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

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated July 24, 2012, should be read with our unaudited interim Consolidated Financial Statements and accompanying notes for the period ended June 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 June 30, 2012, we had a market capitalization of approximately $24 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. Our average crude oil and NGLs production in the first six months of 2012 was in excess of 156,000 barrels per day and our average natural gas production was in excess of 615 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, with the possibility of production starting in 2016 depending on industry activity and the associated demand for labour and materials.

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, natural gas and NGLs 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 SECOND QUARTER OF 2012

Overall, the second quarter results have met or exceeded our expectations. Our upstream operations have performed well. Refining and Marketing continues to achieve strong financial results, with increased refinery capacity and heavy oil throughput from the CORE project. Our integrated strategy continues to prove valuable as wide differentials for Canadian crude oil are captured in our lower feedstock costs.

OPERATIONAL RESULTS

The second quarter of 2012 was operationally strong as we achieved daily production highs at our Foster Creek and Christina Lake operations. Our average total crude oil and NGLs production in the second quarter increased 28 percent to 155,566 barrels per day compared to 2011, mainly due to production increases from phase C at Christina Lake, Pelican Lake and from our Conventional crude oil and NGLs operations in southern Alberta and Lower Shaunavon and Bakken tight oil plays.

In June, Foster Creek set a new daily gross production record producing over 129,000 barrels per day. Average daily production was 51,740 barrels per day in the quarter including a 14 day scheduled turnaround. Christina Lake achieved a new daily gross production high of over 64,000 barrels per day in June. Average daily production was 28,577 barrels per day in the quarter. The new daily production highs at Foster Creek and Christina Lake were both in excess of their gross nameplate capacity primarily due to efficient plant operation at Foster Creek and the performance of phase C at Christina Lake.

Our phase D expansion at Christina Lake continued to progress with first steam achieved in the second quarter. Startup of phase D will increase Christina Lake's expected gross production capacity by 40,000 barrels per day to a total of 98,000 barrels per day.

Within our Conventional segment, Alberta crude oil and NGLs production was over 30,000 barrels per day, 13 percent higher than 2011. This increase was primarily the result of successful drilling programs. Our Saskatchewan crude oil and NGLs production continued to increase, driven mainly by our Lower Shaunavon and Bakken areas. In the second quarter, Lower Shaunavon and Bakken crude oil and NGLs production averaged 6,252 barrels per day, more than triple from the second quarter of 2011 and total production in Saskatchewan was 22,674 barrels per day.

Our refineries increased refined product output and improved clean product yield as a result of the successful coker start-up of the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery in the fourth quarter of 2011. Testing of the increased refinery capacity and heavy crude oil throughput from the CORE project continued in the second quarter. Our integrated strategy continues to prove valuable as widening price differentials for Canadian crude oil are captured in lower feedstock costs for our U.S. inland refineries.

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

- Christina Lake achieving record daily production, averaging 28,577 barrels per day, more than a threefold increase due to the start of phase C in third quarter of 2011;
- Average crude oil and NGLs production from our Lower Shaunavon and Bakken tight oil plays more than tripling to 6,252 barrels per day. 2011 was negatively impacted by flooding which restricted access to our operations and reduced our average production by approximately 3,100 barrels per day;
- Conventional crude oil and NGLs production in Alberta increasing 13 percent, primarily due to successful drilling programs and fewer weather and access issues which more than offset expected natural declines and minor operational issues;
- Pelican Lake production averaging 22,410 barrels per day, an increase of 15 percent from the second quarter of 2011, as a result of our infill and polymer flood programs. 2011 production was reduced by approximately 2,100 barrels per day as a result of wild fires in the area curtailing production for two weeks;
- Foster Creek production averaging 51,740 barrels per day, an increase of three percent, due to efficient plant operations while also completing a scheduled turnaround;
- Natural gas production decreasing nine percent primarily due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines; and
- Refined product output of 473 thousand barrels per day, an increase of 51 thousand barrels per day primarily as a result of increased throughput attributable to the CORE project coker start-up at the Wood River Refinery.

FINANCIAL RESULTS

Our second quarter financial results benefited from strong refining margins and increases in our crude oil production, which were offset by reduced sales prices for crude oil. Natural gas results were down significantly due to reduced production and decreases in prices. Lower WTI crude oil prices reduced our royalty expense, as the Canadian dollar WTI price is used to calculate the royalty rates for our Oil Sands operations.

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

- Revenues increasing $205 million, or five percent, primarily due to:
    - Refining and Marketing revenues increasing $237 million due to improved refinery throughput;
    - Crude oil and NGLs sales volumes increasing 27 percent;
    - Increased condensate volumes used for blending partially offset by lower condensate prices;

  Partially offsetting these increases were:
    - Crude oil and NGLs average sales prices (excluding financial hedging) decreasing 19 percent; and
    - Natural gas revenues decreasing $117 million due to decreased production and lower average sales prices.
- Operating cash flow of $351 million from Refining and Marketing, increasing $26 million, primarily due to higher throughput as heavy crude oil processing capacity increased as a result of the coker start-up of the CORE project at the Wood River Refinery. The ability to process a greater proportion of discounted heavy crude oil and improved crack spreads also contributed to higher refining margins;
- Operating cash flow of $727 million from our upstream operations, decreasing $12 million, mainly due to lower crude oil sales prices, decreased natural gas production and prices and increased operating costs, partially offset by increased crude oil production and realized gains on risk management;
- Cash flow of $925 million, decreasing one percent, primarily due to decreased crude oil and natural gas sales prices and increased operating costs from our crude oil and NGLs operations consistent with the increases in our production mostly offset by increased crude oil and NGLs sales volumes and increased operating cash flow from Refining and Marketing;
- Operating earnings decreasing 28 percent to $283 million, primarily due to higher operating cash flow being more than offset by increased depreciation, depletion and amortization ("DD&A") and exploration expense and decreased income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Capital investment of $660 million focused 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 $105 million of operating cash flow in excess of the related capital investment (a decrease of $53 million), used to partially fund the further development of our crude oil projects; 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)]

	Six Months Ended June 30		Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
	2012	2011	**2012**	2012	2011	2011	2011	2011	2010	2010	2010
Crude Oil Prices *(US$/bbl)*											
Brent Futures (ICE)											
Average	**113.61**	111.25	**108.76**	118.45	109.02	112.09	116.99	105.52	87.45	76.96	79.41
End of period	**97.80**	112.48	**97.80**	122.88	107.38	102.76	112.48	117.36	94.75	82.31	75.01
West Texas Intermediate (WTI)											
Average	**98.15**	98.50	**93.35**	103.03	94.06	89.54	102.34	94.60	85.24	76.21	78.05
End of period	**84.96**	95.42	**84.96**	103.02	98.83	79.20	95.42	106.72	91.38	79.97	75.63
Average Differential Brent Futures (ICE)-WTI	**15.46**	12.75	**15.41**	15.42	14.96	22.55	14.65	10.92	2.21	0.75	1.36
Western Canadian Select (WCS)											
Average	**76.01**	78.25	**70.48**	81.61	83.58	71.92	84.70	71.74	67.12	60.56	63.96
End of period	**58.34**	75.32	**58.34**	79.52	84.37	69.38	75.32	91.37	72.87	64.97	61.38
Average Differential WTI-WCS	**22.14**	20.25	**22.87**	21.42	10.48	17.62	17.64	22.86	18.12	15.65	14.09
Average Condensate (C5 @ Edmonton)	**104.70**	105.65	**99.32**	110.16	108.74	101.48	112.33	98.90	85.24	74.53	82.87
Average Differential WTI-Condensate (premium)/discount	**(6.55)**	(7.15)	**(5.97)**	(7.13)	(14.68)	(11.94)	(9.99)	(4.30)	-	1.68	(4.82)
Refining Margin 3-2-1 Average Crack Spreads[(2)] *(US$/bbl)*											
Chicago	**23.60**	22.81	**28.20**	19.00	19.23	33.35	29.00	16.62	9.25	10.34	11.60
Midwest Combined (Group 3)	**24.89**	23.12	**28.28**	21.50	20.75	34.04	27.19	19.04	9.12	10.60	11.38
Natural Gas Average Prices											
AECO *($/GJ)*	**2.06**	3.56	**1.74**	2.39	3.29	3.53	3.54	3.58	3.39	3.52	3.66
NYMEX *(US$/MMBtu)*	**2.48**	4.21	**2.22**	2.74	3.55	4.19	4.31	4.11	3.80	4.38	4.09
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.30**	0.36	**0.39**	0.21	0.17	0.34	0.42	0.29	0.28	0.78	0.32
U.S./Canadian Dollar Exchange Rate											
Average	**0.994**	1.024	**0.990**	0.999	0.978	1.020	1.033	1.015	0.987	0.962	0.973

(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.

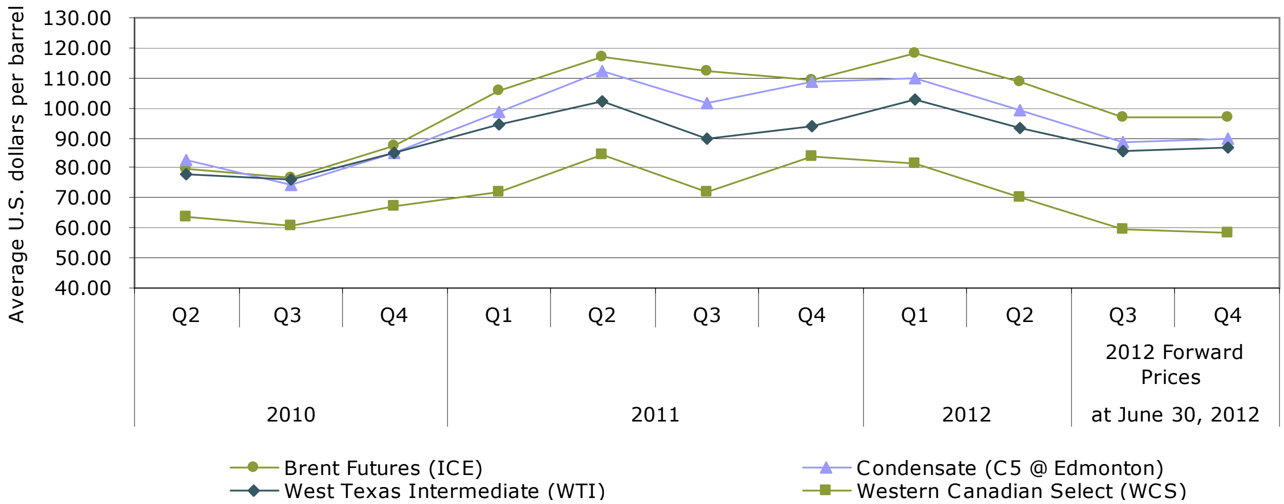
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel.

Crude Oil Benchmarks

The Brent benchmark is representative of global tidewater crude oil prices and is also a better marker for inland refined product price changes than WTI since inland product prices remain tied to global markets. The average price of Brent crude, which had been building throughout the first four months of 2012, decreased sharply in May 2012 primarily due to rising uncertainty over global economic growth, mainly in Europe, China and the United States. Brent prices also decreased in response to rising global crude oil production as significantly higher OPEC production more than offset production outages in Syria, Sudan, Yemen and the North Sea.

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. In June 2012, WTI dropped to under US$80.00 per barrel, its lowest level in 2012 and the first time this has occurred since October 2011, mainly due to mounting concerns that the European debt problems may result in another credit crisis, slowed growth in the Chinese economy and a reduced pace of U.S. job growth. Although WTI has recovered somewhat to the end of June, WTI ended the second quarter US$18.06 per barrel lower than the first quarter of 2012 and almost US$14.00 per barrel lower than the end of 2011. With the second quarter decrease in WTI prices, global demand for the remainder of 2012 and into 2013 is expected to improve.

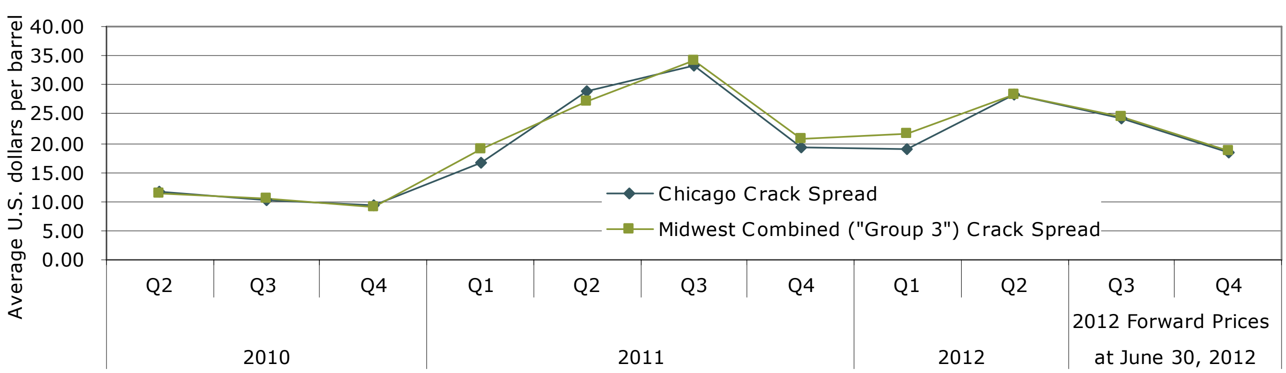
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark, WTI. The WTI-WCS average differential widened slightly in the second quarter of 2012 from the first quarter, primarily due to the continued growth in Canadian heavy and Bakken light crude oil supplies despite significant outages of synthetic crude production due to upgrader problems. Since the supply outages were predominantly light crude, the effects of growing congestion fell primarily on heavy crude differentials.



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. The WTI discounts to offshore light crude oils (including Brent) began to decrease in the second quarter and condensate premiums to WTI narrowed compared to the same period in 2011. The condensate premiums decreased in the second quarter, in part, due to a growing surplus of condensate supply coming mostly from the Texas Eagleford basin as well as the strengthening of WTI prices relative to all U.S. Gulf Coast prices. This relative strengthening of WTI crude was primarily due to the reversal of the Seaway Pipeline in the middle of May and anticipation of further improvements in access to the U.S. Gulf Coast market.

Refining 3-2-1 Crack Spread Benchmarks

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. Average crack spreads in the U.S. inland Chicago and Group 3 markets in the second quarter of 2012 were consistent with the same period in 2011 but substantially improved from the first quarter of 2012. The improved crack spreads resulted from increased inland crude oil discounts.



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.

Other Benchmarks

Natural gas prices in the second quarter of 2012 decreased from already low first quarter levels due to the lingering effects of a very warm winter which materialized in the form of record high storage levels. Natural gas storage balances are steadily improving with lower rig activity resulting in falling supply coupled with steady demand growth. Once storage levels start to approach more normal levels, natural gas prices should improve. Where prices gravitate to will depend in part on the strength of NGL and condensate prices. If congestion continues to plague these markets and prices continue to fall, there will be more room for natural gas prices to rise.

During the second quarter of 2012, the Canadian dollar weakened relative to the U.S. dollar compared to the second quarter of 2011 and the first quarter of 2012. This was due to the same factors which negatively 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)	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Q2 2012	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Revenues	**8,778**	7,509	**4,214**	4,564	4,329	3,858	4,009	3,500	3,363	2,962	3,094
Operating Cash Flow [1]	**2,163**	1,898	**1,078**	1,085	1,019	945	1,064	834	815	661	665
Cash Flow [1]	**1,829**	1,632	**925**	904	851	793	939	693	645	509	537
- per share – diluted	**2.41**	2.15	**1.22**	1.19	1.12	1.05	1.24	0.91	0.85	0.68	0.71
Operating Earnings [1]	**623**	604	**283**	340	332	303	395	209	147	156	143
- per share – diluted	**0.82**	0.80	**0.37**	0.45	0.44	0.40	0.52	0.28	0.19	0.21	0.19
Net Earnings	**822**	702	**396**	426	266	510	655	47	78	295	183
- per share – basic	**1.09**	0.93	**0.52**	0.56	0.35	0.68	0.87	0.06	0.10	0.39	0.24
- per share – diluted	**1.08**	0.93	**0.52**	0.56	0.35	0.67	0.86	0.06	0.10	0.39	0.24
Capital Investment [2]	**1,560**	1,189	**660**	900	903	631	476	713	701	479	444
Cash Dividends	**332**	302	**166**	166	151	150	151	151	151	150	150
- per share	**0.44**	0.40	**0.22**	0.22	0.20	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	Six Months Ended
Revenues for the Periods Ended June 30, 2011	$ 4,009	$ 7,509
Increase (decrease) due to:		
Oil Sands	131	449
Conventional	(113)	(103)
Refining and Marketing	237	947
Corporate and Eliminations	(50)	(24)
Revenues for the Periods Ended June 30, 2012	**$ 4,214**	**$ 8,778**

Oil Sands revenues for the second quarter of 2012 and the six months ended June 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 six months ended June 30, 2012, as higher crude oil production was more than offset by decreased natural gas and crude oil sales prices and lower natural gas production volumes.

Refining and Marketing revenues increased in the three and six months ended June 30, 2012 primarily due to higher refined product volumes. Higher revenues related to operational third party sales undertaken by the marketing group also contributed to the overall revenue increase. The year-to-date increase also benefited from increased refined product prices.

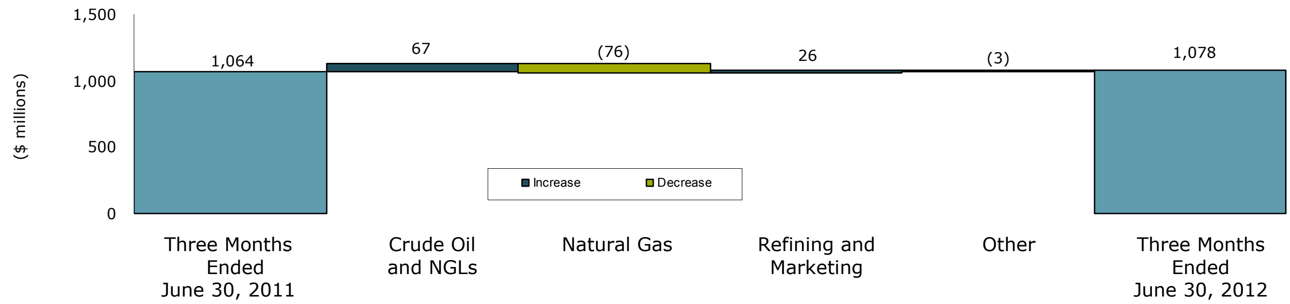
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands				
Crude Oil and NGLs	**$ 378**	$ 321	**$ 795**	$ 571
Natural Gas	**9**	16	**13**	23
Other	**(1)**	2	**(1)**	4
Conventional				
Crude Oil and NGLs	**228**	218	**495**	426
Natural Gas	**112**	181	**240**	366
Other	**1**	1	**3**	3
Refining and Marketing	**351**	325	**618**	505
Operating Cash Flow	**$ 1,078**	$ 1,064	**$ 2,163**	$ 1,898

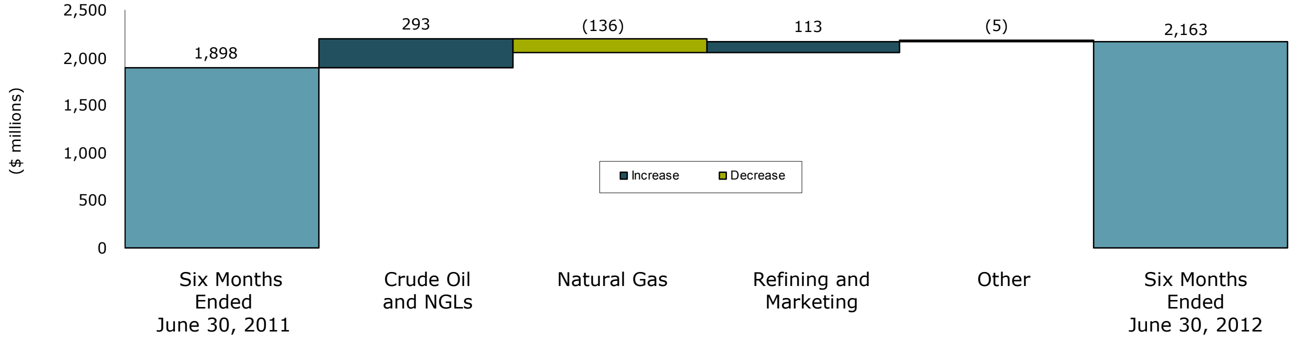
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods. Operating cash flow is defined as revenues less purchased product, transportation 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 June 30, 2012 compared to June 30, 2011



Overall, operating cash flow in the second quarter of 2012 increased $14 million as the $26 million increase from our Refining and Marketing segment was partially offset by the $12 million decrease from our upstream operations. Refining and Marketing operating cash flow increased mainly due to higher throughput volume and the ability to process a greater proportion of discounted heavy crude oil. The increase in operating cash flow from crude oil and NGLs was due to the increased production volumes partially offset by lower average crude oil sales prices and increased operating costs. The $76 million reduction from natural gas was mainly due to decreased average sales prices as well as lower production volumes with the divestiture of a non-core natural gas property in the first quarter of 2012 and expected natural declines.

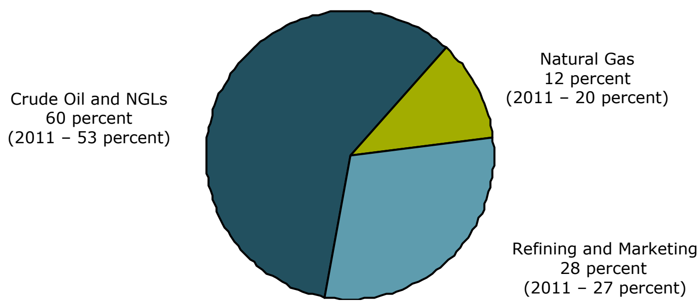
Operating Cash Flow Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Overall, operating cash flow for the six months ended June 30, 2012 increased $265 million as both our upstream operations and Refining and Marketing segment increased from 2011. Refining and Marketing operating cash flow increased mainly due to higher throughput volume, the ability to process a greater proportion of discounted heavy crude oil and increased refined product prices. The increase in operating cash flow from crude oil and NGLs was primarily due to increased production volumes, partially offset by lower average crude oil sales prices and increased operating costs. The $136 million reduction from natural gas was mainly due to decreased average sales prices as well as lower production volumes with the divestiture of a non-core natural gas property in the first quarter of 2012 and expected natural declines.

Operating Cash Flow of $2,163 million for the Six Months Ended June 30, 2012

Crude oil and NGLs generated $1,290 million or 60 percent of our operating cash flow for the six months ended June 30, 2012, up 29 percent from 2011. Operating cash flow generated by Refining and Marketing increased to 28 percent. Natural gas operating cash flow decreased to 12 percent.



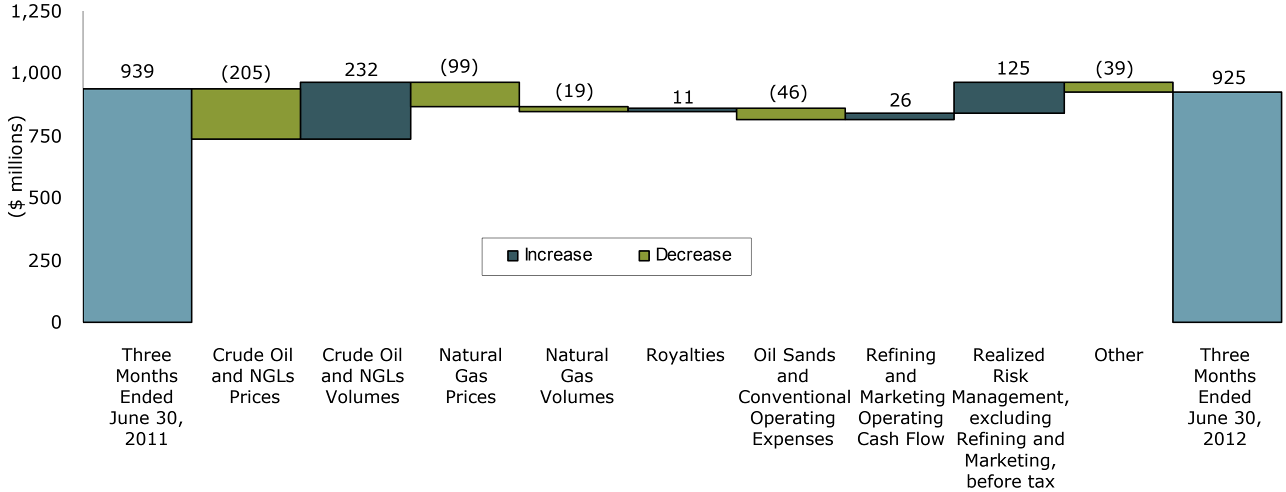
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash From Operating Activities	**$ 968**	$ 769	**$ 1,633**	$ 1,400
(Add back) deduct:				
Net change in other assets and liabilities	**(20)**	(16)	**(52)**	(45)
Net change in non-cash working capital	**63**	(154)	**(144)**	(187)
Cash Flow	**$ 925**	$ 939	**$ 1,829**	$ 1,632

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 June 30, 2012 compared to June 30, 2011



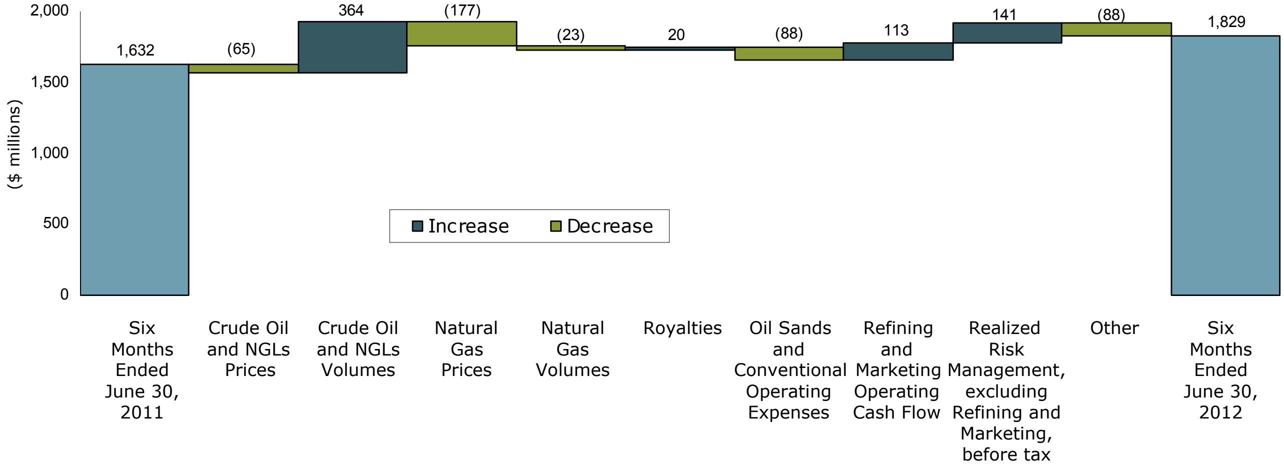
In the second quarter of 2012 our cash flow decreased $14 million primarily due to:

- A 19 percent decrease in the average sales price of crude oil and NGLs to $63.92 per barrel;
- A 48 percent decrease in the average natural gas sales price to $1.92 per Mcf;
- Increased operating expenses, primarily from crude oil and NGLs production, due to the significant increase in production from Christina Lake phase C and the Bakken and Lower Shaunavon areas. Operating costs were also higher at Foster Creek and Pelican Lake;
- A $21 million increase in current income tax expense due to adjustments to prior year Canadian tax estimates and higher tax rates associated with increased U.S. based income; and
- Natural gas production declining nine percent, primarily as a result of the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines.

The decreases in our cash flow in the second quarter of 2012 were partially offset by:

- A 27 percent increase in our crude oil and NGLs sales volumes as a result of increased production in all operating areas;
- Realized risk management gains before tax, excluding Refining and Marketing, of $96 million compared to losses of $29 million in the second quarter of 2011;
- An increase in operating cash flow from Refining and Marketing of $26 million, mainly due to higher throughput, as processing capability of discounted heavy crude oil increased subsequent to coker start-up of the CORE project at the Wood River Refinery in late 2011 and contributed to continuing favourable refining margins; and
- A decrease in royalties of $11 million primarily as a result of the decrease in crude oil prices and increased capital investment at Foster Creek and Pelican Lake. The second quarter of 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.

Cash Flow Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



In the first six months of 2012 our cash flow increased $197 million primarily due to:

- A 21 percent increase in our crude oil and NGLs sales volumes as a result of increased production in all operating areas;
- Realized risk management gains before tax, excluding Refining and Marketing, of $131 million compared to losses of $10 million in 2011;
- An increase in operating cash flow from Refining and Marketing of $113 million, mainly due to higher throughput, as processing capability of discounted heavy crude oil increased subsequent to coker start-up of the CORE project at the Wood River Refinery in late 2011 and continuing favourable refining margins; and
- A decrease in royalties of $20 million primarily as a result of decreased WTI prices and increased capital investment at Foster Creek and Pelican Lake. 2011 included 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 first half of 2012 were partially offset by:

- A 41 percent decrease in the average natural gas sales price to $2.22 per Mcf;
- Increased operating expenses, primarily from crude oil and NGLs production, relating to the significant increase in production from Christina Lake phase C and from the Bakken and Lower Shaunavon areas. Operating costs were also higher at Foster Creek and Pelican Lake;
- A three percent decrease in the average sales price of crude oil and NGLs to $69.26 per barrel;
- A $54 million increase in current income tax expense due to adjustments to prior year Canadian tax estimates and higher tax rates associated with increased U.S. based income; and
- Natural gas production declining six percent, primarily as a result of the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines.

OPERATING EARNINGS

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Net Earnings	**$ 396**	$ 655	**$ 822**	$ 702
(Add back) deduct:				
Unrealized risk management gains (losses), after-tax [(1)]	**126**	232	**174**	31
Non-operating foreign exchange gains (losses), after-tax [(2)]	**(14)**	26	**24**	65
Gain (loss) on divestiture of assets, after-tax	**1**	2	**1**	2
Operating Earnings	**$ 283**	$ 395	**$ 623**	$ 604

(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 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.

The decrease in operating earnings in the second quarter of 2012 is primarily due to the increase in operating cash flow being more than offset by increased DD&A and exploration expense and decreased income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

The increase in operating earnings for the six months ended June 30, 2012 is due to higher operating cash flow and decreased general and administrative expense due to lower long-term incentive costs, partially offset by higher DD&A and exploration expense and increased 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	Six Months Ended
Net Earnings for the Periods Ended June 30, 2011	$ 655	$ 702
Increase (decrease) due to:		
Operating Cash Flow	14	265
Corporate and Eliminations		
Unrealized risk management gains (losses), net of tax	(106)	143
Unrealized foreign exchange gains (losses)	(35)	(40)
Gain on divestitures	(2)	(2)
Expenses [1]	(6)	17
Depreciation, depletion and amortization	(91)	(185)
Exploration expense	(68)	(68)
Income taxes, excluding income taxes on unrealized risk management gains (losses)	35	(10)
Net Earnings for the Periods Ended June 30, 2012	**$ 396**	**$ 822**

[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 second quarter of 2012, our net earnings decreased $259 million compared to the second quarter of 2011. Significant factors that impacted our net earnings in the second quarter of 2012 include:

- Increased operating cash flow as discussed above;
- Unrealized risk management gains, after-tax, of $126 million, compared to gains of $232 million in the second quarter of 2011;
- An increase of $91 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;
- Exploration expense of $68 million;
- Unrealized foreign exchange losses of $9 million compared to gains of $26 million in the second quarter of 2011, consistent with the weakening of the Canadian dollar exchange rate at June 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;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, decreasing to $195 million, compared to $230 million for the same period in 2011; and
- An increase of $2 million for general and administrative expenses primarily due to increased staffing and support costs.

In the six months ended June 30, 2012, our net earnings increased $120 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 gains, after-tax, of $174 million, compared to gains of $31 million in 2011;
- Unrealized foreign exchange gains of $22 million compared to gains of $62 million in 2011, consistent with the weakening of the Canadian dollar exchange rate at June 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 $185 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;
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $347 million, compared to $337 million for the same period in 2011; and
- A decrease of $18 million for general and administrative expenses primarily due to decreased long-term incentive expense partially offset by increased staffing and support costs.

NET CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Oil Sands	**$ 454**	$ 240	**$ 1,090**	$ 644
Conventional	**129**	89	**360**	265
Refining and Marketing	**24**	117	**22**	219
Corporate	**53**	30	**88**	61
Capital Investment	**660**	476	**1,560**	1,189
Acquisitions	**28**	2	**36**	21
Divestitures	**1**	(5)	**(65)**	(9)
Net Capital Investment (1)	**$ 689**	$ 473	**$ 1,531**	$ 1,201

(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 six months ended June 30, 2012 increased compared to 2011 primarily due to higher spending on offsite module assembly and facility construction for phase F, piling work, offsite 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 facility construction for expansion phases D and E as well as phase F site preparation, engineering and equipment purchases. Pelican Lake capital investment included infill drilling for expansion of the polymer flooding, facility expansion, pipeline construction and maintenance. Capital investment in 2012 includes the drilling of 419 gross stratigraphic test wells, down from the 440 gross wells drilled during the first half of 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 six months ended June 30, 2012 was primarily focused 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 tight oil focused drilling in Alberta. The significant increase in capital (second quarter – $40 million; year-to-date – $95 million) reflects the lower capital investment in 2011 due to significant flooding which restricted access to our properties. Our Conventional capital investment 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 six months ended June 30, 2012 was primarily focused on reliability and maintenance 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 in the second quarter 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 June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Cash Flow	**$ 925**	$ 939	**$ 1,829**	$ 1,632
Capital Investment (Committed and Growth)	**660**	476	**1,560**	1,189
Free Cash Flow [1]	**265**	463	**269**	443
Dividends paid	**166**	151	**332**	302
	$ 99	$ 312	**$ (63)**	$ 141

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

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The 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 and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. This program increases cash flow certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

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 affects 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 June 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ 26**	**$ 261**	**$ 287**	$ (70)	$ 325	$ 255
Natural Gas	**75**	**(97)**	**(22)**	45	(16)	29
Refining	**17**	**5**	**22**	(8)	(2)	(10)
Power	**(2)**	**-**	**(2)**	(4)	2	(2)
Gains (Losses) on Risk Management	**116**	**169**	**285**	(37)	309	272
Income Tax Expense (Recovery)	**32**	**43**	**75**	(11)	77	66
Gains (Losses) on Risk Management, after-tax	**$ 84**	**$ 126**	**$ 210**	$ (26)	$ 232	$ 206

In the second quarter of 2012, our risk management strategy resulted in realized gains on our crude oil and natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and decreased WTI benchmark crude oil prices which ended the second quarter of 2012 at a lower average price than the same period in 2011. We also recorded unrealized gains on our crude oil financial instruments as a result of the decrease in forward crude oil commodity prices and unrealized losses on our natural gas financial instruments as a result of increased forward natural gas prices at the end of the second quarter. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

	Six Months Ended June 30,					
	2012			2011		
(millions of dollars)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**$ -**	**$ 291**	**$ 291**	$ (104)	$ 65	$ (39)
Natural Gas	**135**	**(61)**	**74**	97	(49)	48
Refining	**12**	**8**	**20**	(13)	1	(12)
Power	**(2)**	**(5)**	**(7)**	(3)	24	21
Gains (Losses) on Risk Management	**145**	**233**	**378**	(23)	41	18
Income Tax Expense (Recovery)	**38**	**59**	**97**	(8)	10	2
Gains (Losses) on Risk Management, after-tax	**$ 107**	**$ 174**	**$ 281**	$ (15)	$ 31	$ 16

For the six months ended June 30, 2012, our risk management strategy resulted in realized gains on our natural gas financial instruments, consistent with our contract prices compared to the current business environment of low benchmark natural gas prices. We also recorded unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices at June 30, 2012 compared to our market prices at December 31, 2011 and unrealized losses on our natural gas financial instruments as a result of changes in forward commodity prices at June 30, 2012 compared to our market prices at December 31, 2011. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL and NGLs PRODUCTION VOLUMES

(barrels per day)	**Q2 2012**	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Oil Sands									
Foster Creek	**51,740**	57,214	55,045	56,322	50,373	57,744	52,183	50,269	51,010
Christina Lake	**28,577**	24,733	19,531	10,067	7,880	9,084	8,606	7,838	7,716
Pelican Lake	**22,410**	20,730	20,558	20,363	19,427	21,360	21,738	23,259	23,319
Conventional									
Heavy Oil	**15,703**	16,624	15,512	15,305	15,378	16,447	16,553	16,921	16,205
Light & Medium Oil	**36,149**	36,411	32,530	30,399	27,617	31,539	29,323	28,608	29,150
NGLs [1]	**987**	1,138	1,097	1,040	1,087	1,181	1,190	1,172	1,166
	155,566	156,850	144,273	133,496	121,762	137,355	129,593	128,067	128,566

[1] NGLs include condensate volumes.

For the second quarter of 2012, our total crude oil and NGLs production increased 28 percent compared to 2011 primarily due to the start up of Christina Lake phase C in the third quarter of 2011, increased production from our Conventional tight oil operations and higher production at Pelican Lake as a result of our infill drilling and polymer flood program. We have also effectively managed the natural declines to our Conventional heavy oil production. Pelican Lake production in the second quarter of 2011 was reduced by approximately 2,100 barrels per day (year to date – 1,000 barrels per day) due to wild fires which resulted in a two week curtailment of production. Foster Creek maintained steady operations, including the completion of a two week turnaround. Conventional production in the second quarter of 2011 was negatively impacted by wet weather in southern Alberta and Saskatchewan which limited access to our leases. For the six months ended June 30, 2012, our total crude oil and NGLs production increased 21 percent to 156,206 barrels per day (2011 – 129,516 barrels per day). The same factors that impacted the second quarter also impacted our production for the six months ended June 30, 2012. Further discussion on our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	**Q2 2012**	Q1 2012	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Q4 2010	Q3 2010	Q2 2010
Conventional	**563**	595	622	617	617	620	649	694	705
Oil Sands	**33**	41	38	39	37	32	39	44	46
	596	636	660	656	654	652	688	738	751

The 58 MMcf per day decrease in our natural gas production in the second quarter of 2012 compared to 2011 was primarily due to the divesture of a non-core property early in the first quarter of 2012. Excluding the divestiture, our natural gas production would have decreased five percent mainly due to expected natural declines. For the six months ended June 30, 2012 our natural gas production decreased 38 MMcf per day to 616 MMcf per day (2011 – 654 MMcf per day). The decrease was primarily due to the factors that affected our production in the quarter, partially offset by improved weather conditions in 2012. Excluding the impact of the first quarter divestiture, our natural gas production decreased three 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 June 30,			
	2012		2011	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [(1)]	**$ 63.92**	**$ 1.92**	$ 78.72	$ 3.71
Royalties	**4.67**	**0.01**	6.72	0.04
Transportation and blending [(1)]	**2.82**	**0.08**	2.33	0.14
Operating expenses	**13.93**	**0.98**	13.13	0.98
Production and mineral taxes	**0.57**	**0.02**	0.67	0.05
Netback excluding Realized Risk Management	**41.93**	**0.83**	55.87	2.50
Realized Risk Management Gains (Losses)	**1.64**	**1.39**	(6.44)	0.74
Netback including Realized Risk Management	**$ 43.57**	**$ 2.22**	$ 49.43	$ 3.24

(1) The crude oil and NGLs price and transportation and blending costs exclude $20.85 per barrel (2011 - $26.02 per barrel) of condensate purchases which is blended with heavy crude oil.

In the second quarter of 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $13.94 per barrel from 2011. This decrease was primarily due to decreased sales prices consistent with lower WTI and WCS benchmark prices as well as the Christina Lake Dilbit blend ("CDB") differential to WCS and increased operating expenses primarily due to workovers, higher staffing levels and chemical costs. Transportation and blending costs increased primarily due to higher use of rail capacity partially offset by the utilization of our firm service capacity on the Trans Mountain pipeline system to transport crude oil to Canada's west coast. These decreases to our netback price were partially offset by lower royalties consistent with the decrease in WTI prices and increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.67 per Mcf in the second quarter of 2012 due to lower sales prices partially offset by decreased transportation expenses primarily due to expiring transportation contracts.

	Six Months Ended June 30,			
	2012		2011	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [(1)]	**$ 69.26**	**$ 2.22**	$ 71.56	$ 3.76
Royalties	**6.41**	**0.03**	8.47	0.06
Transportation and blending [(1)]	**2.81**	**0.11**	2.48	0.16
Operating expenses	**14.33**	**1.03**	13.29	1.09
Production and mineral taxes	**0.58**	**0.02**	0.50	0.05
Netback excluding Realized Risk Management	**45.13**	**1.03**	46.82	2.40
Realized Risk Management Gains (Losses)	**(0.07)**	**1.20**	(4.41)	0.82
Netback including Realized Risk Management	**$ 45.06**	**$ 2.23**	$ 42.41	$ 3.22

(1) The crude oil and NGLs price and transportation and blending costs exclude $29.07 per barrel (2011 - $25.58 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first six months of 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $1.69 per barrel primarily due to decreased sales prices for Christina Lake due to the CDB differential to WCS. Also decreasing our netback was increased operating expenses primarily due to increased workforce costs, higher workover activity and fluid and waste trucking costs. The increase in transportation and blending costs was primarily due to the use of rail capacity partially offset by the utilization of our firm service capacity on the Trans Mountain pipeline system to transport crude oil to Canada's west coast. The decrease in royalties was primarily due to the decrease in WTI prices and increased capital investment.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.37 per Mcf in the first half of 2012 primarily due to lower sales prices partially offset by decreased operating expenses mainly for workforce, workovers and repairs and maintenance activity as well as 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 second quarter of 2012 include:
- Christina Lake production averaging 28,577 barrels per day, more than a threefold increase, primarily due to production from phase C which began in the third quarter of 2011;
- Christina Lake setting a new daily gross production high of over 64,000 barrels per day, 11 percent above its current gross nameplate production capacity of 58,000 barrels per day;
- Foster Creek setting a new daily gross production high of over 129,000 barrels per day, about eight percent above gross nameplate capacity;
- Completing the scheduled 14 day turnaround at Foster Creek within budget and with a better than expected production impact;
- Foster Creek production averaging 51,740 barrels per day, maintaining steady operations while completing the turnaround;
- Pelican Lake production averaging 22,410 barrels per day, an increase of 15 percent, as a result of our infill and polymer flood programs. The second quarter of 2011 was 2,100 barrels per day lower as wild fires forced the curtailment of production;
- Achieving first steam at Christina Lake phase D; and
- Receiving regulatory approval for our Narrows Lake project.

OIL SANDS - CRUDE OIL

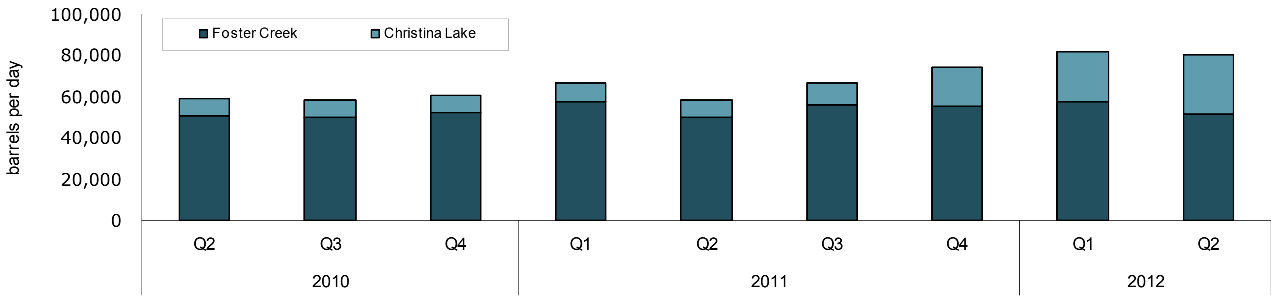
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Gross sales	**$ 909**	$ 766	**$ 1,996**	$ 1,550
Less: Royalties	**26**	25	**91**	107
Revenues	**883**	741	**1,905**	1,443
Expenses				
Transportation and blending	**395**	284	**844**	605
Operating	**125**	91	**263**	198
(Gains) losses on risk management	**(15)**	45	**3**	69
Operating Cash Flow	**378**	321	**795**	571
Capital Investment	**454**	239	**1,085**	629
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (76)**	$ 82	**$ (290)**	$ (58)

Production Volumes

Crude oil (barrels per day)	Three Months Ended June 30, 2012	2012 vs 2011	2011	Six Months Ended June 30, 2012	2012 vs 2011	2011
Foster Creek	**51,740**	**3%**	50,373	**54,477**	**1%**	54,038
Christina Lake	**28,577**	**263%**	7,880	**26,655**	**214%**	8,479
Subtotal	**80,317**	**38%**	58,253	**81,132**	**30%**	62,517
Pelican Lake	**22,410**	**15%**	19,427	**21,570**	**6%**	20,388
	102,727	**32%**	77,680	**102,702**	**24%**	82,905

Foster Creek and Christina Lake Production Volumes by Quarter



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

Revenues Variances

(millions of dollars)	Three Months Ended June 30, 2011	Price	Volume	Royalties	Condensate[1]	Three Months Ended June 30, 2012
	$ 741	(129)	169	(1)	103	**$ 883**

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

In the second quarter, our average crude oil sales price decreased 19 percent to $59.00 per barrel compared to 2011, consistent with the decrease in the WCS benchmark price and the CDB differential to WCS, partially offset by lower condensate costs. Approximately 70 percent of our Christina Lake production is being sold as a new bitumen blend stream, CDB, which is currently priced at a discount to the WCS benchmark. We expect that the CDB differential to WCS will narrow as it gains acceptance with a wider base of refining customers. The remaining Christina Lake production is being sold as part of the WCS stream however, it is subject to a quality equalization charge. In the second quarter, we sold approximately 25 percent of our Christina Lake production as CDB to the Wood River Refinery, further demonstrating our integrated oil strategy and the growing acceptance of CDB by refining customers.

Foster Creek production increased slightly in the second quarter compared to 2011. Production at Foster Creek in the second quarters of both 2012 and 2011 was reduced by approximately 7,400 barrels per day as a result of scheduled turnarounds. The substantial increase in production at Christina Lake was the result of the start-up of phase C in the third quarter of 2011. Pelican Lake production has steadily increased over the last four quarters. Average production in the second quarter of 2012 increased 15 percent from 2011 primarily due to our infill drilling and polymer flood activities partially offset by production shut-ins required to execute infill drilling. Production in the second quarter of 2011 was reduced by wild fires which resulted in a two week curtailment in production. Excluding the impact of wild fires, Pelican Lake production would have increased four percent in the second quarter of 2012.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and an annualized price, volume, allowed operating and capital costs calculation for post-payout projects (Foster Creek and Pelican Lake). Royalties in the three months ended June 30, 2012 were consistent with 2011 as the decrease in forecasted WTI prices for 2012 and increased capital investment at Pelican Lake and Foster Creek were offset by the production increases. Royalties in the second quarter of 2011 include receiving Alberta Department of Energy approval 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 second quarter of 2012 were 4.6 percent at Foster Creek (2011 – 3.3 percent), 7.2 percent at Christina Lake (2011 – 6.3 percent) and 4.2 percent at Pelican Lake (2011 – 9.7 percent).

Transportation and blending costs increased $111 million in the second quarter of 2012. The majority of the increase ($103 million) relates to condensate costs, the result of higher volumes required due to increased production at Christina Lake partially offset by a decrease in the average cost of condensate. Transportation costs increased $8 million primarily as a result of higher Christina Lake production volumes, partially offset by lower transportation charges on the Trans Mountain pipeline system, with our long term commitment for firm service, which commenced in February 2012.

Our operating costs for the second quarter of 2012 were primarily for workforce costs, workovers, chemicals, repairs and maintenance and fuel costs at Foster Creek and Christina Lake. The second quarter also includes costs associated with the scheduled turnaround at Foster Creek. In total, operating costs increased $34 million in the second quarter of 2012 primarily due to a $16 million increase at Christina Lake mainly from the commencement of production of phase C in the third quarter of 2011. On a per barrel basis, Christina Lake operating costs decreased 47 percent to $12.52 per barrel. Operating costs increased $12 million at Pelican Lake due to increased chemical usage, workovers and higher staffing levels. Foster Creek operating costs increased $6 million primarily due to higher staffing levels and increased fluid and waste trucking.

Risk management activities resulted in realized gains of $15 million (2011 – losses of $45 million), consistent with our 2012 contract prices exceeding average benchmark prices in the second quarter of 2012.

Six Months Ended June 30, 2012 compared to June 30, 2011

Revenues Variances

(millions of dollars)	Six Months Ended June 30, 2011	Price	Volume	Royalties	Condensate[1]	**Six Months Ended June 30, 2012**
	$ 1,443	(44)	263	16	227	**$ 1,905**

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

In the first six months of 2012, our average crude oil sales price decreased four percent to $63.83 per barrel compared to 2011, primarily due to the CDB differential to WCS, partially offset by lower condensate costs. To date in 2012, approximately 60 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.

Foster Creek operated as planned with production in the first six months of 2012 increasing slightly as efficient operating of the plant was offset by several power outages and water supply issues. The substantial increase in production at Christina Lake was the result of the start-up of phase C in the third quarter of 2011. Pelican Lake production steadily increased in the first six months of 2012, with average production six percent higher than 2011. These increases were primarily due to production from infill wells brought on production in the second quarter of 2012. 2011 production was reduced by wild fires which curtailed production by approximately 1,000 barrels per day.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and an annualized price, volume, allowed operating and capital costs calculation for post-payout projects (Foster Creek and Pelican Lake). Royalties decreased $16 million in the first six months of 2012 primarily due to lower forecasted WTI prices for 2012 and increased capital investment at Foster Creek and Pelican Lake, partially offset by increased production at all three Oil Sands assets. Royalties were also lower in 2011 after receiving Alberta Department of Energy approval 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 six months ended June 30, 2012 were 9.7 percent at Foster Creek (2011 – 11.9 percent), 7.1 percent at Christina Lake (2011 – 5.6 percent) and 4.4 percent at Pelican Lake (2011 – 11.9 percent).

Transportation and blending costs increased $239 million in the first six months of 2012. The majority of the increase ($227 million) relates to condensate costs, the result of higher volumes required due to increased production at Christina Lake and increases in the average cost of condensate. Transportation costs increased $12 million primarily as a result of higher Christina Lake production volumes, partially offset by lower transportation charges on the Trans Mountain pipeline system, with our long term commitment for firm service, which commenced in February 2012.

Our operating costs for the first six months of 2012 were primarily for workforce costs, workovers, repairs and maintenance, Foster Creek and Christina Lake fuel costs and chemical usage at all three operations. In total, operating costs increased $65 million in the first half of 2012 with $34 million of the increase at Christina Lake mainly due to the commencement of production of phase C in the third quarter of 2011. On a per barrel basis, Christina Lake operating costs decreased 34 percent to $13.84 per barrel due to the increase in production. Operating costs increased $17 million at Pelican Lake due to increased workovers, workforce costs, electricity and chemical costs. Foster Creek operating costs increased $14 million due to higher workover activity, increased workforce costs and higher levels of fluid and waste trucking activity.

Risk management activities resulted in realized losses of $3 million (2011 – losses of $69 million), consistent with average benchmark prices in the first half of 2012 exceeding our 2012 contract prices.

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 33 MMcf per day in the second quarter of 2012 (2011 – 37 MMcf per day) primarily due to expected natural declines partially offset by a reduction in the use of our natural gas production at our Foster Creek operation. Natural gas production increased slightly to 37 MMcf per day for the six months ended June 30, 2012 (2011 – 35 MMcf per day) as the reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues in the first quarter were partially offset by expected natural declines. Lower natural gas prices and production resulted in operating cash flow declining to $9 million for the second quarter of 2012 (2011 – $16 million). Operating cash flow for the six months ended June 30, 2012 declined to $13 million (2011 – $23 million) primarily due to lower natural gas prices partially offset by the increase in production.

OIL SANDS - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Foster Creek	**$ 169**	$ 77	**$ 328**	$ 180
Christina Lake	**138**	121	**265**	229
Subtotal	**307**	198	**593**	409
Pelican Lake	**104**	31	**243**	115
Narrows Lake	**9**	2	**18**	12
Telephone Lake	**13**	4	**104**	31
Grand Rapids	**5**	(5)	**39**	13
Other [1]	**16**	10	**93**	64
Capital Investment [2]	**$ 454**	$ 240	**$ 1,090**	$ 644

[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 offsite module assembly and facility construction, phase G spending on piling work, offsite 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 – 110 wells).

Christina Lake capital investment increased in 2012 compared to 2011 primarily from the phase D and E expansions, for site preparation and facility construction as well as increased capital related to engineering and equipment purchases for phase F. 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 phase C construction in the second quarter of 2011. First steam at phase D was achieved in the second quarter. First production from phase D is expected in the third quarter of 2012 and from phase E in the fourth quarter of 2013. With the completion of phases D and E we expect to increase gross production capacity at Christina Lake to approximately 138,000 barrels per day.

Pelican Lake capital investment for the three and six months ended June 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 boiler 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])	Six Months Ended June 30, 2012	2011
Foster Creek	**11**	8
Christina Lake	**11**	8
Subtotal	**22**	16
Pelican Lake	**29**	6
Grand Rapids	**1**	-
Other	**2**	3
	54	25

[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.

(gross stratigraphic test wells drilled)	Six Months Ended June 30, 2012	2011
Foster Creek	**124**	110
Christina Lake	**28**	59
Subtotal	**152**	169
Pelican Lake	**5**	57
Narrows Lake	**38**	41
Grand Rapids	**41**	38
Telephone Lake	**29**	40
Borealis (including Steepbank)	**48**	44
Other	**106**	51
	419	440

In addition, we drilled 26 observation wells (2011 – nil) in the first six months of 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, natural gas and NGLs 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 second quarter of 2012 include:

- Alberta crude oil and NGLs production averaging 30,165 barrels per day, increasing 13 percent primarily due to successful drilling programs and fewer weather and access issues;
- Average crude oil and NGLs production from our Lower Shaunavon and Bakken tight oil plays more than tripling to 6,252 barrels per day with capital spending focusing on drilling, completions and facilities;
- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $105 million;
- Natural gas production decreasing nine percent to 563 MMcf per day primarily due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines; and
- Maintaining our crude oil focus by increasing crude oil capital investment by 85 percent. We continue to manage natural gas capital investment due to low prices.

CONVENTIONAL - CRUDE OIL and NGLs

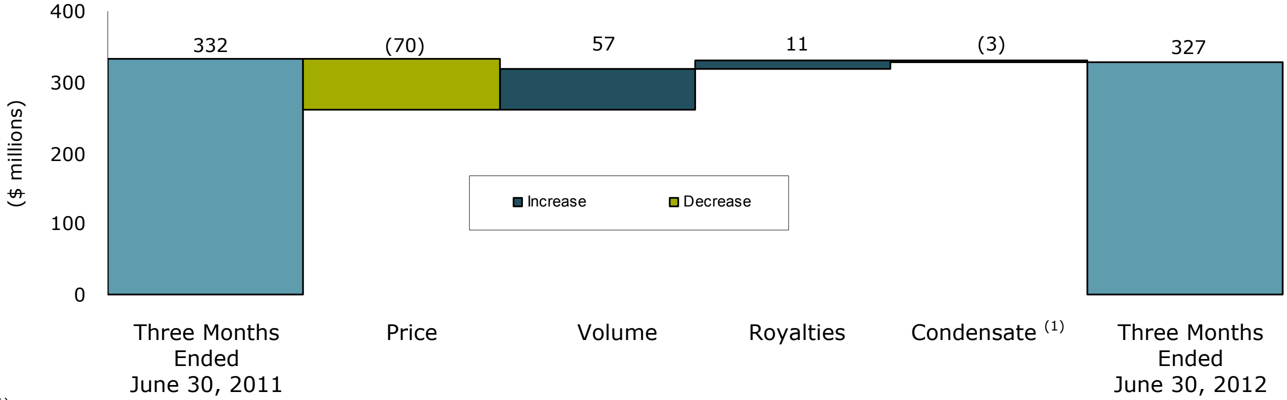
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Gross sales	**$ 365**	$ 381	**$ 819**	$ 737
Less: Royalties	**38**	49	**92**	93
Revenues	**327**	332	**727**	644
Expenses				
Transportation and blending	**31**	28	**69**	55
Operating	**67**	51	**146**	114
Production and mineral taxes	**8**	7	**17**	12
(Gains) losses on risk management	**(7)**	28	**-**	37
Operating Cash Flow	**228**	218	**495**	426
Capital Investment	**122**	66	**338**	219
Operating Cash Flow in Excess of Related Capital Investment	**$ 106**	$ 152	**$ 157**	$ 207

Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
(barrels per day)	**2012**	**2012 vs 2011**	2011	**2012**	**2012 vs 2011**	2011
Heavy Oil						
Alberta	**15,703**	**2%**	15,378	**16,163**	**2%**	15,910
Light and Medium Oil						
Alberta	**13,532**	**32%**	10,289	**13,215**	**22%**	10,804
Saskatchewan	**22,617**	**31%**	17,328	**23,065**	**23%**	18,763
NGLs	**987**	**-9%**	1,087	**1,061**	**-6%**	1,134
	52,839	**20%**	44,082	**53,504**	**15%**	46,611

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

Our average crude oil and NGLs sales price for the second quarter decreased 17 percent to $73.49 per barrel compared to 2011, consistent with the decrease in crude oil benchmark prices.

Our crude oil and NGLs production increased 20 percent in the second quarter as a result of successful capital programs and improved weather conditions in 2012. Crude oil and NGLs production from our Lower Shaunavon and Bakken areas more than tripled from the same period in 2011 to 6,252 barrels per day. In Alberta, production of crude oil and NGLs continued to exceed the daily production milestone of 30,000 barrels per day achieved in the first quarter; second quarter production averaged 30,165 barrels per day.

Royalties decreased by $11 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 June 30, 2012 was 11.7 percent (2011 – 14.5 percent).

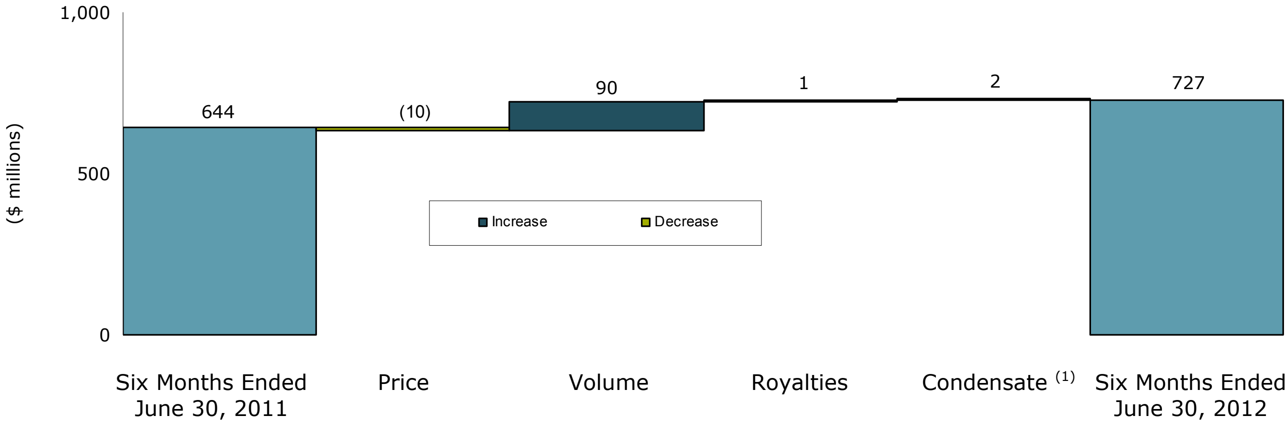
Transportation and blending costs increased $3 million compared to 2011. The condensate portion was a decrease of $3 million due to decreases in the average cost of condensate and volumes required for blending. Transportation costs increased $6 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls and increased costs of accessing new markets, including using rail for our growing Bakken production.

Our primary operating costs components were workover activity, electricity, repairs and maintenance and workforce costs. Operating costs increased $16 million in the second quarter of 2012 primarily due to higher workover activity, increased trucking and waste handling costs, higher repairs and maintenance and increased workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil as well as higher volumes across our conventional crude oil operations.

Risk Management activities for the three months ended June 30, 2012 resulted in realized gains of $7 million (2011 – losses of $28 million) consistent with our 2012 contract prices exceeding the average benchmark prices in the second quarter of 2012.

Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by $46 million in the second quarter of 2012 as the $56 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was partially offset by the $10 million increase in operating cash flow.

Revenues Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Six Months Ended June 30, 2012 compared to June 30, 2011

Our average crude oil and NGLs sales price for the first six months of 2012 decreased slightly to $79.86 per barrel compared to the same period in 2011, consistent with the decrease in crude oil benchmark prices being offset by the weakening Canadian dollar.

Our crude oil and NGLs production increased 15 percent in the first half of 2012 as a result of successful capital programs and improved weather conditions which improved access to our leases in 2012 partially offset by expected natural declines. Production of crude oil and NGLs in Alberta exceeded the daily production milestone of 30,000 barrels per day, averaging 30,382 barrels per day in the first six months of 2012. Average production from our Lower Shaunavon and Bakken areas increased 146 percent from the same period in 2011.

Royalties were consistent 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 six months ended June 30, 2012 was 12.7 percent (2011 – 14.0 percent).

Transportation and blending costs increased $14 million in the first half of 2012 compared to 2011. The condensate portion of the increase was $2 million due to increases in the volumes required for blending, partially offset by decreases in the average cost of condensate. Transportation costs increased $12 million, primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls and increased costs on accessing new markets, including using rail for our growing Bakken production.

Our primary operating costs components were workover activity, trucking and waste handling costs, repairs and maintenance, workforce costs and fuel costs. Operating costs increased $32 million in the first half of 2012 primarily due to higher workover and repairs and maintenance activity, increased trucking and waste handling costs and increased workforce costs. These increases reflect the shift in strategic focus from natural gas to crude oil as well as higher production across our conventional crude oil operations.

Risk Management activities for the six months ended June 30, 2012 resulted in no realized gains or losses (2011 – losses of $37 million).

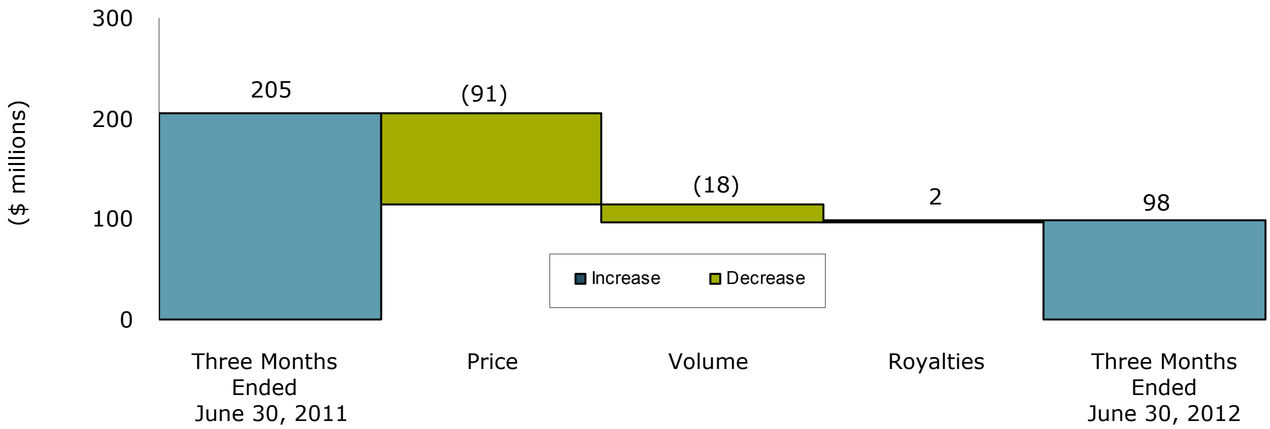
Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by $50 million in the first half of 2012 as the $119 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was partially offset by the $69 million increase in operating cash flow.

CONVENTIONAL - NATURAL GAS

Financial Results

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Gross sales	**$ 99**	$ 208	**$ 234**	$ 422
Less: Royalties	**1**	3	**3**	6
Revenues	**98**	205	**231**	416
Expenses				
Transportation and blending	**5**	8	**11**	18
Operating	**48**	53	**102**	114
Production and mineral taxes	**1**	3	**2**	6
(Gains) losses on risk management	**(68)**	(40)	**(124)**	(88)
Operating Cash Flow	**112**	181	**240**	366
Capital Investment	**7**	23	**22**	46
Operating Cash Flow in Excess of Related Capital Investment	**$ 105**	$ 158	**$ 218**	$ 320

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



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

Our natural gas revenues and operating cash flow were lower in the second quarter, primarily due to decreased average sales prices consistent with the decrease in the benchmark AECO price and lower production. Our natural gas production in the three months ended June 30, 2012 decreased nine percent to 563 MMcf per day, primarily 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 decreased production was a result of expected natural declines. Excluding the impact of the non-core divestiture, our natural gas production would have decreased five percent from the same period in 2011.

Royalties decreased $2 million in the three months ended June 30, 2012 due to lower prices and volumes. The average royalty rate in the second quarter of 2012 was 1.0 percent (2011 – 1.5 percent).

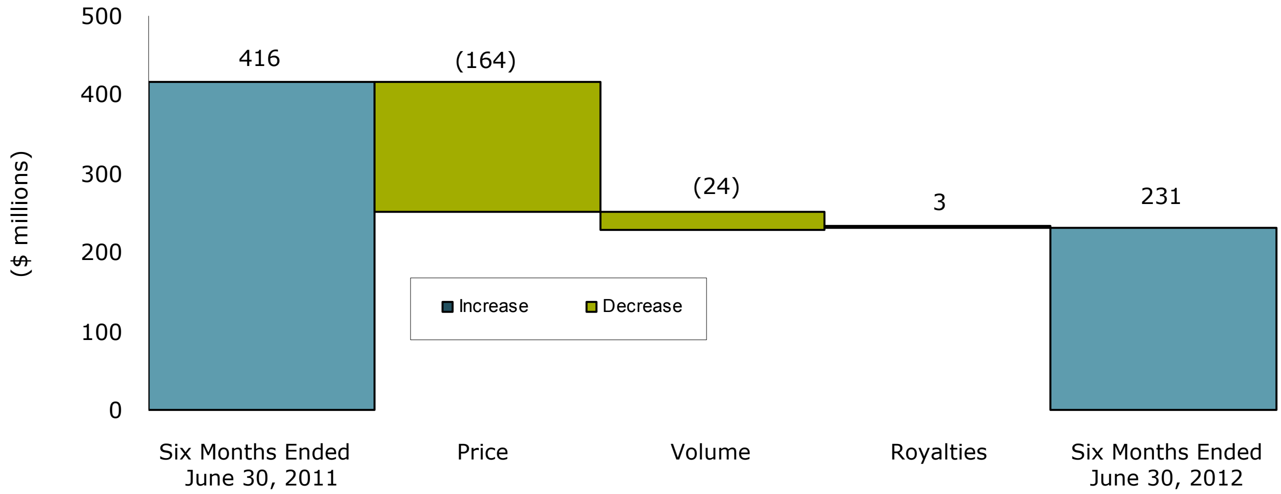
Transportation costs decreased $3 million primarily due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, workforce costs and electricity. Operating expenses decreased $5 million in the second quarter of 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 resulted in lower workforce costs and workover activity. We also had reduced repairs and maintenance activity in response to the low natural gas prices.

Risk management activities for the three months ended June 30, 2012 resulted in realized gains of $68 million (2011 – gains of $40 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 $53 million primarily due to lower average sales prices and production volumes partially offset by a $16 million reduction in capital investment.

Revenues Variance for the Six Months Ended June 30, 2012 compared to June 30, 2011



Six Months Ended June 30, 2012 compared to June 30, 2011

Our natural gas revenues and operating cash flow decreased in the first six months of 2012, primarily due to lower average sales prices consistent with the change in the benchmark AECO price and decreased production. Our natural gas production in the first half of 2012 decreased six percent to 579 MMcf per day, primarily due to the divestiture of a non-core property early in the first quarter of 2012, which reduced production by 19 MMcf per day and expected natural declines. Excluding the impact of the non-core divestiture, our natural gas production would have been three percent lower than the same period in 2011.

Royalties decreased $3 million in the first half of 2012 due to lower prices and volumes. The average royalty rates in the first six months of 2012 and 2011 were 1.4 percent.

Transportation costs decreased $7 million primarily due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, workforce costs and electricity. Operating expenses decreased $12 million in the first six months of 2012. The reduction in natural gas activity and the disposition of a non-core property early in 2012 resulted in lower workforce costs, repairs and maintenance activity, property taxes and lease rental costs and workover activity. We also had reduced electricity costs due to lower prices in 2012.

Risk management activities in the first half of 2012 resulted in realized gains of $124 million (2011 – gains of $88 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 $102 million primarily due to lower average sales prices and production volumes partially offset by a $24 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Crude Oil	**$ 122**	$ 66	**$ 338**	$ 219
Natural Gas	**7**	23	**22**	46
Capital Investment [1]	**$ 129**	$ 89	**$ 360**	$ 265

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

Capital investment in our Conventional segment was focused on crude oil opportunities. Crude oil capital investment in Saskatchewan was focused on facilities work in the Lower Shaunavon and Bakken areas where we completed battery construction at Bakken and progressed facilities construction at Lower Shaunavon, which are expected to be complete in the third quarter of 2012. Capital investment in Saskatchewan also included drilling and facilities work at Weyburn and drilling and completions in the Lower Shaunavon and Bakken areas. Alberta crude oil capital investment was focused on drilling activities. In response to the current natural gas price environment we have reduced spending on natural gas.

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

	Six Months Ended June 30,	
(net wells)	**2012**	2011
Crude oil	**114**	105
Natural gas	**-**	15
Recompletions	**579**	546
Stratigraphic test wells	**7**	3

REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by Phillips 66. Reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of 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 second quarter of 2012 include:

- A significant increase in throughput and refined product output along with the ability to process a greater proportion of heavy crudes resulting from coker start-up of the CORE project at the Wood River Refinery;
- Continuing favourable refining margins, consistent with higher benchmark crack spreads and discounted feedstock costs;
- Operating cash flow increasing $26 million to $351 million primarily due to higher throughput and the ability to process a greater proportion of discounted heavy crude oil which contributed to the improved refining margins; and
- Our refineries processing 451 thousand barrels per day of crude oil resulting in 473 thousand barrels per day of refined product output.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Revenues	**$ 2,962**	$ 2,725	**$ 5,954**	$ 5,007
Purchased product	**2,508**	2,283	**5,097**	4,252
Gross margin	**454**	442	**857**	755
Expenses				
Operating expenses	**123**	109	**253**	237
(Gain) loss on risk management	**(20)**	8	**(14)**	13
Operating Cash Flow	**351**	325	**618**	505
Capital Investment	**24**	117	**22**	219
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 327**	$ 208	**$ 596**	$ 286

The gross margin for Refining and Marketing increased $12 million in the second quarter of 2012 (year-to-date - $102 million) primarily due to increases in crude oil throughput and refined product output with the completion of the CORE project's coker construction at the Wood River Refinery late in 2011. As was the case throughout 2011, refining margins in 2012 have continued to reflect refined product prices tied to global market prices, as well as purchased product costs, which are accounted for on a first-in, first-out basis, that benefit from relative discounts on heavy crude oil and U.S. inland crude oil. The benefit to our refining results in 2012 of discounted purchased product prices demonstrates the effectiveness of our objective to economically integrate our heavy oil production, which has improved as a result of the CORE project.

Total operating costs, consisting mainly of labour, maintenance, utilities and supplies, increased by $14 million in the second quarter of 2012 and increased $16 million for the six months ended June 30, 2012. While there is an increase in utility usage at the Wood River Refinery subsequent to CORE project start-up, utilities expense has declined at both refineries from the same period in 2011 due to significantly lower prices for fuel gas and electricity. This cost reduction was offset by various cost increases including higher labour and maintenance related costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $26 million to $351 million in the second quarter of 2012 and increased $113 million in the first six months of 2012 to $618 million. These increases were primarily due to the utilization of expanded heavy crude oil refining capability attributable to the CORE project and continued favourable refining margins. Capital investment decreased by $93 million in the second quarter of 2012 (year-to-date - $197 million) with the completion of CORE project coker construction at the Wood River Refinery in the fourth quarter of 2011. Also decreasing our year-to-date capital investment were Illinois tax credits related to capital expenditures at the Wood River Refinery in prior periods.

REFINERY OPERATIONS [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	**2012**	2011
Crude oil capacity *(Mbbls/d)*	**452**	452	**452**	452
Crude oil runs *(Mbbls/d)*	**451**	406	**448**	384
Crude utilization *(%)*	**100**	90	**99**	85
Refined products *(Mbbls/d)*	**473**	422	**469**	403

(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 six months ended June 30, 2012 reflect the benefits of start-up of the CORE project in the fourth quarter of 2011, including significant increases in crude oil runs and refined product output. 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. The combined heavy crude oil refining capacity of both refineries is expected to be approximately 235,000 to 255,000 barrels per day. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. In the second quarter the Wood River Refinery purchased for processing approximately 22,000 barrels per day of CDB from our Christina Lake operations further demonstrating our integrated oil strategy and the growing acceptance of CDB by refineries.

REFINING AND MARKETING - CAPITAL INVESTMENT

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Wood River Refinery	**$ 14**	$ 104	**$ 6**	$ 200
Borger Refinery	**10**	12	**16**	18
Marketing	**-**	1	**-**	1
Capital Investment	**$ 24**	$ 117	**$ 22**	$ 219

With the CORE project coker construction now complete, our refining capital investment in 2012 was primarily related to refinery reliability and maintenance projects. Also, in the first quarter of 2012 we recognized Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment for the six months ended June 30, 2012.

CORPORATE AND ELIMINATIONS

Financial Results

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenues	**$ (65)**	$ (15)	**$ (65)**	$ (41)
Expenses ((add)/deduct)				
Purchased product	**(65)**	(15)	**(65)**	(41)
Operating	**-**	1	**(1)**	-
(Gains) losses on risk management	**(169)**	(309)	**(233)**	(41)
	$ 169	$ 308	**$ 234**	$ 41

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
General and administrative	**$ 57**	$ 55	**$ 150**	$ 168
Finance costs	**111**	106	**224**	223
Interest income	**(27)**	(31)	**(56)**	(63)
Foreign exchange (gain) loss, net	**25**	(6)	**9**	(29)
(Gain) loss on divestitures	**(1)**	(3)	**(1)**	(3)
Other (income) loss, net	**1**	1	**(4)**	-
	$ 166	$ 122	**$ 322**	$ 296

General and administrative expenses increased $2 million in the second quarter of 2012 due to increased staffing and support costs. The year-to-date decrease of $18 million was due to lower long-term incentive expense partially offset by increased 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 discount on decommissioning liabilities. In the second quarter, our finance costs were $5 million higher than 2011 (year-to-date – $1 million higher). The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for the second quarter of 2012 was 5.2 percent (2011 – 5.2 percent) and for the six months ended June 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. When compared to the same periods in 2011, interest income for the second quarter of 2012 decreased by $4 million and for the six months ended June 30, 2012 decreased $7 million. These decreases are consistent with lower interest being earned on the partnership contribution receivable as the balance is collected.

In the second quarter, we reported net foreign exchange losses of $25 million (2011 – gains of $6 million), which includes unrealized losses of $9 million (2011 – unrealized gains of $26 million) and realized losses of $16 million (2011 – realized losses of $20 million). The Canadian dollar exchange rate weakened in the second quarter of 2012 which led to unrealized losses on our U.S. dollar denominated long-term debt partially offset by unrealized gains on our U.S. dollar denominated partnership contribution receivable. For the six months ended June 30, 2012, we recognized net foreign exchange losses of $9 million (2011 – gain of $29 million) which includes unrealized gains of $22 million (2011 – unrealized gains of $62 million).

DEPRECIATION, DEPLETION and AMORTIZATION

(millions of dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Oil Sands	**$ 110**	$ 75	**$ 225**	$ 161
Conventional	**222**	185	**458**	380
Refining and Marketing	**35**	18	**73**	34
Corporate and Eliminations	**12**	10	**23**	19
	$ 379	$ 288	**$ 779**	$ 594

Oil Sands DD&A for the second quarter of 2012, increased $35 million (year-to-date – $64 million) primarily due to higher sales volumes at Christina Lake and Pelican Lake and increased DD&A rates due to higher future development costs.

DD&A in the Conventional segment increased $37 million in the second quarter of 2012 (year-to-date – $78 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 including the disposition of a non-core asset.

Refining and Marketing DD&A increased $17 million in the second quarter (year-to-date – $39 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 second quarter of 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Current tax				
Canada	**$ 21**	$ 12	**$ 83**	$ 53
United States	**13**	1	**25**	1
Total current tax	**34**	13	**108**	54
Deferred tax	**204**	294	**298**	293
Income tax expense	**$ 238**	$ 307	**$ 406**	$ 347
Effective tax rate	**37.5%**	31.9%	**33.1%**	33.1%

When comparing the three months ended June 30, 2012 to 2011, our current tax expense increased and our deferred tax expense decreased. The current tax increase is primarily due to the true up of estimated 2011 tax and higher U.S. state income tax offset by higher tax pool claims. The decrease in deferred tax is due to a decrease in income from our upstream operations and lower unrealized risk management gains, partially offset by an increase in income from our Refining and Marketing operations.

When comparing the six months ended June 30, 2012 to 2011, both our current and deferred expense increased. The current tax increase is primarily due to the true up of estimated 2011 tax and higher U.S. state income tax. The increase in deferred tax is primarily due to an increase in income from our Refining and Marketing operations and higher unrealized risk management gains partially offset by the reversal of certain timing differences.

The U.S. current tax in 2012 reflects state income tax. We expect to have sufficient deductions to shelter our U.S. federal taxable income for 2012.

Our effective tax rate reflects income in Canada and the U.S. at their relevant statutory tax rates. The effective tax rate for the second quarter of 2012 includes Canadian tax adjustments related to prior year estimates.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns.

Permanent differences include:
- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions of dollars)	**2012**	2011	**2012**	2011
Net cash from (used in)				
Operating activities	**$ 968**	$ 769	**$ 1,633**	$ 1,400
Investing activities	**(788)**	(592)	**(1,620)**	(1,276)
Net cash provided (used) before Financing activities	**180**	177	**13**	124
Financing activities	**(230)**	(310)	**(92)**	(180)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(1)**	(1)	**(7)**	1
Increase (decrease) in cash and cash equivalents	**$ (51)**	$ (134)	**$ (86)**	$ (55)

OPERATING ACTIVITIES

Cash from operating activities increased $199 million in the second quarter (year-to-date – increase of $233 million) compared to 2011. The second quarter increase was mainly due to the net change in non-cash working capital partially offset by the $14 million decrease in cash flow. The year-to-date increase was mainly due to the $197 million increase in cash flow. 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 $215 million at June 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 second quarter increased $196 million (year-to-date – increase of $344 million) from 2011. The increase is primarily due to higher capital expenditures of $210 million (year-to-date – increase of $389 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 second quarter of 2012, we paid a dividend of $0.22 per share (2011 – $0.20 per share). Total dividend payments year-to-date were $332 million (2011 – $302 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in the second quarter decreased $80 million (year-to-date – decrease of $88 million) from 2011. The second quarter decrease was due to lower repayments of short-term borrowings partially offset by increased dividends paid. The year-to-date decrease was primarily due to increased issuance of short-term borrowings partially offset by increased dividends paid.

Our long-term debt was $3,536 million as at June 30, 2012 and no payments of principal are due until September 2014 (US$800 million). We had short-term borrowings of $209 million under our commercial paper program and we also had cash resources of $409 million, the majority of which was held by joint operations.

AVAILABLE SOURCES OF LIQUIDITY

Source of Funds		Amount	Term
Cash and Cash equivalents	$	409	Not applicable
Committed Bank Facilities	$	3,000	November 30, 2015
Canadian Base Shelf Prospectus [1]	$	1,500	June 2014
U.S. Base Shelf Prospectus [1]	US$	2,000	July 2014

[1] Availability is subject to market conditions.

We have a $3.0 billion committed credit facility with a maturity date of November 30, 2015 and a commercial paper program, both of which are used to manage our short-term cash requirements. At June 30, 2012, we had $209 million of short-term borrowings (December 31, 2011 – nil) in the form of commercial paper. 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 June 30, 2012, no medium term notes have been issued under this Canadian prospectus. The 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. As at June 30, 2012, no notes have been issued under this U.S. prospectus. The shelf prospectus expires July 2014.

As at June 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.

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

At June 30, 2012, our financial position remained consistent with the end of 2011 as measured by our debt to capitalization and debt to adjusted EBITDA metrics, both of which remain at or below 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 second preferred shares. As at June 30, 2012, approximately 755.7 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 first six months of 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 financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of June 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

In 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act and awaits provincial cabinet approval prior to being implemented. The timeline for implementation is unclear as there has been no visible progress on this framework in 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. If the land use designations for conservation, tourism and recreation areas are approved in their current form, 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 recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy 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 in the first six months of 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 outlook is dependant on several factors including commodity prices and the effect of new market access for North American crude oil. Crude oil prices for the remainder of 2012 are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

The average price of Brent crude, which had been building throughout the first four months of 2012, decreased sharply in May 2012 and is not expected to reach its previous high for the remainder of the year. The decrease in Brent prices was primarily due to rising uncertainty over global economic growth, mainly in Europe, China and the United States. Increased global crude oil production, primarily from OPEC countries, more than offset production outages from Syria, Sudan and Yemen, lowering the average Brent price. With very strong levels of output, Saudi Arabia is in good position to defend prices in the event of any significant further weakness in markets.

The WTI price discount to Brent, which started the year wider than in 2011, is expected to continue to narrow through the remainder of 2012 with the addition of pipeline capacity from Cushing, Oklahoma to the U.S. Gulf Coast in May 2012 and as further capacity is incrementally added. With this capacity added, WTI is expected to be just below parity with Brent prices by the end of the first quarter of 2013.

In the second quarter of 2012, the WTI-WCS differential widened further as the continued growth of inland crude oil supply increased pipeline congestion. This was only partially offset by higher demand from U.S. Midwest refineries as a result of strengthening cracking margins. With supply growth expected to continue and only minimal increases in pipeline and rail capacity, there should be a continued widening of Canadian differentials including WCS. The widening of the WTI-WCS differential was also impacted by the commissioning of the Seaway Pipeline reversal which provided some relief for Cushing crude, including WTI, but has provided minimal benefits for Canadian crude oil.

Increased refined product crack spreads and decreased heavy oil feedstock costs in the second quarter of 2012 resulted in improved economics for U.S. Midwest refineries when compared to the first quarter of 2012 and the fourth quarter of 2011. For the last half of 2012, we expect the economics to weaken for the Borger Refinery, as the price of Cushing crude oil rises relative to product prices and to strengthen for the Wood River Refinery which purchases primarily northern tier crude oils, which are expected to face increased discounts to product prices.

For the remainder of 2012 our continuing strategic initiatives and key priorities include:
- Growth of production at Christina Lake with expected first production at phase D in the third quarter of 2012 and ramping up through 2012;
- Conventional crude oil production increasing in 2012 primarily as a result of the development of our tight oil opportunities at Lower Shaunavon and Bakken while pursuing additional growth opportunities;
- Improved production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Progressing the Telephone Lake project; including investment in the dewatering pilot project;
- Obtaining partner approval for our Narrows Lake project, perform additional engineering and start construction;
- Committing to transportation initiatives and advance new and expanded market development initiatives for our crude oil in step with a marketing strategy to deliver on our production growth;
- Progressing implementation of our environmental strategy through business unit specific action plans; and
- Demonstrating stable and reliable CORE operations at the Wood River Refinery.

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

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of 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;
- Continue 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;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund 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;
- Lower our commodity price risk profile through refining integration and natural gas as well as a consistent risk management hedging strategy; and
- Maintain a sustainable dividend with a priority expected to be placed on growing the dividend as part of delivering a solid total shareholder return.

Our business plan outlines our targets of reaching 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. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, 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.

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. 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.

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
NGLs	Natural gas liquids
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.