&A rates due to higher future development costs and increased depreciable costs in Refining and Marketing, partially offset by decreased natural gas production;
- Exploration expense of $68 million;
- An increase of $48 million for general and administrative expenses primarily due to increased long-term incentive expense and higher staffing and office support costs; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $608 million, compared to $533 million for the same period in 2011.

NET CAPITAL INVESTMENT

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Oil Sands	**$ 516**	$ 306	**$ 1,606**	$ 950
Conventional	**231**	193	**591**	458
Refining and Marketing	**38**	101	**60**	320
Corporate	**45**	31	**133**	92
Capital Investment	**830**	631	**2,390**	1,820
Acquisitions	**8**	1	**44**	22
Divestitures	**-**	-	**(65)**	(9)
Net Capital Investment [1]	**$ 838**	$ 632	**$ 2,369**	$ 1,833

[1] Includes expenditures on PP&E and E&E. For purposes of managing our capital program, we do not differentiate between PP&E and E&E expenditures, and therefore we have not split our capital investment within this MD&A.

Oil Sands capital investment in the three and nine months ended September 30, 2012 increased compared to 2011 primarily due to higher spending on module assembly and facility construction for phase F, piling work, steel fabrication and major equipment procurement for phase G and design engineering for phase H at Foster Creek. At Christina Lake, the increase in capital investment included phase E facility construction as well as phase F site preparation, engineering and major equipment fabrication. Pelican Lake capital investment included infill drilling for expansion of the polymer flood, facility expansion, pipeline construction and maintenance capital. Capital investment in 2012 includes the drilling of 429 gross stratigraphic test wells, down from the 443 gross wells drilled during the nine months ended September 30, 2011. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.

Conventional capital investment in the three and nine months ended September 30, 2012 was centered on the development of our crude oil properties including drilling, completion and facilities work in the Lower Shaunavon and Bakken areas of Saskatchewan as well as drilling programs in Alberta focused on tight oil. Our Conventional capital program is focused on meeting our Conventional crude oil production target of 65,000 to 75,000 barrels per day by the end of 2016.

Refining and Marketing capital investment in the three and nine months ended September 30, 2012 was primarily focused on maintenance capital and reliability projects now that the coker construction and start-up activities of the CORE project at the Wood River Refinery have been completed. In addition, we recognized Illinois tax credits of $14 million in the first quarter of 2012 related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment in 2012.

Included in our capital investment is spending on technology development. Our teams are always looking for ways to either improve existing technology or pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas. One of our ongoing objectives is to advance technologies that increase production while minimizing the use of water, natural gas, electricity and land. This philosophy is evidenced through the use of our Wedge Well™ technology at Foster Creek and Christina Lake and the use of enhanced start-up techniques at Christina Lake phase C.

Corporate capital investment was for tenant improvements to office space and information technology costs. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Acquisitions and Divestitures

The acquisitions were primarily for producing conventional crude oil properties in Alberta and Saskatchewan located adjacent to existing production. Divestitures in 2012 were mainly for the sale in the first quarter of a non-core natural gas property in northern Alberta.

CAPITAL INVESTMENT DECISIONS

The table below reflects the outcome of our capital allocation process. It is important to understand that our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash Flow	**$ 1,117**	$ 793	**$ 2,946**	$ 2,425
Capital Investment (Committed and Growth)	**830**	631	**2,390**	1,820
Free Cash Flow [1]	**287**	162	**556**	605
Dividends paid	**166**	150	**498**	452
	$ 121	$ 12	**$ 58**	$ 153

[1] Free cash flow is a non-GAAP measure defined as cash flow less capital investment.

RISK MANAGEMENT ACTIVITIES

We partially mitigate our exposure to financial risks, including cash flow, through the use of various financial instruments and physical contracts. Part of our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. In the third quarter, Cenovus executed a long term sales agreement with a crude oil end-user to deliver specific produced crude oil grades to help reduce our exposure to heavy oil price differentials.

Financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled. Mark-to-market changes are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

The realized risk management amounts in the table below impact our operating cash flow, cash flow, operating earnings and net earnings. Unrealized risk management amounts are a non-cash item included in net earnings and affect the Corporate and Eliminations segment's financial results. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

Financial Impact of Risk Management Activities

	Three Months Ended September 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ 26**	**$ (189)**	**$ (163)**	$ 8	$ 353	$ 361
Natural Gas	**65**	**(83)**	**(18)**	46	11	57
Refining	**6**	**(11)**	**(5)**	16	15	31
Power	**2**	**(10)**	**(8)**	9	2	11
Gains (Losses) on Risk Management	**99**	**(293)**	**(194)**	79	381	460
Income Tax Expense (Recovery)	**26**	**(75)**	**(49)**	23	98	121
Gains (Losses) on Risk Management, after-tax	**$ 73**	**$ (218)**	**$ (145)**	$ 56	$ 283	$ 339

For our risk management activities, we have transitioned to a more integrated view of our exposure across the upstream and refining businesses. We recognize that on an integrated basis, we have a long position in refined product which has become more strongly correlated to Brent crude rather than WTI. To better align our corporate risk management program with this exposure, we converted all existing 2013 WTI crude oil financial instruments to Brent during the third quarter. In addition, a further 17,000 barrels per day were executed through financial instruments at fixed Brent pricing, resulting in a total of 37,000 barrels per day locked into a weighted average Brent price of US$111.97 per barrel. Cenovus also executed a physical long-term sales agreement with a crude oil end user for specific product grades at a fixed light to heavy differentials. Details of financial instrument volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

In the third quarter of 2012, our strategy to manage commodity price risk generated realized gains on both our crude oil and natural gas financial instruments. Although the September 30 closing price of Brent crude rose US$14.59 per barrel from June 30, the average price during the third quarter firmed by less than a dollar; as a result, we recorded a realized gain from our crude oil financial instruments. Despite natural gas prices strengthening for the first time in over a year, we incurred a realized gain on our natural gas financial instruments due to the contract prices. An unrealized loss was recorded in the third quarter on our crude oil and natural gas financial contracts as a result of increases in forward commodity prices.

	Nine Months Ended September 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ 26**	**$ 102**	**$ 128**	$ (96)	$ 418	$ 322
Natural Gas	**200**	**(144)**	**56**	143	(38)	105
Refining	**18**	**(3)**	**15**	3	16	19
Power	**-**	**(15)**	**(15)**	6	26	32
Gains (Losses) on Risk Management	**244**	**(60)**	**184**	56	422	478
Income Tax Expense (Recovery)	**64**	**(16)**	**48**	15	108	123
Gains (Losses) on Risk Management, after-tax	**$ 180**	**$ (44)**	**$ 136**	$ 41	$ 314	$ 355

In the nine months ended September 30, 2012, our strategy to manage commodity price risk generated realized gains on both crude oil and natural gas financial instruments. We realized gains on our crude oil financial instruments as crude oil commodity prices were below the contract prices. Similarly, we incurred realized gains on our natural gas financial instruments due to low natural gas commodity prices in comparison to our contract prices.

Unrealized gains recorded on crude oil financial instruments in the first half of 2012 were partially offset by unrealized losses in the third quarter due to increasing crude oil forward prices. Natural gas financial instruments incurred unrealized losses to date in 2012 as a result of increasing forward natural gas commodity prices. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL PRODUCTION VOLUMES

(barrels per day)	**Q3 2012**	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010
Oil Sands									
Foster Creek	**63,245**	51,740	57,214	55,045	56,322	50,373	57,744	52,183	50,269
Christina Lake	**32,380**	28,577	24,733	19,531	10,067	7,880	9,084	8,606	7,838
Pelican Lake	**23,539**	22,410	20,730	20,558	20,363	19,427	21,360	21,738	23,259
Conventional									
Heavy Oil	**15,492**	15,703	16,624	15,512	15,305	15,378	16,447	16,553	16,921
Light & Medium Oil	**35,695**	36,149	36,411	32,530	30,399	27,617	31,539	29,323	28,608
Natural Gas Liquids [1]	**999**	987	1,138	1,097	1,040	1,087	1,181	1,190	1,172
	171,350	155,566	156,850	144,273	133,496	121,762	137,355	129,593	128,067

[1] Natural gas liquids include condensate volumes.

In the three and nine months ended September 30, 2012, our total Crude Oil production was higher than 2011 due to strong well performance and plant optimization at Foster Creek, the start-up of Christina Lake phases C and D and rising production at Pelican Lake from our infill drilling and polymer flood program. Our successful drilling program in Alberta and drilling, completions and facilities work in Saskatchewan also contributed to higher production. Further discussion on our Crude Oil production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	Q3 2012	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010
Conventional	**550**	563	595	622	617	617	620	649	694
Oil Sands	**27**	33	41	38	39	37	32	39	44
	577	596	636	660	656	654	652	688	738

Natural gas production declined 79 MMcf per day in the third quarter of 2012 compared to 2011 as low levels of capital investment are not sufficient to offset base declines and as a result of the divestiture of a non-core property early in the first quarter of 2012. Excluding the divestiture, our natural gas production would have decreased nine percent as a result of natural declines. For the nine months ended September 30, 2012, our natural gas production declined 53 MMcf per day to 602 MMcf per day (2011 – 655 MMcf per day). The reduction was primarily due to the factors that affected our production during the third quarter, partially offset by the absence of weather related production issues encountered in the first half of 2011. Excluding the impact of the first quarter divestiture, our natural gas production would have decreased five percent. Further discussion on our natural gas production can be found in the Reportable Segments section of this MD&A.

OPERATING NETBACKS

	Three Months Ended September 30,			
	2012		2011	
	Crude Oil ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil ($/bbl)	Natural Gas ($/Mcf)
Price [1]	**$ 65.35**	**$ 2.30**	$ 67.43	$ 3.72
Royalties	**7.83**	**0.02**	10.55	0.05
Transportation and blending [1]	**2.45**	**0.08**	2.38	0.15
Operating expenses	**14.14**	**1.08**	13.16	0.99
Production and mineral taxes	**0.53**	**0.02**	0.57	0.03
Netback excluding Realized Risk Management	**40.40**	**1.10**	40.77	2.50
Realized Risk Management Gains	**2.02**	**1.24**	0.75	0.76
Netback including Realized Risk Management	**$ 42.42**	**$ 2.34**	$ 41.52	$ 3.26

[1] The Crude Oil price and transportation and blending costs exclude $23.06 per barrel (2011 – $21.14 per barrel) of condensate purchases which is blended with heavy crude oil.

In the third quarter of 2012, our average netback for Crude Oil, excluding realized risk management gains and losses, were relatively consistent with the prior year, decreasing by $0.37 per barrel from 2011. Sales prices were lower in the current quarter due to a combination of lower realized prices for Christina Lake because of the Christina Dilbit Blend ("CDB") differential to WCS and lower conventional prices in line with lower benchmarks. This was offset by decreased royalty rates reflecting lower sales prices in the current quarter and increased capital investment. Netbacks were also impacted by higher operating costs as a result of workforce, workover activities and waste, fluid handling and trucking costs.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.40 per Mcf in the third quarter of 2012 predominantly as a result of lower sales prices in the current quarter.

	Nine Months Ended September 30,			
	2012		2011	
	Crude Oil ($/bbl)	Natural Gas ($/Mcf)	Crude Oil ($/bbl)	Natural Gas ($/Mcf)
Price [1]	$ 67.89	$ 2.25	$ 70.15	$ 3.75
Royalties	6.91	0.03	9.18	0.06
Transportation and blending [1]	2.69	0.10	2.45	0.15
Operating expenses	14.27	1.05	13.25	1.05
Production and mineral taxes	0.56	0.02	0.53	0.05
Netback excluding Realized Risk Management	43.46	1.05	44.74	2.44
Realized Risk Management Gains (Losses)	0.66	1.21	(2.66)	0.80
Netback including Realized Risk Management	$ 44.12	$ 2.26	$ 42.08	$ 3.24

(1) The Crude Oil price and transportation and blending costs exclude $26.96 per barrel (2011 – $24.07 per barrel) of condensate purchases which is blended with heavy crude oil.

In the nine months ended September 30, 2012, our average netback for Crude Oil, excluding realized risk management gains and losses, decreased by $1.28 per barrel primarily due to decreased sales prices for Christina Lake due to the CDB differential to WCS. Royalties declined as a result of lower sales prices and increased capital investment. Netbacks were also impacted by higher operating expenses, which rose due to increased workforce costs, additional workover activity and higher fluid and waste trucking costs.

Our average netback for natural gas, excluding realized risk management gains and losses, was $1.39 per Mcf lower in the nine months ended September 30, 2012 than in the comparable period. The decrease is largely due to lower sales prices, partially offset by decreased royalties and lower transportation expenses.

Further discussion on the items included in our operating netbacks is included in the Reportable Segments section of this MD&A. Further information on our risk management strategy can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

REPORTABLE SEGMENTS

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in the third quarter of 2012 include:
- Achieving first production from Christina Lake phase D in late July 2012;
- Christina Lake setting a new single day gross production high of over 87,000 barrels per day;
- Christina Lake production averaging 32,380 barrels per day, more than a threefold increase due to the start of phases C and D in the third quarters of 2011 and 2012, respectively;
- Foster Creek production averaging 63,245 barrels per day, a 12 percent increase as a result of improved well performance and plant optimization; and
- Pelican Lake production averaging 23,539 barrels per day, an increase of 16 percent, as a result of our infill and polymer flood programs.

OIL SANDS - CRUDE OIL

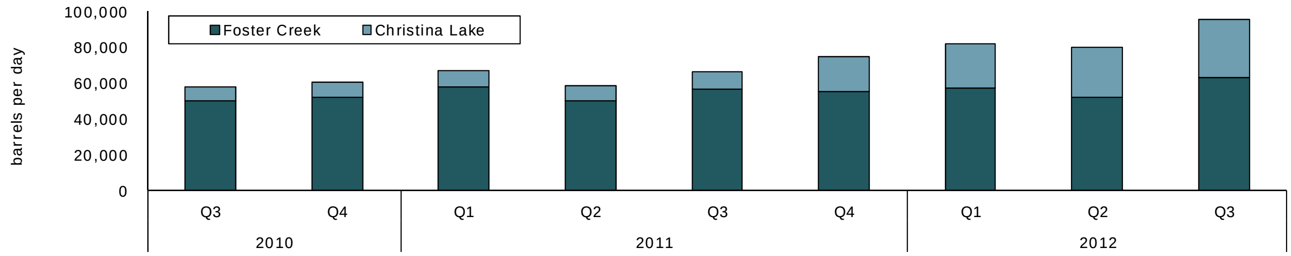
Financial Results

(millions of dollars)	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Gross sales	**$ 998**	$ 736	**$ 2,994**	$ 2,286
Less: Royalties	**84**	82	**175**	189
Revenues	**914**	654	**2,819**	2,097
Expenses				
Transportation and blending	**367**	263	**1,211**	868
Operating	**142**	103	**405**	301
(Gains) losses on risk management	**(23)**	(8)	**(20)**	61
Operating Cash Flow	**428**	296	**1,223**	867
Capital Investment	**515**	309	**1,600**	938
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (87)**	$ (13)	**$ (377)**	$ (71)

Production Volumes

Crude oil (barrels per day)	Three Months Ended September 30, 2012	2012 vs. 2011	2011	Nine Months Ended September 30, 2012	2012 vs. 2011	2011
Foster Creek	**63,245**	**12%**	56,322	**57,421**	**5%**	54,808
Christina Lake	**32,380**	**222%**	10,067	**28,577**	**217%**	9,014
Subtotal	**95,625**	**44%**	66,389	**85,998**	**35%**	63,822
Pelican Lake	**23,539**	**16%**	20,363	**22,231**	**9%**	20,380
	119,164	**37%**	86,752	**108,229**	**29%**	84,202

Foster Creek and Christina Lake Production Volumes by Quarter



Three Months Ended September 30, 2012 compared to September 30, 2011

Revenues Variances

(millions of dollars)	Three Months Ended September 30, 2011	Price	Volume	Royalties	Condensate[1]	**Three Months Ended September 30, 2012**
	$ 654	(13)	176	(2)	99	**$ 914**

[1] Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In the third quarter, our average crude oil sales price decreased two percent to $61.71 per barrel compared to 2011, consistent with the decline in the WCS benchmark price and higher volumes of CDB sales at a discount to WCS, partially offset by lower condensate costs. We expect that the CDB differential to WCS will continue to narrow as it gains acceptance with a wider base of refining customers, including the Wood River Refinery which processed approximately 28,000 barrels per day of CDB in the quarter. Approximately 85 percent of our Christina Lake production is sold as CDB and the remaining production is sold as part of the WCS stream, subject to a quality equalization charge.

The substantial increase in production at Christina Lake was the result of the start-up of phases C and D in the third quarters of 2011 and 2012, respectively. Phase D increases Christina Lake's expected gross production capacity by 40,000 barrels per day to a total of 98,000 barrels per day. Foster Creek production increased in the third quarter compared to 2011 as a result of improved well performance and plant optimization. The plant continues to demonstrate excellent performance and third quarter gross production averaged over 126,000 barrels per day, exceeding plant capacity. Pelican Lake production has steadily increased over the last five quarters. Average production in the third quarter of 2012 increased 16 percent from 2011 at Pelican Lake due to our infill drilling program and polymer flood activities.

Royalty calculations for our oil sands projects differ between properties. Pre-payout royalties at Christina Lake are a function of the Canadian dollar WTI benchmark price and volumes. Royalties for post-payout projects at Foster Creek and Pelican Lake are calculated on a net profits basis and are impacted by volumes, an annualized WTI price and allowed operating and capital costs. Royalties in the three months ended September 30, 2012 were consistent with 2011 as the increase in capital investment at Foster Creek and Pelican Lake were offset by production increases and the increase in forecasted WTI prices for 2012. The effective royalty rates for the third quarter of 2012 were 19.1 percent at Foster Creek (2011 – 20.6 percent), 5.3 percent at Christina Lake (2011 – 5.7 percent) and 6.6 percent at Pelican Lake (2011 – 12.7 percent).

Transportation and blending costs increased $104 million in the third quarter of 2012. The condensate portion was $99 million, the result of additional condensate volumes required to blend due to increased production at Foster Creek and Christina Lake, partially offset by a decrease in the average cost of condensate. Transportation costs increased as a result of higher production at Christina Lake. This was partially offset by lower transportation charges on the Trans Mountain pipeline system under our long-term commitment for firm service, which commenced in February 2012.

Our operating costs for the third quarter of 2012 were predominantly for workforce costs, workovers, repairs and maintenance and fuel costs at Foster Creek and Christina Lake. In total, operating costs increased $39 million in the third quarter of 2012 mainly due to higher staffing levels, fuel and chemical usage and fluid and waste handling associated with the start-up of Christina Lake phases C and D in the third quarters of 2011 and 2012, respectively. On a per barrel basis, Christina Lake operating costs decreased 41 percent to $13.59 per barrel due to the increase in production. Operating costs increased $11 million at Pelican Lake due to higher staffing levels, workovers, repairs and maintenance and chemicals. Foster Creek operating costs increased $8 million primarily due to higher staffing levels.

Risk management activities resulted in realized gains of $23 million (2011 – gains of $8 million), consistent with our 2012 contract prices exceeding average benchmark prices in the third quarter of 2012.

Nine Months Ended September 30, 2012 compared to September 30, 2011

Revenues Variances

(millions of dollars)	Nine Months Ended September 30, 2011	Price	Volume	Royalties	Condensate[1]	**Nine Months Ended September 30, 2012**
	$ 2,097	(59)	441	14	326	**$ 2,819**

[1] Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In the nine months ended September 30, 2012, our average crude oil sales price was $63.07 per barrel, a three percent decrease from 2011. To date in 2012, approximately 70 percent of our Christina Lake production has been sold as CDB. The remaining Christina Lake production is being sold as part of the WCS stream, and is subject to a quality equalization charge.

In the nine months ended September 30, 2012, the substantial increase in production at Christina Lake resulted from the start-up of phase C in the third quarter of 2011 and phase D coming on production in late July 2012. Foster Creek production increased from 2011 due to the plant continuing to operate above gross nameplate capacity and strong well performance. Pelican Lake production steadily rose with production averaging nine percent higher than in 2011. The increases at Pelican Lake resulted from infill wells brought on production in the second and third quarters of 2012. Production in 2011 at Pelican Lake was curtailed by approximately 1,100 barrels per day as a result of a scheduled plant turnaround and wild fires in the area in the second quarter.

Royalty calculations for our oil sands projects differ between properties. Pre-payout royalties at Christina Lake are a function of the Canadian dollar WTI benchmark price and volumes. Royalties for post-payout projects at Foster Creek and Pelican Lake are calculated on a net profits basis and are impacted by volumes, an annualized WTI price and allowed operating and capital costs. Royalties decreased $14 million in the nine months ended September 30, 2012 primarily due to increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets and higher forecasted WTI prices for 2012. Royalties also declined in 2011 upon receiving approval from the Alberta Department of Energy to include Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. The effective royalty rates for the nine months ended September 30, 2012 were 13.0 percent at Foster Creek (2011 – 14.8 percent), 6.4 percent at Christina Lake (2011 – 5.6 percent) and 5.1 percent at Pelican Lake (2011 – 12.1 percent).

Transportation and blending costs rose $343 million in the nine months ended September 30, 2012. The majority of the cost increase, $326 million, stems from additional condensate volumes required to blend with higher production at Christina Lake and Foster Creek, partially offset by a decrease in the average cost of condensate. Transportation costs were also impacted by higher production at Christina Lake. This was partially offset by lower transportation charges on the Trans Mountain pipeline system under our long-term commitment for firm service, which commenced in February 2012.

Our operating costs for the nine months ended September 30, 2012 were primarily for workforce costs, workovers, repairs and maintenance and chemical usage across all three operations, as well as fuel costs specific to Foster Creek and Christina Lake. In total, operating costs increased $104 million in the nine months ended September 30, 2012 mainly due to higher staffing levels, fuel and chemical usage, workovers and fluid and waste handling associated with the start-up of Christina Lake phases C and D in the third quarters of 2011 and 2012, respectively. On a per barrel basis, Christina Lake operating costs decreased 37 percent to $13.76 per barrel due to the increase in production. Operating costs increased $29 million at Pelican Lake primarily as the result of additional workovers, workforce costs, increased chemical usage and higher repairs and maintenance. Foster Creek operating costs increased $22 million due to increased workforce costs, workovers and higher levels of fluid and waste trucking activity.

Risk management activities resulted in realized gains of $20 million (2011 – losses of $61 million), consistent with our 2012 contract prices exceeding average benchmark prices in the nine months ended September 30, 2012.

OIL SANDS - NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor natural gas properties. Our natural gas production decreased to 27 MMcf per day in the third quarter of 2012 (2011 – 39 MMcf per day) as the result of anticipated natural declines, partially offset by a reduction in the use of our natural gas production at our Foster Creek operation. Natural gas production decreased slightly to 33 MMcf per day for the nine months ended September 30, 2012 (2011 – 37 MMcf per day) for identical reasons.

Reduced natural gas production in combination with lower prices resulted in operating cash flow declining to $8 million for the third quarter of 2012 (2011 – $17 million). Similarly, operating cash flow for the nine months ended September 30, 2012 declined to $21 million (2011 – $40 million) due to the combination of lower natural gas prices and decreasing production.

OIL SANDS - CAPITAL INVESTMENT

(millions of dollars)	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
Foster Creek	**$ 199**	$ 110	**$ 527**	$ 290
Christina Lake	**147**	117	**412**	346
Subtotal	**346**	227	**939**	636
Pelican Lake	**128**	70	**371**	185
Narrows Lake	**7**	1	**25**	13
Telephone Lake	**13**	2	**117**	33
Grand Rapids	**7**	1	**46**	14
Other [1]	**15**	5	**108**	69
Capital Investment [2]	**$ 516**	$ 306	**$ 1,606**	$ 950

[1] Includes emerging new resource plays and Athabasca natural gas.
[2] Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2012 has been primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, facility expansion and infill drilling activities related to our Pelican Lake polymer flood, drilling of stratigraphic test wells in the first quarter to support the development of our Oil Sands projects and successfully completing the winter work needed to commence operation of the dewatering project at Telephone Lake.

Foster Creek capital investment increased in 2012 compared to 2011 primarily as a result of higher phase F spending on module assembly and facility construction, phase G spending on piling work, steel fabrication and major equipment procurement and phase H design engineering. Our year-to-date capital includes the drilling of 124 gross stratigraphic test wells in 2012 (2011 – 111 wells).

Christina Lake capital investment increased in 2012 compared to 2011 primarily due to phase E facility construction and phase F site preparation, engineering and major equipment fabrication. Capital investment in 2012 also included the drilling of stratigraphic test wells (2012 – 28 gross wells; 2011 – 59 gross wells). The increases in capital investment were partially offset by the completion of phases C and D construction in the second quarters of 2011 and 2012, respectively. First steam at phase D was achieved in the second quarter and first production from phase D was achieved in late July 2012. Production from phase E is expected in the fourth quarter of 2013.

Pelican Lake capital investment for the three and nine months ended September 30, 2012 was primarily related to infill drilling to progress the polymer flood, facilities expansions, pipeline construction and maintenance capital. Facilities spending focused on expanding fluid handling capacity at Pelican Lake through additions and upgrades to our oil treating units and emulsion pipelines.

Remaining capital investment in 2012 was focused on the drilling of stratigraphic test and observation wells, mainly in the Borealis Region, Narrows Lake, Grand Rapids and Telephone Lake, as well as the progression of a dewatering project at Telephone Lake.

Production Wells

(gross production wells drilled [1])	Nine Months Ended September 30, 2012	2011
Foster Creek	**20**	15
Christina Lake	**25**	16
Subtotal	**45**	31
Pelican Lake	**52**	19
Grand Rapids	**1**	-
Other	**-**	3
	98	53

[1] Includes wells drilled using our Wedge Well™ technology.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed another large stratigraphic test well program in the first quarter of 2012. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter.

	Nine Months Ended September 30,	
(gross stratigraphic test wells drilled)	**2012**	2011
Foster Creek	**124**	111
Christina Lake	**28**	59
Subtotal	**152**	170
Pelican Lake	**5**	59
Narrows Lake	**38**	41
Grand Rapids	**41**	38
Telephone Lake	**29**	40
Borealis (including Steepbank)	**58**	44
Other	**106**	51
	429	443

In addition, we drilled 26 observation wells (2011 – nil) in the nine months ended September 30, 2012, mainly at Telephone Lake and Grand Rapids to support the pilot projects. Observation wells are cased wells which are used to monitor and measure changes in pressure, temperature and manage the reservoir.

CONVENTIONAL

Our Conventional operations include the development and production of Crude Oil and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise a mix of predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. Our Saskatchewan properties include the carbon dioxide enhanced oil recovery project at Weyburn and the Lower Shaunavon and Bakken crude oil properties. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in the third quarter of 2012 include:

- Alberta Crude Oil production averaging 29,833 barrels per day, increasing 10 percent primarily due to successful tight oil drilling programs and fewer weather and access issues than in the third quarter of 2011;
- Average Crude Oil production from our Lower Shaunavon and Bakken tight oil plays increasing 56 percent to 6,252 barrels per day due to ongoing drilling;
- Completed construction of the Lower Shaunavon battery and commenced commissioning activities;
- Natural gas production decreasing 11 percent to 550 MMcf per day due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines;
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $111 million; and
- Maintaining our crude oil focus, with capital investments totaling $231 million for drilling, completions and facilities activities.

CONVENTIONAL - CRUDE OIL

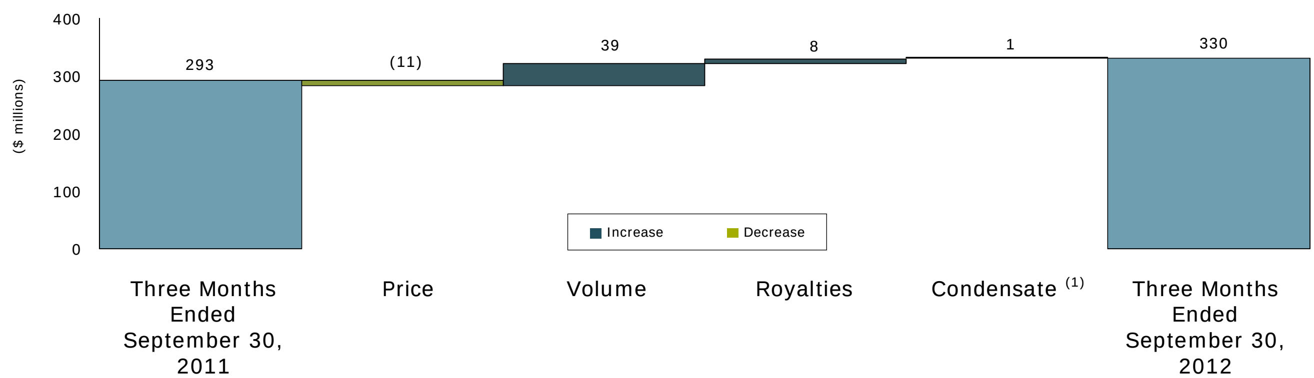
Financial Results

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Gross sales	**$ 368**	$ 339	**$ 1,187**	$ 1,076
Less: Royalties	**38**	46	**130**	139
Revenues	**330**	293	**1,057**	937
Expenses				
Transportation and blending	**27**	23	**96**	78
Operating	**78**	61	**224**	175
Production and mineral taxes	**7**	7	**24**	19
(Gains) losses on risk management	**(9)**	(7)	**(9)**	30
Operating Cash Flow	**227**	209	**722**	635
Capital Investment	**224**	168	**562**	387
Operating Cash Flow in Excess of Related Capital Investment	**$ 3**	$ 41	**$ 160**	$ 248

Production Volumes

	Three Months Ended September 30,			Nine Months Ended September 30,		
(barrels per day)	**2012**	**2012 vs. 2011**	2011	**2012**	**2012 vs. 2011**	2011
Heavy Oil						
Alberta	**15,492**	**1%**	15,305	**15,938**	**1%**	15,706
Light and Medium Oil						
Alberta	**13,407**	**25%**	10,724	**13,279**	**23%**	10,777
Saskatchewan	**22,288**	**13%**	19,675	**22,804**	**20%**	19,070
Natural Gas Liquids	**999**	**-4%**	1,040	**1,041**	**-6%**	1,102
	52,186	**12%**	46,744	**53,062**	**14%**	46,655

Revenues Variance for the Three Months Ended September 30, 2012 compared to September 30, 2011



[1] Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

Three Months Ended September 30, 2012 compared to September 30, 2011

Our average Crude Oil sales price for the third quarter decreased three percent to $73.44 per barrel compared to 2011, consistent with the decline in relevant crude oil benchmark prices and resulting movement in associated discounts.

Our Crude Oil production increased 12 percent in the third quarter as a result of successful capital programs. Crude Oil production from our Lower Shaunavon and Bakken areas rose 56 percent from the same period in 2011 to 6,252 barrels per day. In Alberta, production of Crude Oil in the third quarter averaged 29,833 barrels per day, just short of the daily production milestone of 30,000 barrels per day achieved in the first and second quarters.

Royalties decreased by $8 million primarily as a result of decreased crude oil prices partially offset by increased volumes. The effective crude oil royalty rate for the three months ended September 30, 2012 was 11.1 percent (2011 – 14.6 percent).

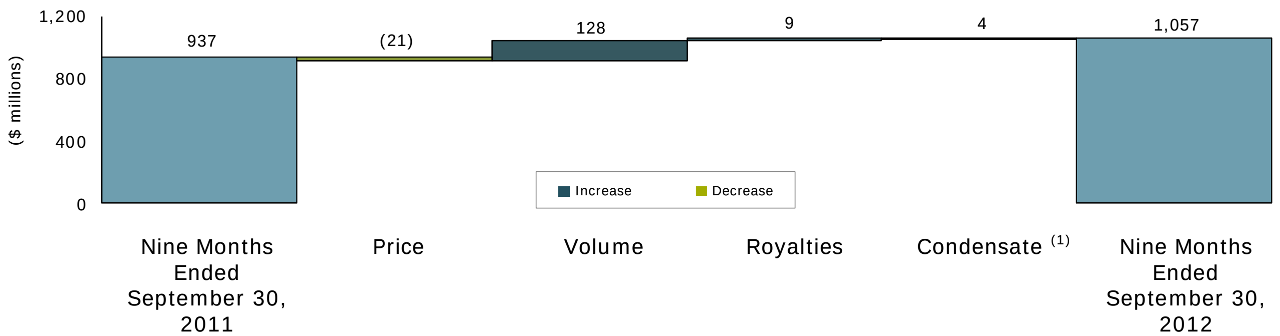
Transportation and blending costs increased $4 million compared to 2011. The overall cost of condensate used in blending increased $1 million. Transportation costs increased $3 million as a higher proportion of our volumes were shipped subject to spot pipeline tolls. The costs of accessing new markets, such as transporting our growing light and medium crude oil production by rail, also impacted the quarter.

The majority of our operating costs were composed of workover activity, electricity, repairs and maintenance, workforce costs and trucking and waste handling costs. Operating costs rose $17 million in the third quarter of 2012 primarily due to increases in electrical costs, repairs and maintenance expenses as well as trucking and waste handling costs in connection with single well batteries. These cost increases partly reflect the shift in our strategic focus from natural gas to crude oil which has resulted in higher liquids production.

Risk management activities for the three months ended September 30, 2012 resulted in realized gains of $9 million (2011 – gains of $7 million), consistent with our 2012 contract prices exceeding the average benchmark prices in the third quarter of 2012.

Operating cash flow from Conventional Crude Oil in excess of capital investment decreased by $38 million in the third quarter of 2012. This resulted from the combination of an $18 million increase in operating cash flow offset by $56 million of additional capital investment mainly due to increased facility expenditures.

Revenues Variance for the Nine Months Ended September 30, 2012 compared to September 30, 2011



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

Nine Months Ended September 30, 2012 compared to September 30, 2011

Our average Crude Oil sales price for the nine months ended September 30, 2012 decreased to $77.74 per barrel compared to the same period in 2011, consistent with the minimal change in crude oil benchmark prices and associated differentials.

Our Crude Oil production increased 14 percent in the nine months ended September 30, 2012 as a result of successful capital programs, partially offset by expected natural declines. Production of Crude Oil in Alberta averaged 30,198 barrels per day in the nine months ended September 30, 2012. Average production from our Lower Shaunavon and Bakken areas averaged 6,483 barrels per day, increasing 107 percent from the same period in 2011.

Royalties decreased $9 million from 2011 as increased production from Alberta crown land was offset by a Saskatchewan enhanced oil recovery credit related to prior periods and slightly lower prices. The effective crude oil royalty rate for the nine months ended September 30, 2012 was 12.2 percent (2011 – 14.2 percent).

Transportation and blending costs increased $18 million in the nine months ended September 30, 2012 compared to 2011. The overall cost of condensate used in blending increased $4 million. Transportation costs increased $14 million as a higher proportion of our volumes were shipped subject to spot pipeline tolls. The costs of accessing new markets, such as transporting our growing light and medium crude oil production by rail, also contributed to higher transportation costs.

Operating costs were predominantly comprised of workover activities, electricity costs, repairs and maintenance and workforce costs. Operating costs rose $49 million in the nine months ended September 30, 2012 primarily due to a combination of higher workover costs, repairs and maintenance activity and trucking and waste handling costs in connection with single well batteries. These increases reflect the shift in strategic focus from natural gas to crude oil which has resulted in higher liquids production.

Risk management activities for the nine months ended September 30, 2012 created a realized gain of $9 million (2011 – loss of $30 million).

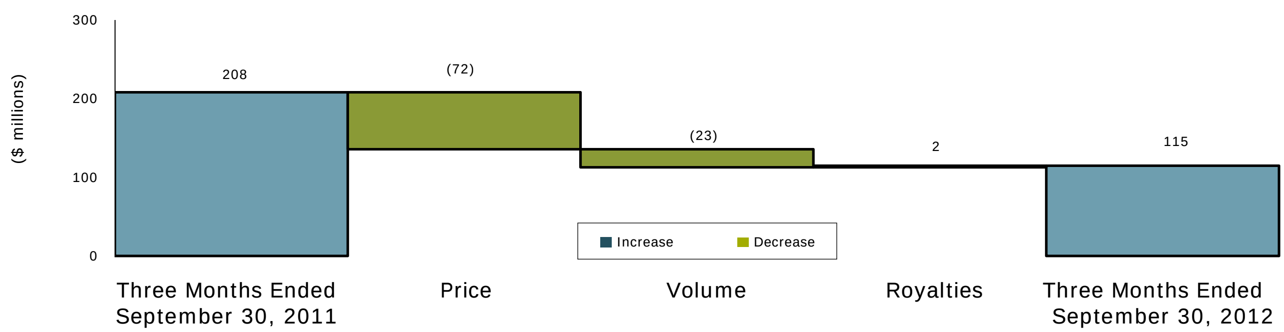
Operating cash flow from Conventional Crude Oil in excess of capital investment decreased by $88 million in the nine months ended September 30, 2012 as the $87 million increase in operating cash flow was more than offset by the $175 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan.

CONVENTIONAL - NATURAL GAS

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Gross sales	**$ 116**	$ 211	**$ 350**	$ 633
Less: Royalties	**1**	3	**4**	9
Revenues	**115**	208	**346**	624
Expenses				
Transportation and blending	**4**	8	**15**	26
Operating	**53**	59	**155**	173
Production and mineral taxes	**2**	2	**4**	8
(Gains) losses on risk management	**(62)**	(44)	**(186)**	(132)
Operating Cash Flow	**118**	183	**358**	549
Capital Investment	**7**	25	**29**	71
Operating Cash Flow in Excess of Related Capital Investment	**$ 111**	$ 158	**$ 329**	$ 478

Revenues Variance for the Three Months Ended September 30, 2012 compared to September 30, 2011



Three Months Ended September 30, 2012 compared to September 30, 2011

Our natural gas revenues and operating cash flow decreased in the third quarter due to a combination of lower average sales prices in addition to reduced production volumes, consistent with the decline in the benchmark AECO price. Our natural gas production in the three months ended September 30, 2012 decreased 11 percent to 550 MMcf per day, partly due to the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 23 MMcf per day. Further production decreases stemmed from expected natural declines. Excluding the impact of the non-core divestiture, our natural gas production would have decreased by seven percent from the same period in 2011.

Royalties decreased $2 million in the three months ended September 30, 2012 due to lower prices and volumes. The average royalty rate in the third quarter of 2012 was 1.1 percent (2011 – 1.8 percent).

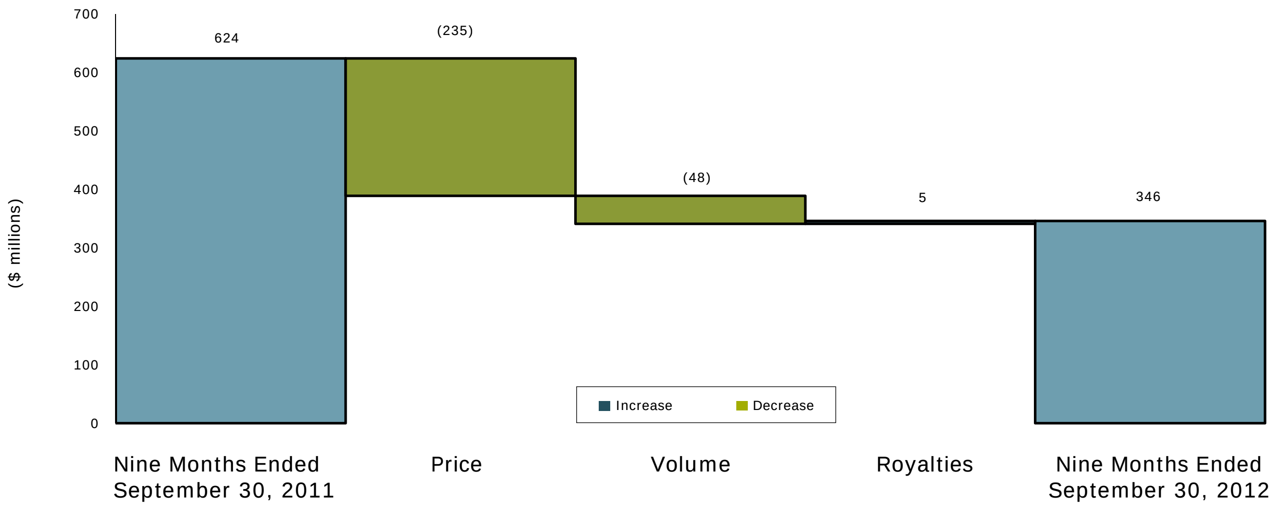
Transportation costs declined $4 million primarily due to lower production volumes and lower transportation rates.

Our operating expenses are composed primarily of property taxes and lease costs, repairs and maintenance, workforce costs and electricity. Operating expenses decreased $6 million in the third quarter of 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 lowered workover activity and repairs and maintenance. These decreases were partly offset by higher electrical and property taxes and lease costs.

Risk management activities for the three months ended September 30, 2012 resulted in realized gains of $62 million (2011 – gains of $44 million) consistent with our 2012 contract price exceeding the average benchmark prices.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $47 million primarily due to lower average sales prices and production volumes partially offset by an $18 million reduction in capital investment.

Revenues Variance for the Nine Months Ended September 30, 2012 compared to September 30, 2011



Nine Months Ended September 30, 2012 compared to September 30, 2011

Our natural gas revenues and operating cash flow decreased in the nine months ended September 30, 2012, due to a combination of lower average sales prices and reduced production, consistent with the decline in the benchmark AECO price. Our natural gas production decreased eight percent to 569 MMcf per day, primarily due to expected natural declines. Further production decreases stemmed from the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 20 MMcf per day. Excluding the impact of the non-core divestiture, our natural gas production would have been five percent lower than the same period in 2011.

Royalties decreased $5 million in the nine months ended September 30, 2012 due lower volumes in combination with lower prices. The average royalty rates in the nine months ended September 30, 2012 were 1.3 percent (2011 – 1.5 percent).

Transportation costs decreased $11 million primarily due to lower production volumes.

Our operating expenses are composed largely of property taxes and lease costs, repairs and maintenance and workforce costs. Operating expenses decreased $18 million in the nine months ended September 30, 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 lowered workforce costs, repairs and maintenance activity as well as workover activity.

Risk management activities in the nine months of 2012 resulted in realized gains of $186 million (2011 – gains of $132 million) consistent with our 2012 contract price exceeding the average benchmark prices.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $149 million primarily due to lower average sales prices and production volumes partially offset by a $42 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Crude Oil	**$ 224**	$ 168	**$ 562**	$ 387
Natural Gas	**7**	25	**29**	71
Capital Investment [1]	**$ 231**	$ 193	**$ 591**	$ 458

[1] Includes expenditures on PP&E and E&E assets.

Capital investments in our Conventional segment focused on crude oil opportunities. Capital was invested in our 2012 tight oil drilling program primarily on fee lands in southeast Alberta. In Saskatchewan, facilities construction progressed in the third quarter of 2012 at Lower Shaunavon in addition to the battery constructed at Bakken earlier in the year. These facilities are expected to mitigate future downtime due to poor weather conditions and reduce trucking costs from single well batteries. Drilling and completions were conducted in the Lower Shaunavon and Bakken areas in addition to drilling and facilities work completed at Weyburn. Spending on natural gas activities was reduced in response to the current natural gas price environment.

The following table details our Conventional drilling activity. The crude oil wells drilled reflect the continued development of our Alberta properties as well as the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

Conventional Wells Drilled

	Nine Months Ended September 30,	
(net wells)	**2012**	2011
Crude oil	**202**	202
Natural gas	**-**	44
Recompletions	**745**	807
Stratigraphic test wells	**7**	9

REFINING AND MARKETING

The Refining and Marketing segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by Phillips 66. Our refining segment allows us to capture the full value from crude oil production through to refined products such as diesel, gasoline and jet fuel.

Since the Wood River Refinery and Borger Refinery are located in the U.S., this segment's results are affected by changes in the U.S./Canadian dollar exchange rate. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar increases our reported results, although a weaker Canadian dollar also increases our current period's refining capital investment.

This segment also includes the results of marketing third party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Significant factors related to our Refining and Marketing segment in the third quarter of 2012 include:

- Our refineries processing 442,000 barrels per day of crude oil, including 210,000 barrels per day of Canadian heavy crude oil, resulting in 463,000 barrels per day of refined product output;
- Strong refining margins resulting from higher benchmark crack spreads and discounted crude oil feedstock costs; and
- Operating cash flow increasing by $289 million to $527 million primarily due to the combination of strong refining margins and continued high throughput levels and refined product output.

Financial Results

(millions of dollars)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	**2012**	2011
Revenues	**$ 3,066**	$ 2,691	**$ 9,020**	$ 7,698
Purchased product	**2,403**	2,357	**7,500**	6,609
Gross margin	**663**	334	**1,520**	1,089
Expenses				
Operating expenses	**136**	112	**389**	349
(Gain) loss on risk management	**-**	(16)	**(14)**	(3)
Operating Cash Flow	**527**	238	**1,145**	743
Capital Investment	**38**	101	**60**	320
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 489**	$ 137	**$ 1,085**	$ 423

The gross margin for the Refining and Marketing segment increased $329 million in the third quarter of 2012 (year-to-date – $431 million) due to a combination of strong refining margins and higher throughput levels and refined product output subsequent to the start-up of the coker at the CORE project at the Wood River Refinery in the fourth quarter of 2011. In the first nine months of 2012, refining margins were higher in comparison to 2011 mainly as a result of a significant increase in heavy crude oil processed and higher clean product yield at Wood River. Feedstock costs are accounted for on a first-in, first-out basis and have benefited from relative discounts on heavy crude oil and U.S. inland crude oil.

Total operating costs consist mainly of labour, maintenance, utilities and supplies. Operating costs for the current quarter rose by $24 million and increased $40 million for the nine months ended September 30, 2012 due to higher labour and maintenance expenses, consistent with higher utilization, as well as costs related to planned turnaround activities. While there is an increase in utility usage at the Wood River Refinery subsequent to CORE project start-up, utilities costs have declined at both refineries from the same period in 2011 due to significantly lower prices for fuel gas and electricity.

Operating cash flow from the Refining and Marketing segment increased $289 million to $527 million in the third quarter of 2012 and rose $402 million in the nine months ended September 30, 2012 to $1,145 million as a result of higher gross margins partially offset by increased operating costs.

Capital investment decreased by $63 million in the third quarter of 2012 (year-to-date – $260 million) with the completion of the CORE project at the Wood River Refinery in the fourth quarter of 2011. Our year-to-date capital investment was further reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

REFINERY OPERATIONS [1]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	**2012**	2011
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**442**	413	**446**	394
Crude utilization *(%)*	**98**	91	**99**	87
Refined products *(Mbbls/d)*	**463**	426	**467**	411

[1] Represents 100 percent of the Wood River and Borger refinery operations. We have a 50 percent ownership in these operations.

Refinery operations in the three and nine months ended September 30, 2012 reflect the start-up of the coker at the CORE project in the fourth quarter of 2011, which significantly increased crude oil runs and refined product output.

Late in the third quarter, utilization rates were reduced in advance of the planned refinery turnarounds at both the Wood River and Borger Refineries. As scheduled, the turnarounds are currently proceeding and are expected to be completed in the fourth quarter. Combined refinery crude utilization in the last quarter of 2012 will be impacted by the successful completion of the turnarounds and related restarts and, as a result, will be lower than the previous quarters of 2012.

The total processing capability of Canadian heavy crude oils remains dependent on the quality of available crude oils and will be optimized to maximize economic benefit. In the third quarter, the Wood River Refinery processed approximately 28,000 barrels per day of CDB originating from our Christina Lake operations, further demonstrating our integrated oil strategy and the growing acceptance of CDB by refineries.

REFINING AND MARKETING - CAPITAL INVESTMENT

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Wood River Refinery	**$ 22**	$ 91	**$ 28**	$ 291
Borger Refinery	**15**	10	**31**	28
Marketing	**1**	-	**1**	1
Capital Investment	**$ 38**	$ 101	**$ 60**	$ 320

Our capital investment in the Refining and Marketing segment declined significantly in 2012 with the completion of the CORE project in the fourth quarter of 2011. Capital expenditures in 2012 were focused on maintenance and projects improving refinery reliability. Our year-to-date capital investment was further reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

CORPORATE AND ELIMINATIONS

Financial Results

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues	**$ (100)**	$ (9)	**$ (165)**	$ (50)
Expenses ((add)/deduct)				
Purchased product	**(100)**	(9)	**(165)**	(50)
Operating	**(1)**	(1)	**(2)**	(1)
(Gains) losses on risk management	**293**	(381)	**60**	(422)
	$ (292)	$ 382	**$ (58)**	$ 423

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on the long-term power purchase contract.

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

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
General and administrative	**$ 104**	$ 38	**$ 254**	$ 206
Finance costs	**120**	112	**344**	335
Interest income	**(28)**	(31)	**(84)**	(94)
Foreign exchange (gain) loss, net	**(51)**	85	**(42)**	56
(Gain) loss on divestitures	**1**	-	**-**	(3)
Other (income) loss, net	**-**	1	**(4)**	1
	$ 146	$ 205	**$ 468**	$ 501

General and administrative expenses rose $66 million in the third quarter predominantly due to higher long-term incentive costs and increased office support costs. The third quarter of 2011 benefited from a recovery of long-term incentive costs consistent with the decline in related share prices at that time. The year-to-date increase of $48 million in general and administrative costs stemmed from higher long-term incentive expenses, office services as well as staffing and support costs, including training and development.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In the third quarter, our finance costs were $8 million higher than 2011 (year-to-date – $9 million higher) due to the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by lower interest incurred on the Partnership Contribution Payable as the balance is repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the third quarter of 2012 was 5.2 percent (2011 – 5.4 percent) and for the nine months ended September 30, 2012 was 5.3 percent (2011 – 5.4 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated Partnership Contribution Receivable as well as short-term investments. When compared to the same periods in 2011, interest income for the third quarter of 2012 decreased by $3 million and for the nine months ended September 30, 2012 decreased by $10 million. These decreases are consistent with lower interest being earned on the Partnership Contribution Receivable as the balance is collected.

In the third quarter, we reported net foreign exchange gains of $51 million (2011 – losses of $85 million), which includes unrealized gains of $60 million (2011 – unrealized losses of $63 million) and realized losses of $9 million (2011 – realized losses of $22 million). The Canadian dollar exchange rate strengthened in the third quarter of 2012 which led to unrealized gains on our U.S. dollar denominated long-term debt partially offset by an unrealized loss on our U.S. dollar denominated Partnership Contribution Receivable. For the nine months ended September 30, 2012, we recognized net foreign exchange gains of $42 million (2011 – losses of $56 million) which includes unrealized gain of $82 million (2011 – unrealized loss of $1 million).

DEPRECIATION, DEPLETION and AMORTIZATION

	Three Months Ended September 30,		Nine Months Ended September 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands	**$ 127**	$ 93	**$ 352**	$ 254
Conventional	**222**	195	**680**	575
Refining and Marketing	**36**	20	**109**	54
Corporate and Eliminations	**12**	10	**35**	29
	$ 397	$ 318	**$ 1,176**	$ 912

Oil Sands DD&A for the third quarter of 2012, increased $34 million (year-to-date – $98 million) primarily due to higher sales volumes at Foster Creek, Christina Lake and Pelican Lake as well as increased DD&A rates due to higher future development costs.

DD&A in the Conventional segment increased $27 million in the third quarter of 2012 (year-to-date – $105 million) primarily due to higher crude oil sales volumes and increased DD&A rates due to higher future development costs, partially offset by reduced natural gas sales volumes.

Refining and Marketing DD&A increased $16 million in the third quarter (year-to-date – $55 million) as the capital costs of the CORE project are now subject to depreciation with the coker start-up in the fourth quarter of 2011.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

EXPLORATION EXPENSE

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability has been established are capitalized as E&E assets. If a field, area or project is determined to no longer be technically feasible or commercially viable and we decide not to continue the E&E activity, the unrecoverable costs are charged to exploration expense.

During the nine months ended September 30, 2012, $68 million of capitalized E&E costs, related primarily to the Roncott assets, a small exploration acreage within the Conventional segment, were deemed not to be commercially viable and technically feasible and were recognized as exploration expense.

INCOME TAX EXPENSE

(millions of dollars except percent amounts)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Current tax				
Canada	$ 56	$ 35	$ 139	$ 88
United States	20	1	45	2
Total current tax	76	36	184	90
Deferred tax	110	258	408	551
Income tax expense	$ 186	$ 294	$ 592	$ 641
Effective tax rate	39.2%	36.6%	34.8%	34.6%

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.

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. The effective rate for the current quarter is higher than the year-to-date and the comparative quarter in 2011 due to a change in the weighting of income between our U.S. and Canadian operations.

In the third quarter, current taxes were higher in comparison to 2011 due to increased cash flow from upstream operations taxed at Canadian rates and additional U.S. state income tax from our refining operations. We do not expect to have U.S. federal taxable income as we have sufficient deductions for 2012. Current taxes for the nine months ended September 30, 2012 increased from 2011 as a result of higher cash flow from upstream and refining operations as well as adjustments related to Canadian tax filings.

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

LIQUIDITY AND CAPITAL RESOURCES

(millions of dollars)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net cash from (used in)				
Operating activities	$ 1,029	$ 921	$ 2,662	$ 2,321
Investing activities	(741)	(583)	(2,361)	(1,859)
Net cash provided (used) before Financing activities	288	338	301	462
Financing activities	852	(234)	760	(414)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	(6)	9	(13)	10
Increase (decrease) in cash and cash equivalents	$ 1,134	$ 113	$ 1,048	$ 58

OPERATING ACTIVITIES

Cash from operating activities increased $108 million in the third quarter (year-to-date – increase of $341 million) compared to 2011. The third quarter increase was mainly due to the $324 million increase in cash flow, partially offset by the net change in non-cash working capital. The year-to-date increase was mainly due to the $521 million increase in cash flow, partially offset by the net change in non-cash working capital. Cash flow is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $1,534 million at September 30, 2012 compared to $283 million at December 31, 2011. We anticipate that we will continue to meet our payment obligations as they come due.

INVESTING ACTIVITIES

Cash used for investing activities in the third quarter rose $158 million (year-to-date – increase of $502 million) from 2011. The increase is primarily due to higher capital expenditures of $206 million (year-to-date – increase of $595 million). Year-to-date cash used for investing activities was partially offset by an increase in proceeds from the divestiture of assets of $57 million. Capital expenditures are further discussed under Net Capital Investment within the Financial Information section and Capital Investment within the Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend, and then finally to growth capital. In the third quarter of 2012, we paid a dividend of $0.22 per share (2011 – $0.20 per share). Total dividend payments year-to-date were $498 million (2011 – $452 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash from financing activities in the third quarter increased $1,086 million (year-to-date – increase of $1,174 million) resulting from the issuance of US$1.25 billion of senior unsecured notes on August 17, 2012, offset by the repayment of short-term borrowings and increased dividends paid.

Our long-term debt was $4,626 million as at September 30, 2012 and no payments of principal are due until September 2014 (US$800 million). We had cash and cash equivalents of $1,543 million at September 30, 2012. Long-term debt and cash and cash equivalents rose with the issuance of senior unsecured notes in the third quarter.

AVAILABLE SOURCES OF LIQUIDITY

Source of Funds		Amount (millions)	Term
Cash and Cash equivalents	$	1,543	Not applicable
Committed Bank Facility	$	3,000	November 30, 2016
Canadian Base Shelf Prospectus [1]	$	1,500	June 2014
U.S. Base Shelf Prospectus [1]	US$	750	July 2014

[1] Availability is subject to market conditions.

In September 2012, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and reducing both the standby fees to maintain the facility as well as the cost of future borrowings. We also have a commercial paper program which, together with the committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the 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. As at September 30, 2012, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On June 6, 2012, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 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.

On August 17, 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00% due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45% due September 15, 2042. The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness.

As at September 30, 2012, US$750 million remains under our U.S. shelf prospectus. The U.S. shelf prospectus expires in July 2014.

As at September 30, 2012, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capitalization and debt to adjusted EBITDA. We define debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define capitalization as debt plus shareholders' equity. We define trailing 12-month Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position as measures of our overall financial strength.

	September 30, 2012	December 31, 2011
Debt to Capitalization	**31%**	27%
Debt to Adjusted EBITDA (times)	**1.1x**	1.0x

We continue to have long-term targets for 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.

Our debt levels at September 30, 2012 were higher than at December 31, 2011 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter. At the end of the third quarter, our debt to capitalization and debt to adjusted EBITDA metrics, remain at the low end of our long-term target ranges. Additional information regarding our financial metrics and 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 third preferred shares. As at September 30, 2012, approximately 755.8 million common shares were outstanding (December 31, 2011 – 754.5 million common shares) and no preferred shares were outstanding. The increase in common shares in the nine months ended September 30, 2012 was the result of stock option exercises. No other issuance of common shares has occurred in 2012.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

LEGAL PROCEEDINGS

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

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

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk, liquidity risk and cost overruns;
- Operational risks including capital and operating risks, reserves replacement risks and safety and environmental risks; and
- Regulatory risks including regulatory process and approval risks and changes to environmental regulations.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Management monitors our risk strategies to proactively respond to changing economic conditions and to prevent or mitigate risk. 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 managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

For a further discussion of our risk management please see our Annual MD&A for the year ended December 31, 2011. A description of the risks affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2011 (see Additional Information).

FINANCIAL RISKS

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business. These include, but are not limited to, the global economic environment, commodity prices, credit exposure, liquidity risk and changes to foreign exchange and interest rates.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various instruments and agreements to mitigate exposure to commodity price risk volatility. The details of the financial instruments, including any unrealized gains or losses, as of September 30, 2012, are disclosed in the notes to the interim Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps and futures contracts which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient access to cash resources, including our committed credit facility, is maintained to fund capital expenditures.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Our ability to operate, generate cash flows, complete projects and value reserves is subject to capital and operating risks, including continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary regulatory, stakeholder and partner approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents for blending to enable crude oil transport; technology failures; accidents; the availability of skilled labour and reservoir quality.

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and, therefore, our cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or unanticipated environmental disruption. We are committed to safety in our operations and have high regard for the environment and stakeholders.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

REGULATORY RISKS

Our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by our operating and Cenovus-wide groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives.

Environmental Regulation Risk

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

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 emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, 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.

The Canadian federal government is in the process of developing greenhouse gas regulations for the oil and gas sector. Cenovus is engaged through the Canadian Association of Petroleum Producers in informing and negotiating these emerging regulations.

Alberta's Regulatory Framework

On August 22, 2012, the Government of Alberta approved its Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. The LARP came into effect on September 1, 2012.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted, limiting the pace of development due to environmental limits and thresholds that may adversely affect the market price of our securities and the payment of dividends to our shareholders. The areas identified have no direct impact on our strategic plan, our current operations at Foster Creek and Christina Lake, or any of our filed applications.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We believe in the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks. In recognition of our leadership in the area of corporate responsibility, we were named to the Dow Jones Sustainability World Index on September 14, 2012.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy is available on our website at www.cenovus.com.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We will not compromise the health and safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the policy includes reference to emergency response management, investment in efficiency projects, new technologies and research, and support of the principles of the Universal Declaration of Human Rights.

As part of our ongoing commitment to environmental performance, Cenovus and 11 other Canadian oil companies have formed Canada's Oil Sands Innovation Alliance ("COSIA"). COSIA's objective is to enable responsible and sustainable growth of Canada's oil sands while delivering accelerated improvement in environmental performance through collaborative action and innovation. COSIA provides the overarching leadership, planning and accountability to enable such collaboration. Its mandate is to collectively improve the oil sands industry's environmental performance in the key areas of tailings, water, land and greenhouse gases.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. In June 2012, we released our 2011 CR report which can be found on our website at www.cenovus.com. This report was aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

There have been no changes to our critical accounting policies and estimates in 2012. Further information on our critical accounting policies and estimates can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

FUTURE CHANGES IN ACCOUNTING POLICIES

There are no updates to future changes in accounting policies to date in 2012. Further information on future changes in accounting policies can be found in the notes to the Consolidated Financial Statements and Annual MD&A for the year ended December 31, 2011 (see Additional Information).

OUTLOOK

Our strong performance in the third quarter of 2012 takes us another step closer towards realizing our 10 year business plan. We are continuing to target net oil sands production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. To achieve our production targets, additional expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake.

Our outlook is not without challenges, including anticipated volatility in crude oil prices over the next few years. Our crude oil pricing outlook is influenced by the following:

- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. Short-term prices are likely to remain volatile and be impacted by market expectations;
- Brent-WTI differentials are expected to remain at the wide levels seen since early 2011 due to higher than average refinery outages in Midcontinent and Midwest markets. Differentials should narrow considerably over the first half of 2013 as new pipeline capacity is added to move Cushing crude oil to U.S. Gulf Coast markets;
- WCS prices should weaken relative to U.S. Gulf Coast pricing as previous synthetic and Bakken production disruptions are resolved and planned refinery maintenance ramps up. However, the impact on WCS differentials will be lessened since refinery maintenance will have a greater impact on lighter grades of oil and heavy crude should benefit from the pending startup of new coker capacity;
- Growth in rail capacity out of the Bakken is now likely to be higher than previously thought, which should limit the narrowing of WTI-WCS differentials in 2013; and
- Refining margins are projected to stay strong in the fourth quarter as persistent pipeline congestion at Cushing pressures WTI prices and refineries experience above normal maintenance in the Midwest. Margins should begin to soften in 2013 with new pipeline capacity out of Cushing.

For the remainder of 2012, our continuing strategic initiatives and key priorities include:

- Ongoing construction on Christina Lake phase E, with initial production anticipated in the fourth quarter of 2013;
- Improving production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Progressing the Telephone Lake project, including starting the dewatering pilot test in October;
- Obtaining partner approval for our Narrows Lake project, performing additional engineering and starting construction;
- Further increasing conventional crude oil production from developing our tight oil properties and pursuing additional growth opportunities;
- Committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil as part of our marketing strategy to deliver on our production growth;
- Implementing our environmental strategy through business unit specific action plans; and
- Continuing to demonstrate stable and reliable CORE operations at the Wood River Refinery and successfully completing turnarounds at both refineries in the fourth quarter.

We believe our integrated strategy provides stability to our cash flow, allowing us to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Growing oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as

Narrows Lake, Grand Rapids and Telephone Lake, and we have a 100 percent working interest in many of these assets;

- Continuing the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on environmental performance and meaningful dialogue with our stakeholders;
- Assessing the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, as well as new regions focusing on tight oil opportunities;
- Funding growth internally through free cash flow generation including from our established conventional natural gas assets as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core assets with any incremental cash requirements covered by additional debt financing;
- Lowering our commodity price risk profile through refining integration and natural gas as well as a consistent risk management hedging strategy; and
- Maintaining a sustainable dividend with a priority expected to be placed on growing the dividend as part of delivering a solid total shareholder return.

We trust strong operational performance will translate into solid financial performance. Future cash flow must be allocated using a disciplined approached, focusing on the following priorities:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow. We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends are at the sole discretion of the Board and considered quarterly.

Other key challenges we will need to effectively manage to support our growth include access to markets, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

ADVISORY

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively “forward-looking information”) about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as “anticipate”, “believe”, “expect”, “plan”, “forecast”, “target”, “project”, “could”, “focus”, “vision”, “goal”, “proposed”, “scheduled”, “outlook”, “potential”, “may”, “assumed” or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology including technology and procedures to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the estimation of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF/Form 40-F for the year ended December 31, 2011 (see Additional Information).

ABBREVIATIONS

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

Oil and Natural Gas Liquids

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
WTI	West Texas Intermediate
WCS	Western Canadian Select
CDB	Christina Dilbit Blend
TM	Trademark of Cenovus Energy Inc.

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	Gigajoule
CBM	Coal Bed Methane

NON-GAAP MEASURES

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

ADDITIONAL INFORMATION

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

Additional information relating to Cenovus, including our AIF/Form 40-F for the year ended December 31, 2011 and our Annual MD&A for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.