Management's Discussion and Analysis
For the Three Months Ended March 31, 2012

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated April 24, 2012, should be read with our unaudited interim Consolidated Financial Statements and accompanying notes for the period ended March 31, 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 March 31, 2012, we had a market capitalization of approximately $27 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 quarter of 2012 was in excess of 156,000 barrels per day and our average natural gas production was in excess of 630 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 June 2010, we submitted a joint application and Environmental Impact Assessment ("EIA") at 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 anticipate receiving regulatory approval in the middle of 2012 with first production expected by the end of 2016.

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 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 ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, 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.

- **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 ConocoPhillips. 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 FIRST QUARTER OF 2012

The first quarter of 2012 continued the momentum from 2011. With the accelerated ramp up of production at phase C, utilizing new start-up technologies, Christina Lake achieved its nameplate gross production capacity of 58,000 barrels per day, ahead of schedule. Our refining business showed increased refined product output and improvements in 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. Our integrated strategy continues to prove valuable as widening price differentials for Canadian crude oil are captured in our lower feedstock costs for our U.S. inland refineries.

We successfully completed our stratigraphic test well program, drilling 419 gross stratigraphic test wells on our Oil Sands properties. The results from these stratigraphic test wells will be used to support the next phases of expansion at Foster Creek and Christina Lake, gather data on the quality of our emerging projects and support regulatory applications. We also successfully completed the winter work needed to commence operation of the Telephone Lake dewatering pilot.

Demonstrating our commitment to delivering a solid total shareholder return in the first quarter of 2012, we increased our dividend for the quarter by 10 percent to $0.22 per share. This increase was achieved without impeding our growth strategy as we also increased capital investment by over $185 million in the first three months of 2012 compared to the same period in 2011.

OPERATIONAL RESULTS

Our average total crude oil and NGLs production in the first quarter increased 14 percent to 156,850 barrels per day compared to 2011, mainly due to production increases from phase C at Christina Lake and from our Conventional crude oil operations in southern Alberta, and in Saskatchewan at our Lower Shaunavon and Bakken tight oil plays.

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

- Christina Lake production averaging 24,733 barrels per day, an increase of 15,649 barrels per day with the ramp up of production from phase C;
- Foster Creek production meeting expectations for the quarter, as the plant is operating efficiently. As a result of power outages and related issues Foster Creek production decreased slightly compared to the first quarter of 2011;
- Pelican Lake production steadily increasing over the previous three quarters. Average production in the first quarter of 2012 was 20,730 barrels per day, a decrease of three percent from the first quarter of 2011, as production shut-ins to execute infill drilling activities and expected natural declines were only partially offset by polymer injection activities;
- Average crude oil production from our Lower Shaunavon and Bakken tight oil plays more than doubling to 6,888 barrels per day;
- Conventional crude oil production in Alberta increasing six percent, primarily due to successful drilling programs and fewer weather and access issues which more than offset expected natural declines and minor operational issues;
- Natural gas production decreasing two percent primarily due to the divestiture of a non-core property early in the first quarter of 2012 and expected natural declines;
- Drilling a second well pair as part of the Grand Rapids pilot project; and
- Refined product output of 465 thousand barrels per day, an increase of 82 thousand barrels per day as a result of increased throughput attributable to the CORE project coker start-up at the Wood River Refinery and improved operating performance at the Borger Refinery.

FINANCIAL RESULTS

Our first quarter financial results benefited from higher average crude oil sales prices, increased crude oil volumes, increased refinery throughput and strong refining margins. The higher average crude oil prices improved operating cash flow from our crude oil and NGLs operations, although prices had a negative impact on 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 first quarter of 2012 compared to 2011 include:

- Revenues increasing $1,064 million, or 30 percent, primarily due to:
    - Refining and Marketing revenues increasing $710 million due to improved refined product prices and refining throughput;
    - Crude oil and NGLs average sales prices (excluding financial hedging) increasing 14 percent;
    - Crude oil and NGLs sales volumes increasing 16 percent;
    - Higher condensate prices and volumes used for blending; and
    - Natural gas revenues decreasing $80 million due to decreased production and average sales prices.
- Operating cash flow of $267 million from Refining and Marketing, an increase of $87 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. Higher refining margins due to favourable refined product pricing and discounted crude oil feedstock costs also contributed to the increase;
- Cash flow of $904 million, an increase of 30 percent, primarily due to improved crude oil and NGLs average sales volumes and prices as well as increased operating cash flow from Refining and Marketing partially offset by decreased natural gas sale prices and increased operating costs from our crude oil and NGLs operations consistent with the increases in our production;
- Operating earnings increasing 63 percent or $131 million, primarily due to higher operating cash flow and decreased general and administrative expense, partially offset by increased depreciation, depletion and amortization ("DD&A") and income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Increased capital investment of $187 million focused on the expansion at our producing Oil Sands operations and the development of tight oil opportunities in southern Alberta and Saskatchewan;
- Operating cash flow in excess of the related capital investment from our Conventional natural gas operations decreased $49 million primarily due to lower natural gas prices and production. The $113 million generated in the quarter partially funded 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.

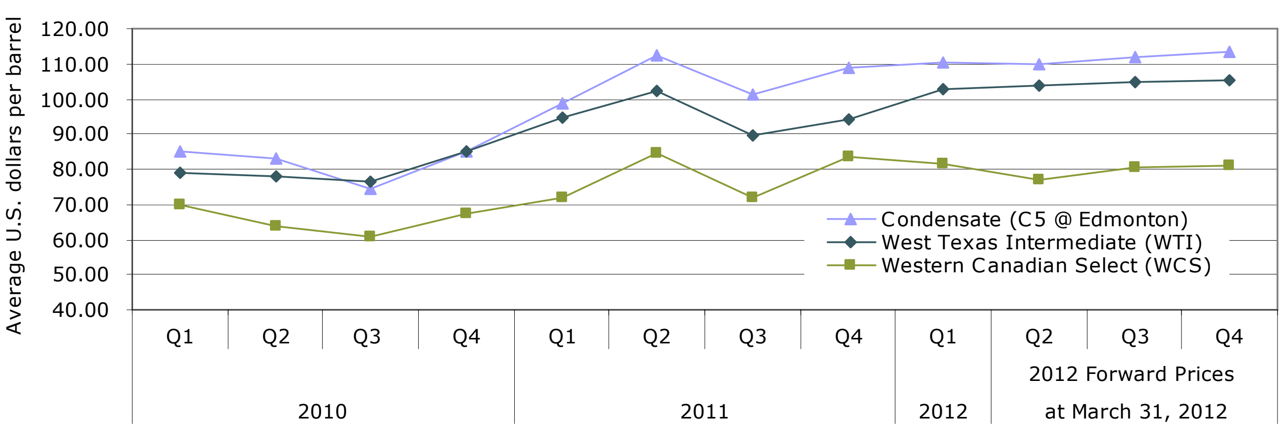
Selected Benchmark Prices and Exchange Rates

	2012	2011				2010			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
West Texas Intermediate (WTI)									
Average	**103.03**	94.06	89.54	102.34	94.60	85.24	76.21	78.05	78.88
End of period	**103.02**	98.83	79.20	95.42	106.72	91.38	79.97	75.63	83.45
Western Canadian Select (WCS)									
Average	**81.61**	83.58	71.92	84.70	71.74	67.12	60.56	63.96	69.84
End of period	**79.52**	84.37	69.38	75.32	91.37	72.87	64.97	61.38	70.25
Average Differential WTI-WCS	**21.42**	10.48	17.62	17.64	22.86	18.12	15.65	14.09	9.04
Average Condensate (C5 @ Edmonton)	**110.16**	108.74	101.48	112.33	98.90	85.24	74.53	82.87	84.98
Average Differential WTI-Condensate (premium)/discount	**(7.13)**	(14.68)	(11.94)	(9.99)	(4.30)	-	1.68	(4.82)	(6.10)
Refining Margin 3-2-1 Average Crack Spreads *(US$/bbl)*									
Chicago	**19.00**	19.23	33.35	29.00	16.62	9.25	10.34	11.60	6.11
Midwest Combined (Group 3)	**21.50**	20.75	34.04	27.19	19.04	9.12	10.60	11.38	6.82
Natural Gas Average Prices									
AECO *($/GJ)*	**2.39**	3.29	3.53	3.54	3.58	3.39	3.52	3.66	5.08
NYMEX *(US$/MMBtu)*	**2.74**	3.55	4.19	4.31	4.11	3.80	4.38	4.09	5.30
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.21**	0.17	0.34	0.42	0.29	0.28	0.78	0.32	0.19
U.S./Canadian Dollar Exchange Rate									
Average	**0.999**	0.978	1.020	1.033	1.015	0.987	0.962	0.973	0.961

Crude Oil Benchmarks

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. Over the first three months of 2012, WTI increased in reaction to growing supply outages in Sudan, Yemen and Syria as well as potential disruptions due to planned economic sanctions against Iran, which could limit crude oil shipments in the second half of this year. Partially mitigating these increases was continued uncertainty around the economic conditions of the European Union and the return of Libyan production.

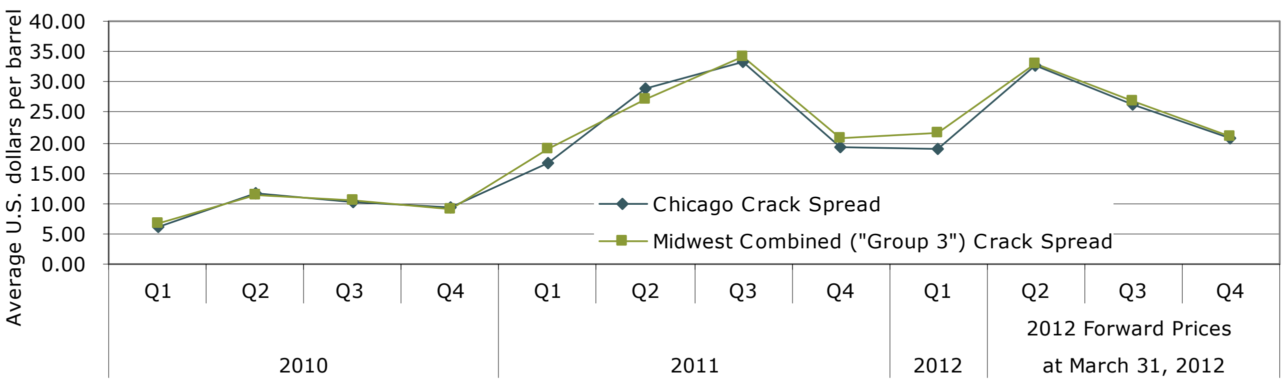
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the first quarter of 2012, the average WTI-WCS differential widened substantially compared to the fourth quarter of 2011 as growing crude oil supply from Canada and the northern United States begins to exhaust available pipeline capacity out of the region. New pipeline capacity is expected over the next year from Cushing, Oklahoma to the U.S. Gulf Coast, providing some improvements for Cushing-area crude oils such as WTI. This will likely have a widening effect on the WTI-WCS differential as it will have little impact on congestion out of Canada and the northern United States.



Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. Our blending ratios range from 10 percent to 35 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. In the first quarter of 2012, WTI discounts to offshore light crude oils (including Brent) increased and condensate premiums to WTI grew compared to the same period in 2011. The condensate premiums increased as the marginal barrel of condensate in Alberta is sourced from markets tied to global, rather than inland U.S., prices and as such do not include an inland U.S. discount embedded in the WTI benchmark price. The WTI discount to offshore light crude oils increased as inland supply continued to grow necessitating further discounts to encourage crude oil storage until sufficient pipeline access from Cushing, Oklahoma to the U.S. Gulf Coast is built. The reversal of the Seaway Pipeline, scheduled for the middle of 2012, should allow the WTI discount to narrow with full relief expected as additional capacity is added.

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 first quarter of 2012 improved compared to 2011 and remained consistent with the fourth quarter of 2011, benefiting from increased refined product pricing and inland crude oil discounts. However, inland refined product prices failed to keep pace with even stronger U.S. Gulf Coast refined product prices as the strong margins on inland refineries using discounted crude oil feedstock caused increased refinery runs and added refined product volumes in those markets.



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 first three months of 2012 remained low as the supply of natural gas from liquids-rich natural gas basins continued to increase and demand remained low due to the effects of a much warmer than average winter heating season. We do not expect prices to improve throughout the remainder of 2012 as demand growth is not expected to respond quickly enough to absorb the current storage surplus.

During the first three months of 2012, the Canadian dollar weakened slightly relative to the U.S. dollar compared to the first quarter of 2011. 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)	2012	2011				2010			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	**4,564**	4,329	3,858	4,009	3,500	3,363	2,962	3,094	3,222
Operating Cash Flow (1)	**1,085**	1,019	945	1,064	834	815	661	665	840
Cash Flow (1)	**904**	851	793	939	693	645	509	537	721
- per share – diluted	**1.19**	1.12	1.05	1.24	0.91	0.85	0.68	0.71	0.96
Operating Earnings (1)	**340**	332	303	395	209	147	156	143	353
- per share – diluted	**0.45**	0.44	0.40	0.52	0.28	0.19	0.21	0.19	0.47
Net Earnings	**426**	266	510	655	47	78	295	183	525
- per share – basic	**0.56**	0.35	0.68	0.87	0.06	0.10	0.39	0.24	0.70
- per share – diluted	**0.56**	0.35	0.67	0.86	0.06	0.10	0.39	0.24	0.70
Capital Investment (2)	**900**	903	631	476	713	701	479	444	491
Cash Dividends	**166**	151	150	151	151	151	150	150	150
- per share	**0.22**	0.20	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 PP&E and E&E assets and excludes acquisitions and divestitures.

REVENUES VARIANCE

(millions of dollars)	
Revenues for the Three Months Ended March 31, 2011	$ 3,500
Increase (decrease) due to:	
Oil Sands	318
Conventional	10
Refining and Marketing	710
Corporate and Eliminations	26
Revenues for the Three Months Ended March 31, 2012	$ 4,564

Oil Sands revenues for the first quarter of 2012 increased primarily due to increased crude oil sales, higher average crude oil sales prices as well as higher condensate volumes and prices.

Conventional revenues increased slightly for the three months ended March 31, 2012, as higher crude oil production and sales prices were almost completely offset by decreased natural gas sales prices and lower production volumes.

Refining and Marketing revenues in the first quarter increased primarily due to higher refined product volumes, an increase in refined product prices, as well as higher revenues related to operational third party sales undertaken by the marketing group also contributed to the overall revenue increase.

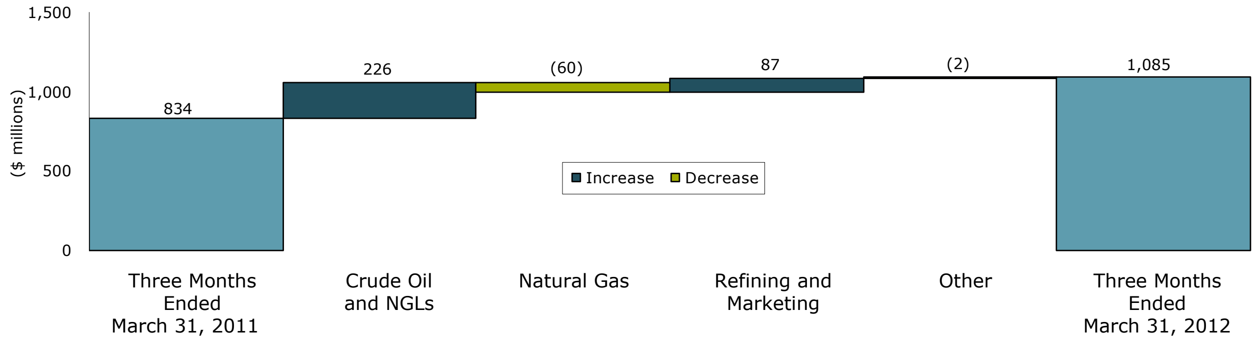
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

(millions of dollars)	Three Months Ended March 31, 2012	2011
Oil Sands		
Crude Oil and NGLs	**$ 417**	$ 250
Natural Gas	**4**	7
Other	**-**	2
Conventional		
Crude Oil and NGLs	**267**	208
Natural Gas	**128**	185
Other	**2**	2
Refining and Marketing	**267**	180
Operating Cash Flow	**$ 1,085**	$ 834

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.

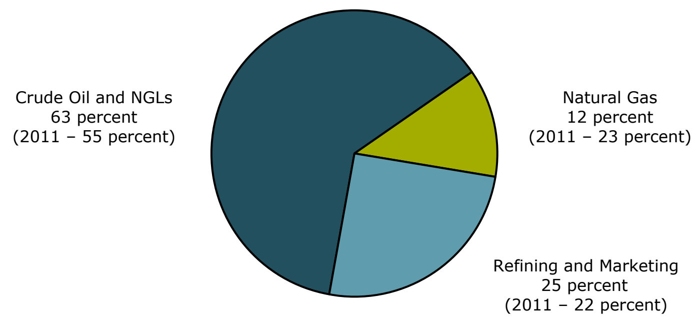
Operating Cash Flow Variance for the Three Months Ended March 31, 2012 compared to March 31, 2011



Overall, operating cash flow in the first quarter of 2012 increased $251 million primarily due to an increase in operating cash flow from crude oil and NGLs. This increase resulted from higher average crude oil sales prices and increased production volumes partially offset by increased operating costs. Refining and Marketing operating cash flow increased $87 million mainly due to higher throughput volume and continuing favourable refining margins. The $60 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 early in the first quarter of 2012 and expected natural declines.

Operating Cash Flow of $1,085 million for the Three Months Ended March 31, 2012

Crude oil and NGLs generated $684 million or 63 percent of our operating cash flow in the first quarter of 2012, an eight percent increase from the first quarter of 2011. The operating cash flow generated from Refining and Marketing increased to 25 percent. The percentage increases in crude oil and NGLs and Refining and Marketing were also impacted by a $60 million decrease in operating cash flow from our natural gas activities.



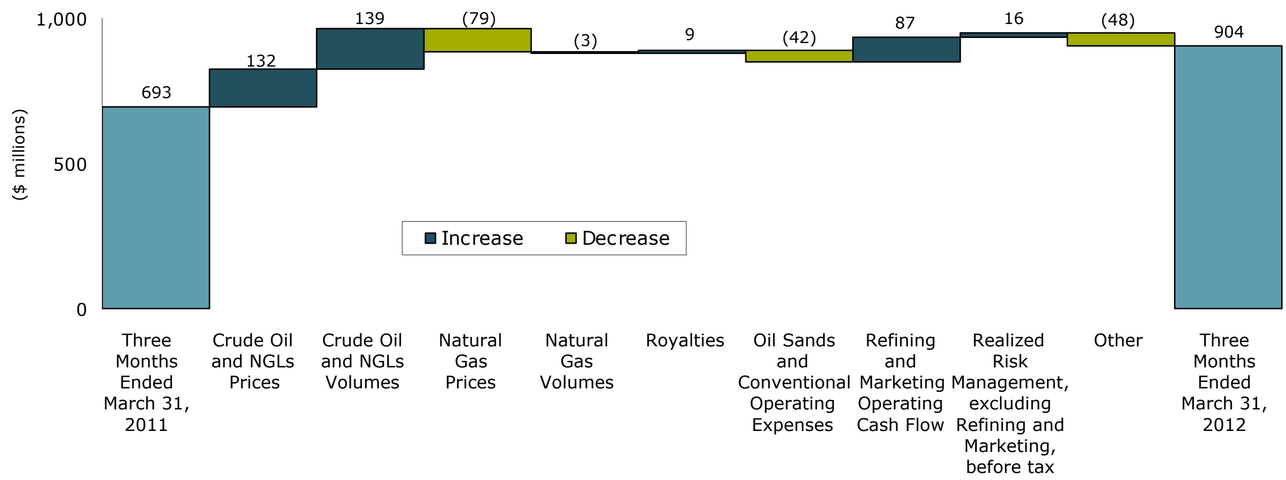
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

(millions of dollars)	Three Months Ended March 31, 2012	2011
Cash From Operating Activities	**$ 665**	$ 631
(Add back) deduct:		
Net change in other assets and liabilities	**(32)**	(29)
Net change in non-cash working capital	**(207)**	(33)
Cash Flow	**$ 904**	$ 693

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 March 31, 2012 compared to March 31, 2011



In the first quarter of 2012 our cash flow increased $211 million primarily due to:

- A 16 percent increase in our crude oil and NGLs sales volumes as a result of increased production primarily from the ramp up of production from phase C at Christina Lake and Conventional crude oil operations;
- A 14 percent increase in the average sales price of crude oil and NGLs to $74.28 per barrel;
- An increase in operating cash flow from Refining and Marketing of $87 million, mainly due to higher throughput, as heavy crude oil processing capability increased subsequent to coker start-up of the CORE project at the Wood River Refinery in the fourth quarter 2011 and continuing favourable refining margins;
- Realized risk management gains before tax, excluding Refining and Marketing, of $35 million compared to gains of $19 million in the first quarter of 2011; and
- A decrease in royalties of $9 million primarily as a result of increased capital investment at Foster Creek and Pelican Lake as well as receiving Alberta Department of Energy approval in the second quarter of 2011 to include Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation.

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

- A 35 percent decrease in the average natural gas sales price to $2.50 per Mcf;
- Increased operating expenses, primarily from crude oil and NGLs production, relating to the significant increase in production from Christina Lake phase C which came on production in the third quarter of 2011. Operating costs were also higher at Foster Creek and Pelican Lake due to additional personnel to support future expansions, increased workovers, repairs and maintenance activity and increased production from the Bakken and Lower Shaunavon areas, where production has been predominantly from single well batteries, resulting in increased trucking, fluid hauling and equipment rentals;
- A $33 million increase in current income tax expense due to improved operating cash flows in Canada;
- Higher general and administrative expense, excluding long-term incentives, due to increased office support and information technology costs; and
- Natural gas production declining two 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 March 31,	
(millions of dollars)	**2012**	2011
Net Earnings	**$ 426**	$ 47
(Add back) deduct:		
Unrealized risk management gains (losses), after-tax [1]	**48**	(201)
Non-operating foreign exchange gains (losses), after-tax [2]	**38**	39
Operating Earnings	**$ 340**	$ 209

[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 increase in operating earnings in the first quarter of 2012 is consistent with higher operating cash flow and decreased general and administrative expense due to lower long-term incentive costs, partially offset by higher DD&A and 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)		
Net Earnings for the Three Months Ended March 31, 2011	$	47
Increase (decrease) due to:		
Operating Cash Flow		251
Corporate and Eliminations		
Unrealized risk management gains (losses), after-tax		249
Unrealized foreign exchange gains (losses)		(5)
Expenses [1]		23
Depreciation, depletion and amortization		(94)
Income taxes, excluding income taxes on unrealized risk management gains (losses)		(45)
Net Earnings for the Three Months Ended March 31, 2012	**$**	**426**

[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 first quarter of 2012, our net earnings increased $379 million compared to the first quarter of 2011. The factors discussed above that increased our operating cash flow in the first quarter of 2012 also increased our net earnings. Other significant factors that impacted our net earnings in the first quarter of 2012 include:

- Unrealized risk management gains, after-tax, of $48 million, compared to losses of $201 million in the first quarter of 2011;
- Unrealized foreign exchange gains of $31 million compared to gains of $36 million in the first quarter of 2011, consistent with the weakening of the Canadian dollar exchange rate at March 31, 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;
- A decrease of $20 million for general and administrative expenses primarily due to decreased long-term incentive expense partially offset by increases in office support and information technology costs;
- An increase of $94 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; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $152 million, compared to $107 million for the same period in 2011.

NET CAPITAL INVESTMENT

	Three Months Ended March 31,			
(millions of dollars)		**2012**		2011
Oil Sands	**$**	**636**	$	404
Conventional		**231**		176
Refining and Marketing		**(2)**		102
Corporate		**35**		31
Capital Investment		**900**		713
Acquisitions		**8**		19
Divestitures		**(66)**		(4)
Net Capital Investment [1]	**$**	**842**	$	728

[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 first quarter of 2012 compared to 2011 included higher spending on fabrication and facility construction for phase F, earthworks and site preparation for phase G and design engineering for phase H at Foster Creek. At Christina Lake, capital investment included site preparation and facility construction for expansion phases E and F. Pelican Lake capital investment included infill drilling for polymer flooding and facility expansion and maintenance. We also drilled 419 gross stratigraphic test wells in the first three months of 2012, down from 440 gross wells drilled during the first quarter 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 first quarter of 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 at our Alberta 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 first three months of 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 related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment in the first quarter of 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 using the smallest amount 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 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

Divestitures in the first quarter of 2012 were mainly for the sale 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 March 31,	
(millions of dollars)	**2012**	2011
Cash Flow	**$ 904**	$ 693
Capital Investment (Committed and Growth)	**900**	713
Free Cash Flow [(1)]	**4**	(20)
Dividends paid	**166**	151
	$ (162)	$ (171)

[(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 March 31,					
	2012			2011		
(millions of dollars)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	**$ (26)**	**$ 30**	**$ 4**	$ (34)	$ (260)	$ (294)
Natural Gas	**60**	**36**	**96**	52	(33)	19
Refining	**(5)**	**3**	**(2)**	(5)	3	(2)
Power	**-**	**(5)**	**(5)**	1	22	23
Gains (Losses) on Risk Management	**29**	**64**	**93**	14	(268)	(254)
Income Tax Expense (Recovery)	**6**	**16**	**22**	3	(67)	(64)
Gains (Losses) on Risk Management, after-tax	**$ 23**	**$ 48**	**$ 71**	$ 11	$ (201)	$ (190)

In the first quarter of 2012, our risk management strategy resulted in realized losses on our crude oil financial instruments and realized gains on our 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 increased WTI benchmark crude oil prices which ended the first quarter of 2012 at a higher average price than the same period in 2011. We also recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices at the end of the first quarter in 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

	2012	2011				2010			
(barrels per day)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil Sands									
Foster Creek	**57,214**	55,045	56,322	50,373	57,744	52,183	50,269	51,010	51,126
Christina Lake	**24,733**	19,531	10,067	7,880	9,084	8,606	7,838	7,716	7,420
Pelican Lake	**20,730**	20,558	20,363	19,427	21,360	21,738	23,259	23,319	23,565
Conventional									
Heavy Oil	**16,624**	15,512	15,305	15,378	16,447	16,553	16,921	16,205	16,962
Light & Medium Oil	**36,411**	32,530	30,399	27,617	31,539	29,323	28,608	29,150	30,320
NGLs [1]	**1,138**	1,097	1,040	1,087	1,181	1,190	1,172	1,166	1,156
	156,850	144,273	133,496	121,762	137,355	129,593	128,067	128,566	130,549

[1] NGLs include condensate volumes.

For the first quarter of 2012, our total crude oil and NGLs production increased 14 percent compared to the same period in 2011, primarily due to higher production at Christina Lake with the ramp up of phase C as well as increased production from our Conventional crude oil operations where the impact of our tight oil development increased our light and medium crude oil production. We effectively managed the natural declines to our Conventional heavy oil production where production increased slightly compared to the same period in 2011. Further information on the changes in our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

	2012	2011				2010			
(MMcf per day)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Conventional	**595**	622	617	617	620	649	694	705	730
Oil Sands	**41**	38	39	37	32	39	44	46	45
	636	660	656	654	652	688	738	751	775

The 16 MMcf per day decrease in our natural gas production in the first 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 was consistent with the same period in 2011, as expected natural declines were offset by a decrease in the internal use of our natural gas production at our Foster Creek operation due to deliverability issues. Further information on the changes in our natural gas production can be found in the Reportable Segments section of this MD&A.

OPERATING NETBACKS

	Three Months Ended March 31,			
	2012		2011	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
Price [1]	**$ 74.28**	**$ 2.50**	$ 65.37	$ 3.82
Royalties	**8.05**	**0.06**	9.98	0.08
Transportation and blending [1]	**2.81**	**0.13**	2.60	0.17
Operating expenses	**14.71**	**1.08**	13.43	1.19
Production and mineral taxes	**0.59**	**0.02**	0.36	0.06
Netback excluding Realized Risk Management	**48.12**	**1.21**	39.00	2.32
Realized Risk Management Gains (Losses)	**(1.67)**	**1.03**	(2.67)	0.89
Netback including Realized Risk Management	**$ 46.45**	**$ 2.24**	$ 36.33	$ 3.21

(1) The crude oil and NGLs price and transportation and blending costs exclude $30.14 per barrel (2011 - $24.96 per barrel) of condensate purchases which is blended with heavy crude oil.

In the first quarter of 2012, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $9.12 per barrel primarily due to increased sales prices consistent with higher benchmark prices and access to higher priced markets. Also increasing our netback was decreased Oil Sands royalties due to increased capital investment. These increases were partially offset by higher operating expenses primarily due to higher staffing levels, increased workovers and repairs and maintenance. Transportation costs increased primarily due to higher sales to the U.S. and increased use of rail capacity partially offset by the utilization of our firm service capacity to transport crude oil to the Canadian west coast on the Trans Mountain pipeline system.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $1.11 per Mcf in the first quarter of 2012 due to lower sales prices partially offset by decreased operating expenses primarily due to reduced electricity costs due to lower prices.

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 first quarter of 2012 include:

- Christina Lake production more than doubling, to an average of 24,733 barrels per day, with the ramp up of production from phase C using new start-up technologies;
- Christina Lake achieved gross nameplate production capacity of 58,000 barrels per day;
- Foster Creek average production meeting expectations for the quarter as the plant is operating efficiently. As a result of power outages and related issues Foster Creek production decreased slightly compared to the first quarter of 2011;
- Successfully completing a large winter stratigraphic test well program with 419 gross wells drilled to further progress our Oil Sands projects and successfully completing the winter work needed to commence operation of the Telephone Lake dewatering pilot;
- While Pelican Lake production has steadily increased over the previous three quarters, average production in the first quarter of 2012 was 20,730 barrels per day, a decrease of three percent from the first quarter of 2011, as production shut-ins to execute infill drilling activities and expected natural declines were only partially offset by polymer injection activities; and
- Drilling a second well pair as part of the Grand Rapids pilot project.

OIL SANDS - CRUDE OIL

Financial Results

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Gross Sales	**$ 1,087**	$ 784
Less: Royalties	**65**	82
Revenues	**1,022**	702
Expenses		
Transportation and blending	**449**	321
Operating	**138**	107
(Gains) losses on risk management	**18**	24
Operating Cash Flow	**417**	250
Capital Investment	**631**	390
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	**$ (214)**	$ (140)

Revenues Variances

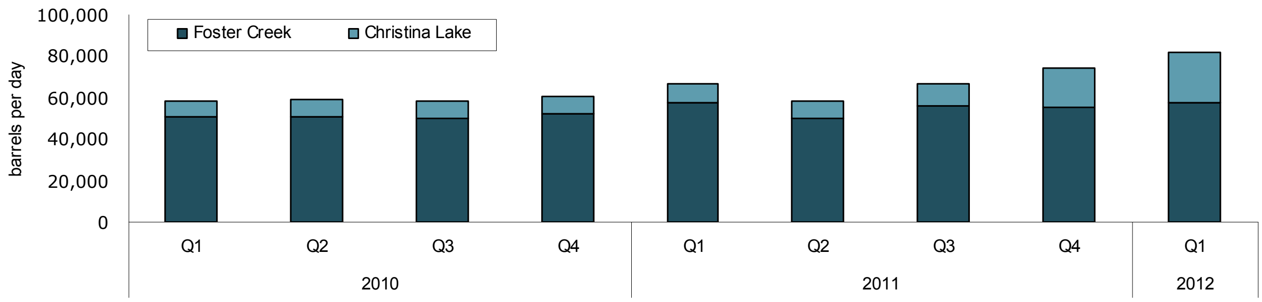
(millions of dollars)	Three Months Ended March 31, 2011	Price	Volume	Royalties	Condensate[1]	**Three Months Ended March 31, 2012**
	$ 702	78	100	17	125	**$ 1,022**

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

Production Volumes

Crude oil (barrels per day)	Three Months Ended March 31, 2012	2012 vs 2011	2011
Foster Creek	**57,214**	**-1%**	57,744
Christina Lake	**24,733**	**172%**	9,084
Subtotal	**81,947**	**23%**	66,828
Pelican Lake	**20,730**	**-3%**	21,360
	102,677	**16%**	88,188

Foster Creek and Christina Lake Production Volumes by Quarter



In the first quarter of 2012, our average crude oil sales price increased 13 percent to $68.36 per barrel compared to 2011, consistent with the increase in the WCS benchmark price, partially offset by higher condensate costs. A portion of our Christina Lake production is being sold as a new bitumen blend stream, Christina Dilbit Blend ("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.

Foster Creek production met expectations for the quarter as the plant is operating efficiently however, production decreased slightly in the first quarter 2012 compared to 2011, primarily as a result of several power outages. Production at Foster Creek is expected to be lower in the second quarter of 2012 as a result of a scheduled plant turnaround which occurs in May. The substantial increase in production at Christina Lake was the result of the start-up of phase C in the third quarter of 2011 and four wells (which use our Wedge Well™ technology) which came on production in 2011. Pelican Lake production has steadily increased over the previous three quarters. Average production in the first quarter of 2012 decreased three percent from 2011, as production shut-ins to execute infill drilling activities and expected natural declines were only partially offset by polymer injection activities.

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 price, volume, allowed operating and capital costs for post-payout projects (Foster Creek and Pelican Lake). Royalties decreased $17 million in the first three months of 2012, primarily due to increased capital investment at Foster Creek and Pelican Lake and receiving Alberta Department of Energy approval in the second quarter of 2011 to include Foster Creek expansion phases F, G and H capital investment as part of our Foster Creek royalty calculation. Christina Lake royalties were higher as a result of higher production and higher Canadian dollar WTI prices. The effective royalty rates for the first quarter of 2012 were 13.9 percent at Foster Creek (2011 – 21.2 percent), 7.0 percent at Christina Lake (2011 – 4.8 percent) and 4.5 percent at Pelican Lake (2011 – 13.9 percent).

Transportation and blending costs increased $128 million in the first quarter of 2012. The condensate (blending) portion of the increase was $125 million, the result of higher volumes required due to increased production at Christina Lake and increases in the average cost of condensate. Transportation costs increased $3 million primarily as a result of higher Christina Lake production volumes and increased deliveries to the U.S., partially offset by lower transportation charges on the Trans Mountain pipeline system, with our long term commitment to firm service, which commenced in February 2012.

Our operating costs for the first quarter of 2012 were primarily for workovers, workforce costs, chemical usage, repairs and maintenance and Foster Creek and Christina Lake fuel costs. In total, operating costs increased $31 million in the first quarter of 2012 primarily due to an $18 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 20 percent to $15.33 per barrel due to the increase in production. Operating costs increased at both Foster Creek and

Pelican Lake due to increased workovers, higher staffing levels to support future expansions and increased repairs and maintenance, partially offset by decreased chemical and fuel costs.

Risk management activities resulted in realized losses of $18 million (2011 – losses of $24 million), consistent with average benchmark prices in the first quarter 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 properties. Our natural gas production increased to 41 MMcf per day in the first quarter of 2012 (2011 – 32 MMcf per day), primarily as a result of a reduction in the use of our natural gas production at our Foster Creek operation due to deliverability issues, partially offset by expected natural declines. Lower natural gas prices more than offset increases due to higher production volumes, resulting in operating cash flow declining to $4 million for the first quarter of 2012 (2011 - $7 million).

OIL SANDS - CAPITAL INVESTMENT

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Foster Creek	**$ 159**	$ 103
Christina Lake	**127**	108
Subtotal	**286**	211
Pelican Lake	**139**	84
Narrows Lake	**9**	10
Telephone Lake	**91**	27
Grand Rapids	**34**	18
Other [1]	**77**	54
Capital Investment [2]	**$ 636**	$ 404

[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 the first quarter of 2012 was 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 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 the first quarter of 2012 compared to 2011 primarily as a result of higher spending on fabrication and facility construction for phase F, earthworks and site preparation for phase G, design engineering for phase H and drilling 124 gross stratigraphic test wells (2011 – 110 wells).

Christina Lake capital investment was higher in the first quarter of 2012 compared to 2011 due primarily to the phase E and F expansions, including site preparation and facility construction as well as increased capital related to maintaining and increasing our production levels. This was partially offset by the completion of phase C in the second quarter of 2011 and drilling fewer gross stratigraphic test wells (2012 – 28 wells; 2011 – 59 wells). Phase D construction continued in the first quarter of 2012. We expect to increase gross production capacity to approximately 138,000 barrels per day with the completion of phases D and E. First production at phase D is expected in the fourth quarter of 2012 and first production at phase E is expected in the fourth quarter of 2013.

Pelican Lake capital investment for the first three months of 2012 was primarily related to infill drilling to progress the polymer flood, facilities expansions and maintenance capital. Facilities spending focused on expanding fluid capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

Remaining capital investment in the first quarter of 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])	Three Months Ended March 31, 2012	2011
Foster Creek	**10**	7
Christina Lake	**9**	8
Subtotal	**19**	15
Pelican Lake	**13**	-
Grand Rapids	**1**	-
Other	**-**	3
	33	18

(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)	Three Months Ended March 31, 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 30 observation wells (2011 – nil) 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 first quarter of 2012 include:

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $113 million;
- Average crude oil production from our Lower Shaunavon and Bakken tight oil plays more than doubling to 6,888 barrels per day with capital spending focusing on drilling, completions and facilities;
- Conventional crude oil production in Alberta increasing six percent, primarily due to successful drilling programs and fewer weather and access issues, which more than offset expected natural declines and minor operational issues;
- Natural gas production decreasing four percent to 595 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 41 percent. We have also reduced natural gas capital investment due to low prices.

CONVENTIONAL - CRUDE OIL and NGLs

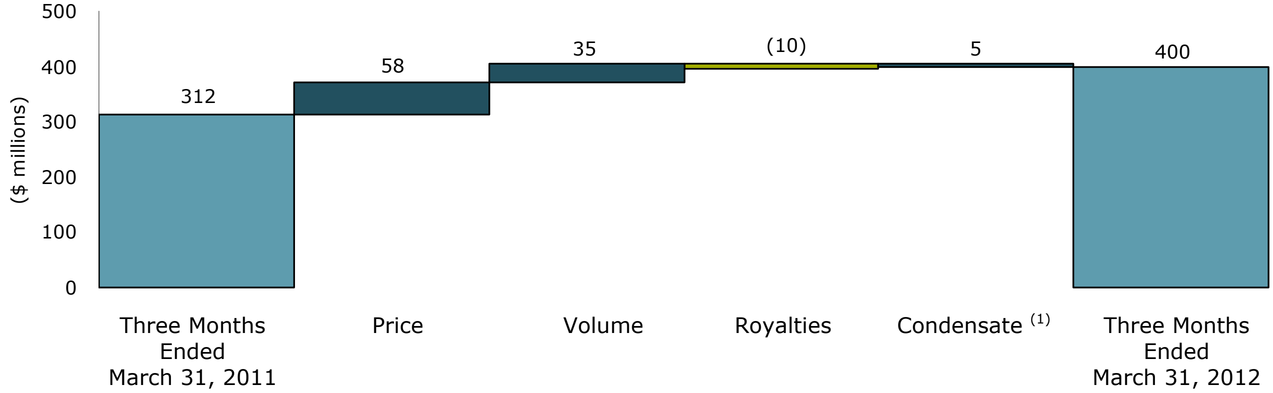
Financial Results

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Gross Sales	**$ 454**	$ 356
Less: Royalties	**54**	44
Revenues	**400**	312
Expenses		
Transportation and blending	**38**	27
Operating	**79**	63
Production and mineral taxes	**9**	5
(Gains) losses on risk management	**7**	9
Operating Cash Flow	**267**	208
Capital Investment	**216**	153
Operating Cash Flow in Excess of Related Capital Investment	**$ 51**	$ 55

Production Volumes

	Three Months Ended March 31,		
(barrels per day)	**2012**	**2012 vs 2011**	2011
Heavy Oil			
Alberta	**16,624**	**1%**	16,447
Light and Medium Oil			
Alberta	**12,898**	**14%**	11,326
Saskatchewan	**23,513**	**16%**	20,213
NGLs	**1,138**	**-4%**	1,181
	54,173	**10%**	49,167

Revenues Variance for the Three Months Ended March 31, 2012 compared to March 31, 2011



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

Our average crude oil and NGLs sales price for the first three months of 2012 increased 15 percent to $85.86 per barrel compared to the same period in 2011, consistent with the increase in crude oil benchmark prices.

Our crude oil and NGLs production increased 10 percent in the first quarter of 2012 as a result of successful capital programs and improved weather conditions in 2012 which more than offset expected natural declines. Our heavy oil production in Alberta also had fewer access issues in 2012.

Royalties increased by $10 million primarily as a result of increased crude oil prices and volumes. The effective crude oil royalty rate for the first three months of 2012 and 2011 was 13.4 percent.

Transportation and blending costs increased $11 million in the first quarter of 2012 compared to 2011. The condensate portion of the increase was $5 million and was due to increases in the average cost of condensate and volumes required for blending due to increased heavy oil production. Transportation costs increased $6 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls and increased costs on accessing new markets, including through the use of 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 first quarter of 2012 primarily due to higher repairs and maintenance, workover activity, increased workforce costs, higher equipment rentals and increased trucking and waste handling costs. These increases in operating costs include the effects of our Lower Shaunavon and Bakken production more than doubling in the first quarter of 2012.

Risk Management activities in the first three months of 2012 resulted in realized losses of $7 million (2011 - losses of $9 million) consistent with the average benchmark prices in the first quarter of 2012 exceeding our 2012 contract prices.

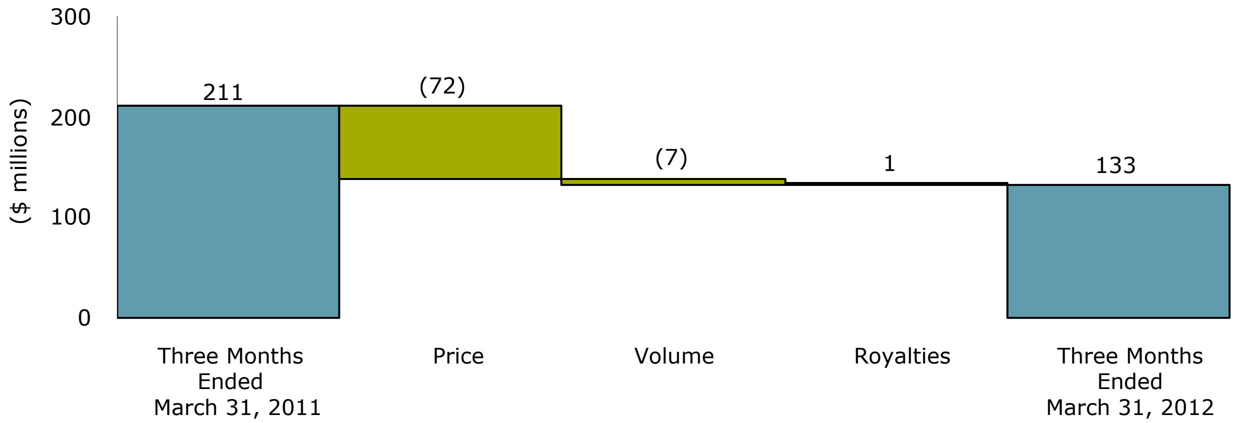
Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by $4 million in the first quarter of 2012 as the $63 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was almost offset by the $59 million increase in operating cash flow attributed to higher crude oil and NGLs prices and the 10 percent increase in crude oil production.

CONVENTIONAL - NATURAL GAS

Financial Results

(millions of dollars)	Three Months Ended March 31, 2012	2011
Gross Sales	**$ 135**	$ 214
Less: Royalties	**2**	3
Revenues	**133**	211
Expenses		
Transportation and blending	**6**	10
Operating	**54**	61
Production and mineral taxes	**1**	3
(Gains) losses on risk management	**(56)**	(48)
Operating Cash Flow	**128**	185
Capital Investment	**15**	23
Operating Cash Flow in Excess of Related Capital Investment	**$ 113**	$ 162

Revenues Variance for the Three Months Ended March 31, 2012 compared to March 31, 2011



Our natural gas revenues and operating cash flow were lower in the first quarter of 2012, primarily due to decreased average sales prices consistent with the change in the benchmark AECO price and lower production. Our natural gas production in the first quarter of 2012 decreased four percent to 595 MMcf per day, primarily due to the divestiture of a non-core property early in the first quarter of 2012, reducing production by 15 MMcf per day. Further decreasing production was expected natural declines partially offset by fewer weather issues in 2012. Excluding the impact of the non-core divestiture, our natural gas production would have decreased two percent from the same period in 2011.

Royalties decreased $1 million in the first quarter of 2012 due to lower prices and volumes. The average royalty rate in the first quarter of 2012 was 1.7 percent (2011 – 1.4 percent).

Transportation costs decreased $4 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 $7 million in the first 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, chemical and property taxes and lease rental costs. We also had reduced electricity costs due to lower prices in 2012.

Risk management activities in the first three months of 2012 resulted in realized gains of $56 million (2011 – gains of $48 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 $49 million primarily due to lower average sales prices and production volumes partially offset by an $8 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

	Three Months Ended March 31,	
($ millions)	**2012**	2011
Crude Oil	**$ 216**	$ 153
Natural Gas	**15**	23
Capital Investment [1]	**$ 231**	$ 176

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

Capital investment in our Conventional segment was focused on crude oil development opportunities. Increased crude oil capital investment in Saskatchewan was focused on facility work in the Lower Shaunavon and Bakken areas where we expect to complete the construction of two batteries and eight field satellites in the second 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.

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 Alberta coal bed methane development.

Conventional Wells Drilled

	Three Months Ended March 31,	
(net wells)	**2012**	2011
Crude oil	**102**	103
Natural gas	**-**	15
Recompletions	**452**	456
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 ConocoPhillips. 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 first quarter of 2012 include:

- A significant increase in throughput and refined product output resulting from coker start-up of the CORE project at the Wood River Refinery as well as improved operating performance at the Borger Refinery;
- First quarter results also reflect improved refining margins, consistent with higher benchmark crack spreads, and the ability to process a greater proportion of heavy crudes as a result of CORE;
- Operating cash flow increasing $87 million to $267 million primarily due to increased refined product volumes and improved refining margins; and
- Our refineries processing 445 thousand barrels per day of crude oil resulting in 465 thousand barrels per day of refined product output.

Financial Results

(millions of barrels)	Three Months Ended March 31, 2012	2011
Revenues	**$ 2,992**	$ 2,282
Purchased product	**2,589**	1,969
Gross margin	**403**	313
Expenses		
Operating expenses	**130**	128
(Gain) loss on risk management	**6**	5
Operating Cash Flow	**267**	180
Capital Investment	**(2)**	102
Operating Cash Flow in Excess of Capital Investment	**$ 269**	$ 78

The gross margin for Refining and Marketing increased $90 million in the first quarter of 2012 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 in the fourth quarter of 2011. As was the case throughout 2011, refining margins in the first quarter of 2012 continue 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, were consistent in the first quarter of 2012. While there is an increase in utility usage at the Wood River Refinery subsequent to CORE project start-up, utilities expense declined 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 costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $87 million to $267 million in the first quarter of 2012 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 $104 million in the first quarter of 2012 with the completion of CORE project coker construction at the Wood River Refinery in the fourth quarter of 2011, as well as Illinois tax credits related to capital expenditures at the Wood River Refinery in prior periods.

REFINERY OPERATIONS [1]

	Three Months Ended March 31, 2012	2011
Crude oil capacity *(Mbbls/d)*	**452**	452
Crude oil runs *(Mbbls/d)*	**445**	362
Crude utilization *(percent)*	**98**	80
Refined products *(Mbbls/d)*	**465**	383

[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 first quarter of 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 crudes remains dependent on the quality of available crudes 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.

REFINING AND MARKETING - CAPITAL INVESTMENT

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Wood River Refinery	**$ (8)**	$ 96
Borger Refinery	**6**	6
Marketing	**-**	-
Capital Investment	**$ (2)**	$ 102

With the CORE project coker construction now complete, our refining capital investment in the first quarter of 2012 was primarily related to refinery reliability and maintenance projects. In addition, 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 in the first quarter of 2012.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Revenues	**$ -**	$ (26)
Expenses ((add)/deduct)		
Purchased product	**-**	(26)
Operating	**(1)**	(1)
(Gains) losses on risk management	**(64)**	268
	$ 65	$ (267)

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:

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
General and administrative	**$ 93**	$ 113
Finance costs	**113**	117
Interest income	**(29)**	(32)
Foreign exchange (gain) loss, net	**(16)**	(23)
Other (income) loss, net	**(5)**	(1)
	$ 156	$ 174

General and administrative expenses decreased $20 million in the first quarter of 2012, primarily due to lower long-term incentive expense partially offset by increased office support and information technology costs.

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 first quarter of 2012, our finance costs were $4 million lower than 2011, primarily as a result of decreased interest on the partnership contribution payable as principal payments are made quarterly. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for the first three months of 2012 was 5.4 percent (2011 – 5.6 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the first quarter of 2012 decreased by $3 million from the same period from 2011 mainly as a result of decreasing interest being earned on the partnership contribution receivable as the balance is being collected.

In the first quarter of 2012, we reported net foreign exchange gains of $16 million (2011 - gains of $23 million), which includes unrealized gains of $31 million (2011 – unrealized gains of $36 million) and realized losses of $15 million (2011 – realized losses of $13 million). The Canadian dollar exchange rate strengthened less in the first quarter of 2012 compared to the first quarter of 2011 which led to lower unrealized gains on our U.S. dollar denominated long-term debt and decreased unrealized losses on our U.S. dollar denominated partnership contribution receivable.

DEPRECIATION, DEPLETION and AMORTIZATION

	Three Months Ended March 31,	
(millions of dollars)	**2012**	2011
Oil Sands	**$ 115**	$ 86
Conventional	**236**	195
Refining and Marketing	**38**	16
Corporate and Eliminations	**11**	9
	$ 400	$ 306

Oil Sands DD&A for the first three months of 2012, increased $29 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 $41 million in the first quarter of 2012 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 $22 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.

INCOME TAX EXPENSE

	Three Months Ended March 31,	
(millions of dollars except percent amounts)	**2012**	2011
Current tax		
Canada	**$ 62**	$ 41
United States	**12**	-
Total current tax	**74**	41
Deferred tax	**94**	(1)
Income tax expense	**$ 168**	$ 40
Effective tax rate	**28%**	46%

When comparing the first quarter of 2012 to 2011, our current tax expense increased primarily due to improved operating cash flow from operations in Canada. We expect to have sufficient deductions to shelter our U.S. federal taxable income for 2012. The U.S. current tax in the first quarter of 2012 reflects state income tax.

When comparing the first quarter of 2012 to 2011, our deferred tax expense increased primarily due to increased operating cash flow from our Refining and Marketing segment which attracts income tax at the higher U.S. tax rates and higher unrealized risk management gains.

Our effective tax rate reflects income in Canada and the U.S. at their relevant statutory tax rates. The effective tax rate for 2011 reflects a loss in Canada, a lower tax rate jurisdiction, and income in the U.S., a higher tax rate jurisdiction.

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 March 31,	
(millions of dollars)	**2012**	2011
Net cash from (used in)		
Operating activities	**$ 665**	$ 631
Investing activities	**(832)**	(684)
Net cash provided (used) before Financing activities	**(167)**	(53)
Financing activities	**138**	130
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**(6)**	2
Increase (decrease) in cash and cash equivalents	**$ (35)**	$ 79

OPERATING ACTIVITIES

Cash from operating activities increased $34 million in the first quarter of 2012 compared to the same period in 2011 mainly because of a $211 million increase in cash flow, which is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in non-cash working capital and 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 $137 million at March 31, 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 first quarter of 2012 increased $148 million from the same period in 2011. The increase is primarily due to higher capital expenditures, which increased by $179 million, partially offset by increased proceeds from the divestiture of assets of $64 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 first quarter of 2012, we increased our dividend by 10 percent, paying a dividend of $0.22 per share (2011 – $0.20 per share). Total dividend payments in the first quarter of 2012 were $166 million (2011 - $151 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash from financing activities in the first three months of 2012 increased $8 million to $138 million compared to the same period in 2011. The increase was due to higher issuances of short-term borrowings partially offset by the increased dividends on common shares.

Our long-term debt was $3,465 million as at March 31, 2012 and no payments of principal are due until September 2014 (US$800 million). We had short-term borrowings of $270 million under our commercial paper program and we also had cash resources of $460 million some of which was held by joint operations.

AVAILABLE SOURCES OF LIQUIDITY

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 March 31, 2012, we had $270 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.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus. The Canadian debt shelf prospectus expires in July 2012 and the U.S. debt shelf prospectus in August 2012. It is our intention to renew both prospectuses prior to their expiration.

As at March 31, 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.

	March 31, 2012	December 31, 2011
Debt to Capitalization	**28%**	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 the end of the first quarter of 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 March 31, 2012, approximately 755.6 million common shares were outstanding and no preferred shares were outstanding.

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 March 31, 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 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 to transport crude oil; 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 corporate 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 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 July 2011 we released our first comprehensive corporate responsibility 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. Our 2011 CR report is expected to be released by July 2012.

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 the first quarter of 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 quarter 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 commodity prices including the effect of new market access for North American crude oil. Crude oil prices are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

For the remainder of 2012, the average price of Brent crude is expected to be at higher levels than 2011 due to continued production outages in Syria, Sudan and Yemen as well as further loss of crude oil supply due to sanctions on Iran. Brent prices remain sensitive to events in Europe and the general slowing of the global economy but there are signs that the worst may be behind us. In addition, with very strong levels of output, Saudi Arabia is in good position to defend prices in the event of any transitory weakness in markets.

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

In the first quarter of 2012, the WTI-WCS differential widened due to growth of inland crude oil supply, as well as lower demand as some refineries in the U.S. Midwest engaged in maintenance activities temporarily decreasing refining capacity. With supply growth expected to continue and only minimal increases in pipeline capacity and only limited incremental rail capacity, there should be a continued widening of Canadian differentials including WCS. This pattern will be aggravated by the commissioning of the Seaway Pipeline reversal as it will offer relief for Cushing crude, including WTI, but will provide minimal benefits for Canadian crude oil.

Increased refined product prices and decreased heavy oil feedstock costs in the first three months of 2012 resulted in improved economics for U.S. Midwest refineries. For the remainder of 2012 we expect the economics to improve for those inland refineries that use Canadian tier crudes but deteriorate for those refineries more reliant on Cushing-area crude.

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

- Growth of production at Christina Lake with ramp up of phase C production and expected first production at phase D in the fourth quarter of 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;
- Investment in the dewatering pilot project at Telephone Lake;
- Progressing the Telephone Lake project;
- Anticipating regulatory and 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 environmental strategy through business unit specific action plans; and
- Demonstrating stable and reliable CORE operations at the Wood River Refinery.

In April 2012, our partner ConocoPhillips announced that its Board of Directors had given final approval to the spin-off of its downstream business from its exploration and production business. The Exploration and Production entity will keep the ConocoPhillips name and the Downstream entity will be known as Phillips 66. We expect our partnership and related agreements with ConocoPhillips to be amended to accommodate the separation and holding of the upstream assets and refining assets in two separate companies and do not anticipate a significant impact to our business.

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 mainly 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; the ability of us and ConocoPhillips to maintain our relationship 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 Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or 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		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
NGLs	Natural gas liquids	GJ	Gigajoule
WTI	West Texas Intermediate	CBM	Coal Bed Methane
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend		
TM	Trademark of Cenovus Energy Inc.		

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.