

First Quarter 2012



Cenovus oil production growth continues with 14% increase Cash flow in the first quarter up 30% over last year at \$904 million or \$1.19 per share

- Oil sands production at Foster Creek and Christina Lake averaged almost 82,000 barrels per day (bbls/d) net to Cenovus in the first quarter, a 23% increase compared with 2011.
- Conventional oil and natural gas liquids (NGLs) production, including Pelican Lake, averaged about 75,000 bbls/d, 6% more than the same period a year earlier.
- Cash flow for the quarter was \$904 million, or \$1.19 per share diluted, an increase of 30% compared with the same period a year earlier.
- Operating cash flow from refining operations was \$266 million, an increase of 48% compared with the same period a year ago.
- Capital investment continues to focus on the company's oil assets and increased by \$187 million or 26% in the first quarter as planned, compared with the same period a year earlier.
- An extensive stratigraphic test well program was completed in the first quarter with 426 gross wells drilled, primarily in the oil sands.

"Cenovus continues to deliver predictable and reliable performance which emphasizes the value of our integrated oil strategy," said Brian Ferguson, Cenovus President & Chief Executive Officer. "Production from our oil sands and conventional oil projects continues to increase and we're seeing value from the completed coker expansion at the Wood River Refinery and strong refining margins. We've delivered another strong quarter and we expect to see this performance continue throughout 2012."

Financial & Production Summary

(for the period ended March 31) (\$ millions, except per share amounts)	2012 Q1	2011 Q1	% change
Cash flow ¹	904	693	30
Per share diluted	1.19	0.91	
Operating earnings ¹	340	209	63
Per share diluted	0.45	0.28	
Net earnings	426	47	806
Per share diluted	0.56	0.06	
Capital investment ²	900	713	26
Production (before royalties)			
Foster Creek (bbls/d)	57,214	57,744	-1
Christina Lake (bbls/d)	24,733	9,084	172
Foster Creek & Christina Lake total (bbls/d)	81,947	66,828	23
Pelican Lake (bbls/d)	20,730	21,360	-3
Other conventional oil & NGLs (bbls/d)	54,173	49,167	10
Total oil & NGLs production (bbls/d)	156,850	137,355	14
Natural gas (MMcf/d)	636	652	-2

¹ Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the Earnings Reconciliation Summary.

² Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Calgary, Alberta (April 25, 2012) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered a strong first quarter with production increases from both oil sands and conventional oil operations. This production growth, together with strong refining results, contributed significantly to generating higher cash flow. The company also continued to invest in the development of its oil assets, and increased capital investment compared with the same period last year.

Combined production from the Foster Creek and Christina Lake oil sands properties increased 23% to approximately 82,000 bbls/d net, while total oil and NGLs production grew 14% to nearly 157,000 bbls/d net, compared with the same period a year earlier. Christina Lake continues to benefit from the strong start of production from phase C in the third quarter of 2011. That success is attributed to the high quality of the reservoir and the accelerated start-up techniques developed by Cenovus that decrease the amount of time between steaming the reservoir and producing first oil. Foster Creek continues to demonstrate reliable performance and is operating efficiently, with average production in the quarter within 95% of its current gross production capacity of 120,000 bbls/d.

“Cenovus’s ability to deliver consistent growth in oil sands production demonstrates how we balance the strength of the manufacturing approach we take to expand our operations with innovation and continuous improvement,” Ferguson said. “We will continue to look for ways to bring these expansion phases on even more efficiently. This is a key element in our focus on growing shareholder value.”

Growth also continued at the company’s conventional oil properties, where production from the Lower Shaunavon and Bakken tight oil plays more than doubled to nearly 6,900 bbls/d when compared with the same period a year earlier. Conventional oil production in Alberta also grew, increasing 6% to almost 30,000 bbls/d. Cenovus is continuing to assess the potential of new conventional oil projects on its existing lands in southern Alberta and is seeing the production benefit of the company’s decision to shift capital investment to oil from natural gas. The company continues to execute a drilling program to take advantage of tight oil opportunities. Incremental production from these assets was about 2,300 bbls/d in the first quarter.

Cash flow for the quarter was \$904 million, an increase of 30% when compared with the same period a year earlier. Cash flow benefited from increased oil production and higher oil prices, as well as increased refining throughput and strong refining margins. Oil production generated \$684 million, or nearly two-thirds of operating cash flow in the quarter. Cenovus received an average realized oil price, including hedging, of \$72.54 per barrel (bbl) in the quarter, compared with \$62.63/bbl in the first quarter of 2011. Operating cash flow from the refining business represented about one-quarter of the total operating cash flow, increasing \$86 million from the same period in 2011 to \$266 million. Refining benefited from a significant increase in throughput and refined product output resulting from the coker startup of the Coker and Refinery Expansion (CORE) project at the Wood River Refinery, improved utilization at the Borger Refinery and higher refining margins.

Continued benefit from integrated approach

The main benefits of integrating Cenovus’s oil sands assets with heavy oil processing capacity are reduced risk from price volatility and increased financial stability. The success of this integrated business model was apparent in the first quarter.

“While oil prices are high, Canadian heavy crude is still priced at a discount,” Ferguson said. “Although that negatively impacts the price we get for the oil we produce, our well-positioned refineries are able to benefit from lower costs for the oil they turn into refined products. That provides stable overall cash flow.”

The company’s recent expansion of the heavy oil processing capacity at its Wood River Refinery further offsets its financial exposure to heavy oil differentials as production from the oil sands increases. The Wood River Refinery continues to demonstrate increased heavy oil processing and higher clean product yields following the completion of

the coker startup of the CORE project. The refinery has demonstrated short-term rates in excess of 220,000 bbls/d of heavy oil processing capacity and an improvement to clean product yield of approximately 5%. The refinery will continue to optimize the expanded facilities throughout the year.

Cenovus expects favourable refining market conditions and discounted Canadian heavy oil will continue to deliver strong operating cash flow from the refineries for the rest of the year. The company anticipates refining operating cash flow during the second quarter to range between \$300 million and \$400 million, excluding inventory adjustments. On a full-year basis, Cenovus has updated its refining operating cash flow guidance to range between \$900 million and \$1.2 billion using a \$20.50 market crack spread assumption. Guidance has also been updated to reflect new cash flow ranges, as well as royalties. The updated guidance is available at www.cenovus.com.

Capital investment increased

As planned, Cenovus increased capital investment in the first quarter to \$900 million, 26% more than the same period last year. Oil sands capital investment of nearly \$500 million focused on the expansions at Christina Lake and Foster Creek and the drilling of stratigraphic test wells. Cenovus invested \$355 million in its conventional oil properties. This included increased infill drilling at Pelican Lake to support expansion of the polymer flood, drilling new oil wells in Alberta, as well as facility construction and well completions in the Lower Shaunavon and Bakken operations. Capital investment for refining in the first quarter was significantly lower in 2012 when compared with the same period a year earlier, mainly due to the completion of the coker construction of the CORE project at the Wood River Refinery in the fourth quarter of 2011.

Stratigraphic test well drilling program complete

Cenovus completed another extensive stratigraphic test well program in the first quarter, drilling 426 gross wells to further assess and unlock the value of the company's resource base. More than 60% of these wells were drilled in Cenovus's emerging oil sands projects to gather data on reservoir quality and support regulatory applications. The stratigraphic test wells drilled at Foster Creek and Christina Lake will be used to support the next phases of expansion.

"Cenovus expects decades of growth ahead in the oil sands," Ferguson said. "Results from our drilling program continue to support our goal of growing Cenovus's net oil sands production to 400,000 barrels per day by the end of 2021."

IMPORTANT NOTE: Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS). See the Advisory for definitions of non-GAAP measures used in this quarterly report.

Oil Projects

Daily production ¹							
(Before royalties) (Mbbbls/d)	2012	2011					2010
	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands							
Foster Creek	57	55	55	56	50	58	51
Christina Lake	25	12	20	10	8	9	8
Oil sands total	82	67	75	66	58	67	59
Conventional oil							
Pelican Lake	21	20	21	20	19	21	23
Weyburn	17	16	17	16	15	17	17
Other conventional oil & NGLs	38	31	32	31	29	32	31
Conventional total	75	68	70	67	64	71	70
Total oil & NGLs	157	134	144	133	122	137	129

¹ Totals may not add due to rounding.

Oil sands

Foster Creek and Christina Lake

Cenovus's oil sands properties in northern Alberta offer opportunities for substantial growth. The Foster Creek and Christina Lake operations use steam-assisted gravity drainage (SAGD) to drill and pump the oil to the surface. These two projects are operated by Cenovus and jointly owned with ConocoPhillips.

Production

- Production at Foster Creek and Christina Lake increased 23% in the first quarter from the same period a year earlier.
- Christina Lake production averaged close to 25,000 bbls/d net in the quarter, almost tripling production from the first quarter of 2011 and reached a production high of more than 29,000 bbls/d net in the quarter. The company's work to develop new technologies that accelerate the initial start-up of production from well pairs helped in the industry-leading ramp up of production from phase C.
- The company continues to market a portion of its oil from Christina Lake as Christina Dilbit Blend (CDB), a bitumen blend established in late 2011 to address the increase in production at Christina Lake. CDB is priced at a discount to Western Canadian Select (WCS). The blend has been well-received by refineries and the company anticipates the CDB differential to WCS will narrow as CDB gains acceptance with a wider base of refining customers. On a per barrel of bitumen basis for the first quarter, CDB netbacks were positively impacted by sales to the U.S. Gulf Coast market but offset by higher blending ratio requirements related to the accelerated production growth.
- Foster Creek continues to demonstrate reliable performance and produced more than 57,000 bbls/d net in the quarter, within 95% of its current production capacity.
- About 12% of current production at Foster Creek comes from 48 wells using Cenovus's Wedge Well™ technology. These single horizontal wells, drilled between existing SAGD well pairs, have the potential to increase overall recovery from the reservoir by as much as 10% to 15%, while reducing the steam to oil ratio (SOR). An additional 11 of these wells are waiting to be brought on production later this year and the company plans to drill another eight wells using this technology at Foster Creek by year end. Christina Lake

is also starting to benefit from the use of the company's Wedge Well™ technology with four of these wells now producing.

Expansions

- Combined capital investment at Foster Creek and Christina Lake in the first quarter was \$286 million, an increase of almost 36% compared with the same period a year earlier. This included spending on stratigraphic test wells and development of expansion phases, including site preparation and facility construction.
- At Christina Lake, construction of phase D is more than three-quarters complete and production is expected in the fourth quarter of this year. Construction of phase E is more than 40% complete, with initial production anticipated for the fourth quarter of 2013. Site preparation also continues for phase F.
- At Foster Creek, the company continues to work on the fabrication and facility construction for phase F, earthworks and site preparation for phase G and design engineering for phase H.

Operating costs and royalties

- Operating costs at Christina Lake were \$15.33/bbl in the first quarter, a 20% decrease from \$19.09/bbl in the same period a year earlier due to the significant increase in production. Operating costs were higher than anticipated in the quarter, due to increased workovers and higher workforce and maintenance costs. Cenovus expects operating costs at Christina Lake to be within the guidance range of \$13.00/bbl to \$14.35/bbl over the year. Non-fuel operating costs at Christina Lake were \$12.86/bbl in the quarter compared with \$16.26/bbl in the first quarter of 2011, a 21% decrease due to the start of production from phase C.
- Operating costs at Foster Creek averaged \$12.85/bbl in the first quarter, a 13% increase from \$11.40/bbl in the same period last year. There were power outages at the plant during the quarter, which impacted production and contributed to higher operating costs. Foster Creek experienced increased workovers, repairs and maintenance, completion work and higher staffing levels to prepare for future expansions, partially offset by decreased fuel and chemical costs. The company expects operating costs at Foster Creek to be within the guidance range of \$11.25/bbl to \$12.45/bbl over the year. Non-fuel operating costs at Foster Creek were \$10.72/bbl in the first quarter compared with \$8.53/bbl in the same period a year earlier, a 26% increase.
- Christina Lake's average royalty rate in the quarter was 7.0%, compared with an average royalty rate of 4.8% for the same period a year earlier due to higher prices for West Texas Intermediate (WTI) crude oil, which has a direct impact on royalty rates.
- Foster Creek's average royalty rate was 13.9% in the first quarter of 2012 compared with an average royalty rate of 21.2% in the same period of 2011. The reduction was primarily due to increased capital investment in the quarter and approval from the Alberta Department of Energy in the second quarter of 2011 to include capital investment for expansion phases F, G and H as part of the royalty calculation.

Steam to oil ratios (SORs)

- Cenovus continued to achieve some of the best SORs in the industry with an average ratio of approximately 2.1 at Christina Lake and Foster Creek in the first quarter. This means approximately 2.1 barrels of steam are needed for every barrel of oil produced. A lower SOR means less natural gas is used to create the steam, which results in reduced capital and operating costs, fewer emissions and lower water usage.

Future projects

Cenovus has an enormous opportunity to deliver increased shareholder value through production growth from its oil sands assets in the Athabasca region of northern Alberta, most of which are undeveloped. The company has identified 10 emerging projects and continues to assess its resources to prioritize development plans and support regulatory applications. Cenovus currently has projects with total expected gross production of 400,000 bbls/d moving through the regulatory process.

- The regulatory application for the Narrows Lake project, which is jointly owned with ConocoPhillips, is being reviewed by the regulators and Cenovus anticipates receiving approvals in the second quarter. The application includes the option of using a combination of SAGD and solvent aided process (SAP) for oil production. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d. Provided that approvals are received as anticipated, construction is expected to start later this year with initial production expected in 2016.
- The joint regulatory application and environmental impact assessment for a commercial SAGD project at Grand Rapids in the Greater Pelican Region is also being reviewed by the regulators. The company drilled a second well pair in the first quarter as part of the pilot project in the area, which began in 2010. First production from the commercial project is anticipated in 2017, if approvals are received as expected. The company believes Grand Rapids has the potential to reach production capacity of 180,000 bbls/d.
- The revised joint regulatory application and environmental impact assessment for the Telephone Lake project in the Borealis Region is also being reviewed by the regulators. The application updates the expected production capacity to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007. The company is continuing its search for a strategic transaction to support development of the project.
- Cenovus continued to progress the Telephone Lake dewatering pilot project during the first quarter and expects to start water production and air injection in the second quarter of 2012. The pilot is designed to test the efficiency of removing the non-potable water sitting on top of the bitumen in the reservoir, which is anticipated to reduce the SOR for the commercial project.

Conventional oil

Pelican Lake

Cenovus produces heavy oil from the Wabiskaw formation at its wholly-owned Pelican Lake operation in the Greater Pelican Region, about 300 kilometres north of Edmonton. While this property produces conventional heavy oil, it's managed as part of Cenovus's oil sands segment. Since 2006, polymer has been injected along with the waterflood to enhance production from the reservoir. Based on reservoir performance of the polymer flood, the company has initiated a new multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d by the end of 2016.

- Work to expand the polymer flood at Pelican Lake is ongoing. Production averaged almost 21,000 bbls/d in the quarter, a 3% decrease from the same period in 2011 due to natural declines and reduced operating pressures and shut-ins, which were required to complete infill drilling between existing wells.
- Cenovus is beginning to see production increases from the infill drilling and plans to drill between 1,300 and 1,400 wells in the next five to seven years to expand the polymer flood.
- Cenovus is also planning to build a new battery to support the expansion, with construction slated to begin in 2013.
- Operating costs at Pelican Lake averaged \$16.05/bbl in the quarter, a 5% increase from \$15.35/bbl in the first quarter of 2011 due to increased workovers, higher staffing levels to support the expansion and higher electricity costs, partially offset by decreased chemical costs.
- Pelican Lake's average royalty rate was 4.5% in the first quarter of 2012 compared with an average royalty rate of 13.9% in the same period of 2011. The reduction was primarily due to the increase of capital investment to expand the polymer flood.

Other conventional

In addition to Pelican Lake, Cenovus has extensive oil operations in Alberta and Saskatchewan. These include the established Weyburn operation that uses carbon dioxide (CO₂) to enhance oil recovery, the emerging Bakken and Lower Shaunavon tight oil assets in southern Saskatchewan as well as established properties in southern Alberta.

Cenovus is targeting oil production from these properties to reach between 65,000 bbls/d and 75,000 bbls/d by the end of 2016.

- Production from the company's conventional oil properties in southern Alberta was nearly 30,000 bbls/d, an increase of 6% from a year earlier, due to successful drilling programs and fewer weather-related issues.
- Cenovus continues to shift its focus from natural gas to oil production. The company continues to execute a drilling program to take advantage of tight oil opportunities and has seen incremental production from these assets of about 2,300 bbls/d in the first quarter.
- The Weyburn operation produced nearly 17,000 bbls/d net in the first quarter, which is consistent with production over the same period a year earlier.
- Lower Shaunavon production averaged approximately 4,100 bbls/d in the first quarter, almost one and a half times higher than the same period a year earlier. Cenovus has 87 horizontal wells and one vertical well producing in Lower Shaunavon.
- The company's Bakken operation had average oil production of more than 2,700 bbls/d in the quarter, including royalty interest volumes. Cenovus was operating 29 wells in the Bakken area at the end of the first quarter.
- Operating costs for Cenovus's conventional oil operations, excluding Pelican Lake, increased 14% to \$15.74/bbl in the first quarter compared to the same period a year earlier. This was mainly due to increased workover activity and higher waste and fluid handling costs. The company expects these costs to decrease through the year as facilities in Shaunavon are commissioned.

Natural Gas

(Before royalties) (MMcf/d)	Daily production						
	2012		2011				2010
	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural Gas ¹	636	656	660	656	654	652	737

¹ 2010 production includes a contribution from non-core assets sold in the third quarter of 2010.

Cenovus has a solid base of established, reliable natural gas properties in Alberta. These assets are an important component of the company's financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations because natural gas fuels the company's oil sands and refining operations.

- Natural gas production in the first quarter was approximately 636 million cubic feet per day (MMcf/d), a 2% decline from the same period in the previous year. Production was positively impacted by mild weather resulting in fewer outages this quarter, offset by the divestiture of a non-core property early in the quarter, as well as expected natural declines. Cenovus anticipates managing an annual natural decline rate of 10% to 15% for its natural gas production.
- Cenovus's average realized sales price for natural gas, including hedges, was \$3.53 per thousand cubic feet (Mcf) in the quarter compared with \$4.71 per Mcf in the same period a year earlier.
- Cenovus continues to manage declines in natural gas volumes, targeting a long-term production level of between 400 MMcf/d and 500 MMcf/d to match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining

Cenovus's refining operations include the Wood River Refinery in Illinois and the Borger Refinery in Texas, which are jointly owned with the operator, ConocoPhillips.

- In the first quarter, the two refineries produced 465,000 bbls/d of refined products, an increase of 82,000 bbls/d compared with the same period a year ago as a result of increased throughput attributable to the CORE project coker startup at the Wood River Refinery and improved operating performance at the Borger Refinery.
- Combined total crude oil runs at the Wood River Refinery and Borger Refinery averaged 445,000 bbls/d for the quarter, an increase of 23% when compared with the same period a year earlier.
- Canadian heavy crude processed at the Wood River Refinery in the quarter averaged approximately 171,000 bbls/d, more than 80% higher than the same quarter last year. The Wood River Refinery has demonstrated heavy oil processing capacity rates in excess of 220,000 bbls/d.
- Total processing capability of heavy Canadian crudes will be dependent upon the quality of available crudes and will be optimized to maximize economic benefit. The total gross heavy crude processing capacity at the Wood River Refinery is expected to be in the range of 200,000 bbls/d to 220,000 bbls/d. Combined with the 35,000 bbls/d of gross heavy crude refining capacity at the Borger Refinery, the total heavy crude oil refining capacity of the two refineries is expected to be approximately 235,000 bbls/d to 255,000 bbls/d gross.
- First quarter operating cash flow from refining operations was \$266 million, an increase of 48% compared with the same period last year. This was primarily due to increases in throughput and refined product output, increased heavy oil processing and strong refining margins as a result of high market crack spreads and advantaged pricing for West Texas Intermediate (WTI) based crude feedstock.
- Cenovus's operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's refining operating cash flow in the first quarter would have been \$4 million lower than under FIFO, compared with \$15 million lower in 2011.

Financial

Dividend

The Cenovus Board of Directors declared a second quarter dividend of \$0.22 per share, payable on June 29, 2012 to common shareholders of record as of June 15, 2012. Based on the April 24, 2012 closing share price on the Toronto Stock Exchange of \$34.13, this represents an annualized yield of about 2.6%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to the dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging Strategy

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

In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 125 MMcf/d of natural gas is expected to be consumed at the company's SAGD and refinery operations, which is offset by the natural gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's hedge positions at March 31, 2012 include:

- approximately 65% of expected 2012 natural gas production hedged; 130 MMcf/d at an average NYMEX price of US\$5.96/Mcf and 127 MMcf/d at an average AECO price of C\$4.50/Mcf, plus 125 MMcf/d of internal usage
- approximately 30% of expected 2012 oil production hedged, with 24,800 bbls/d at a WTI price of US\$98.72/bbl and an additional 24,500 bbls/d at an average WTI price of C\$99.47/bbl
- 166 MMcf/d of natural gas hedged for 2013 at an average NYMEX price of US\$4.64/Mcf, plus internal usage
- 10,000 bbls/d of oil production hedged for 2013 at an average WTI price of US\$102.62/bbl and an additional 10,000 bbls/d at an average WTI price of C\$103.26/bbl
- no fixed price commodity hedges in place for 2014.

Financial Highlights

- Cash flow in the first quarter of 2012 was \$904 million, or \$1.19 per share diluted, compared with \$693 million, or \$0.91 per share diluted, the same period a year earlier.
- Operating earnings in the quarter were \$340 million, or \$0.45 per share diluted, compared with \$209 million, or \$0.28 per share diluted, for the same period last year.
- Cenovus's realized after-tax hedging gains were \$23 million in the quarter. Cenovus received an average realized price, including hedging, of \$72.54/bbl for its oil in the quarter, compared with \$62.63/bbl in the first quarter of 2011. The average realized price, including hedging, for natural gas was \$3.53/Mcf, compared with \$4.71/Mcf in the same period a year earlier.
- Cenovus recorded income tax expense of \$168 million, a \$128 million increase over the previous year, primarily due to the increase in earnings in both Canada and the U.S.
- Cenovus's net earnings for the quarter were \$426 million compared with \$47 million in the same period a year earlier. Net earnings were positively affected by sales volumes for oil, strong refining results and an unrealized after-tax risk management gain of \$48 million.
- Capital investment during the quarter was \$900 million as planned, a 26% increase compared with the same period a year earlier as the company continues to advance development of its oil opportunities.
- General and administrative expenses decreased about 18% in the first quarter, compared with the same period a year earlier. This is primarily due to lower long-term incentive expenses partially offset by increased office support and information technology costs.
- Over the long term, Cenovus targets a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At March 31, 2012, the company's debt to capitalization ratio was 28% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.0 times.

Earnings reconciliation summary		
(for the period ended March 31) (\$ millions, except per share amounts)	2012 Q1	2011 Q1
Net earnings		
Add back (losses) & deduct gains: Per share diluted	426 0.56	47 0.06
Unrealized mark-to-market hedging gain (loss), after-tax	48	-201
Non-operating foreign exchange gain (loss), after-tax	38	39
Operating earnings Per share diluted	340 0.45	209 0.28

Management's Discussion and Analysis

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.

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.

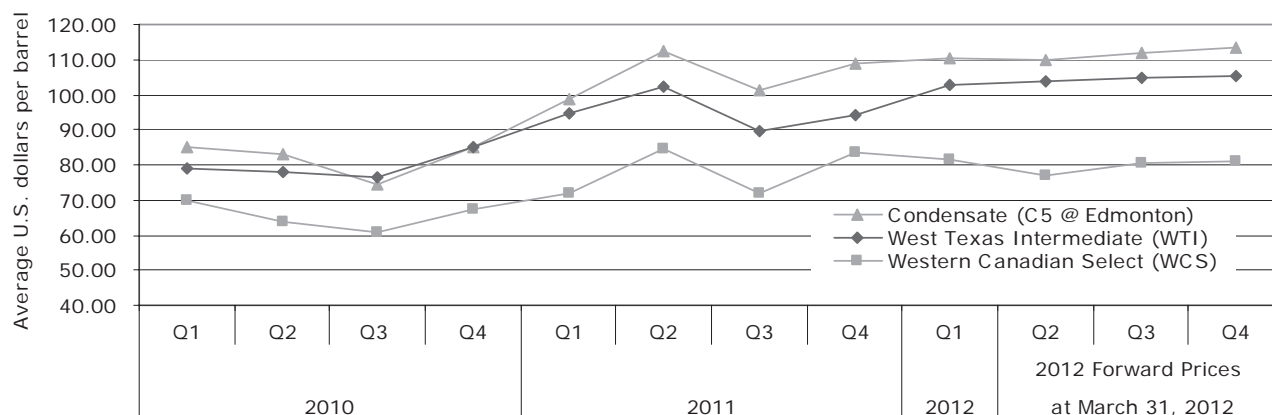
Selected Benchmark Prices and Exchange Rates

	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.

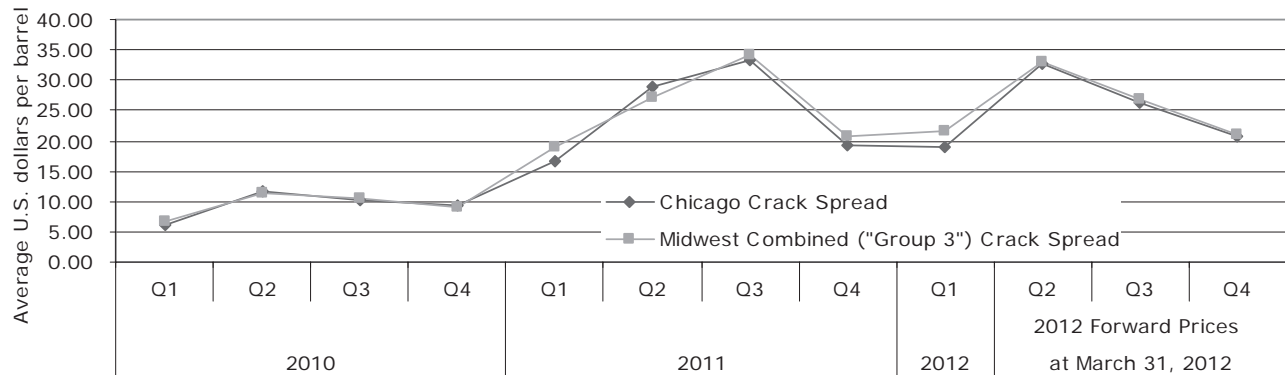
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In the first quarter of 2012, the average WTI-WCS differential widened substantially compared to the fourth 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.

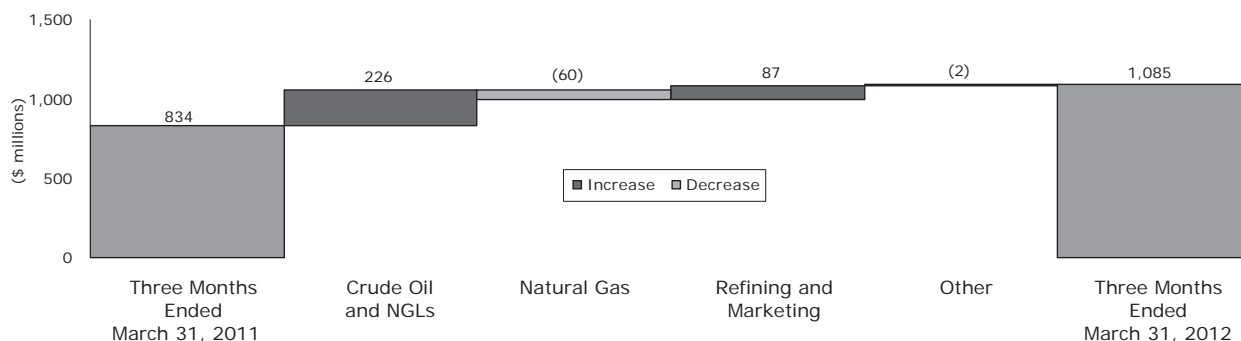
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

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.

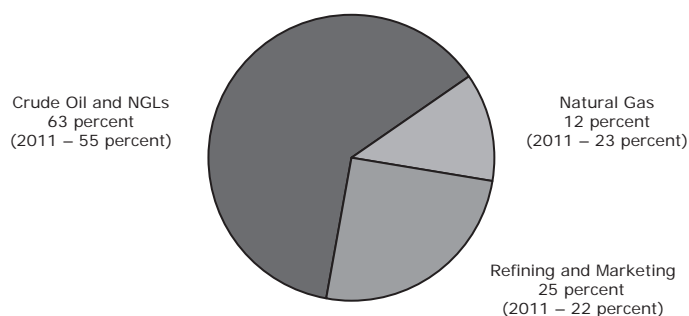
Operating Cash Flow Variance for the Three Months Ended March 31, 2012 compared to March 31, 2011



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.



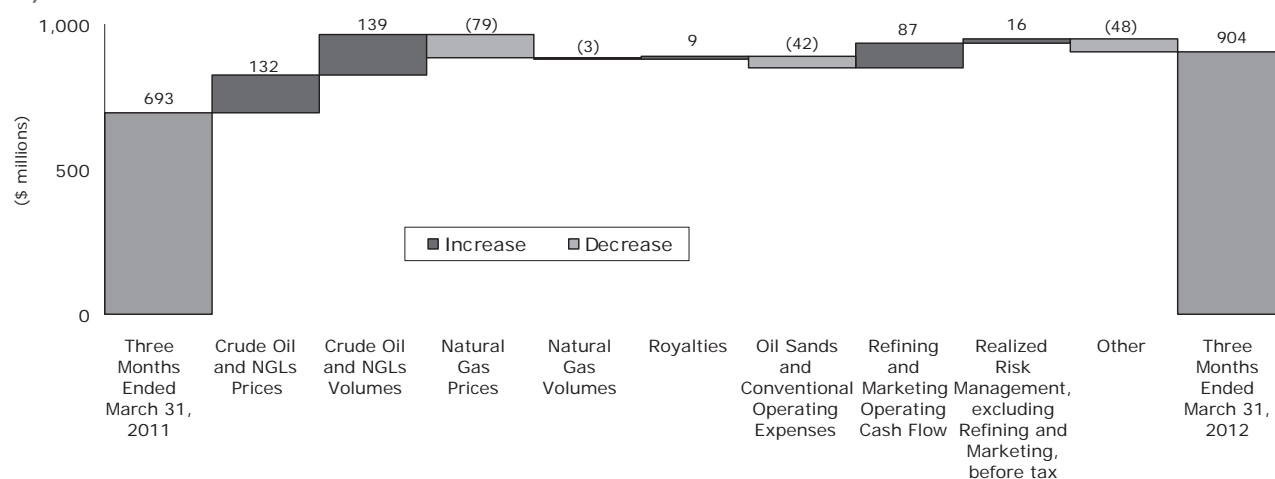
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

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

(millions of dollars)	Three Months Ended March 31,	
	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

(millions of dollars)	Three Months Ended March 31,	
	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.

(millions of dollars)	Three Months Ended March 31,	
	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

(millions of dollars)	Three Months Ended March 31,					
	2012			2011		
	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

(barrels per day)	2012	2011				2010			
	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

(MMcf per day)	2012	2011				2010			
	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 divestiture 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 (\$/bbl)	Natural Gas (\$/Mcf)	Crude Oil & NGLs (\$/bbl)	Natural Gas (\$/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

(millions of dollars)	Three Months Ended March 31,	
	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

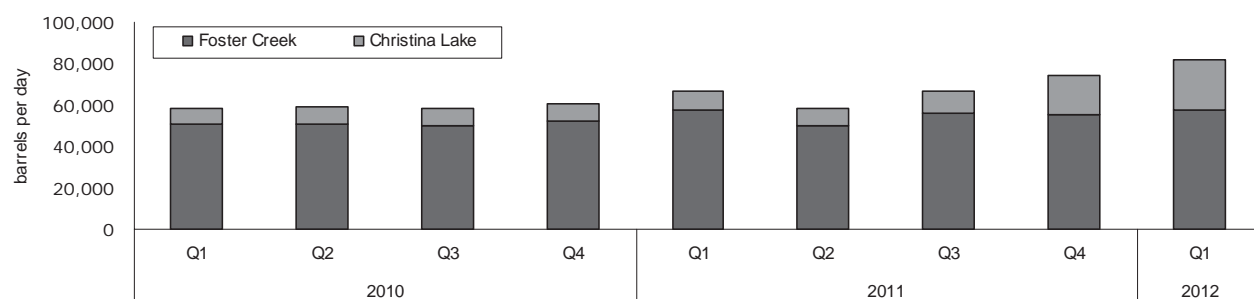
(millions of dollars)	Three Months Ended	Price	Volume	Royalties	Condensate ⁽¹⁾	Three Months Ended
	March 31, 2011					March 31, 2012
	\$ 702	78	100	17	125	\$ 1,022

⁽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

(millions of dollars)	Three Months Ended March 31,	
	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

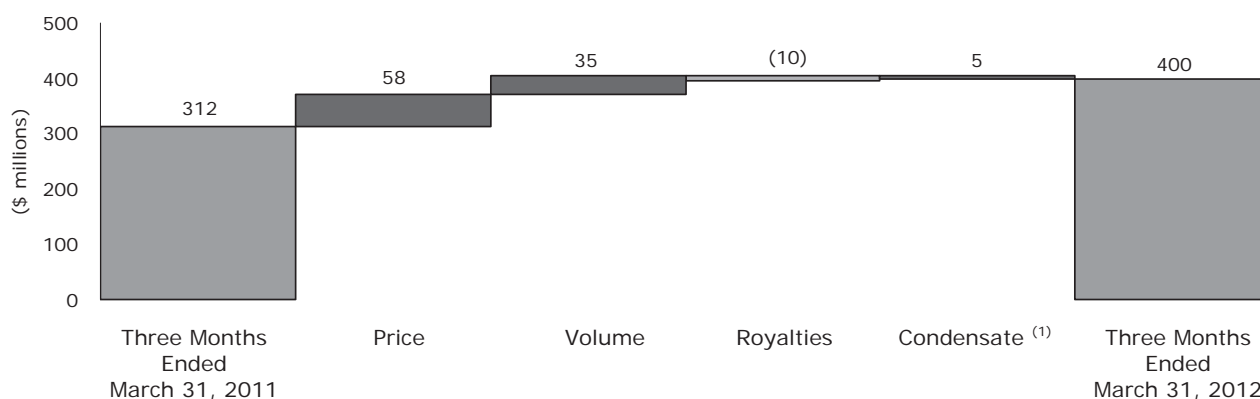
Financial Results

(millions of dollars)	Three Months Ended March 31,	
	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

(barrels per day)	Three Months Ended March 31,		
	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.

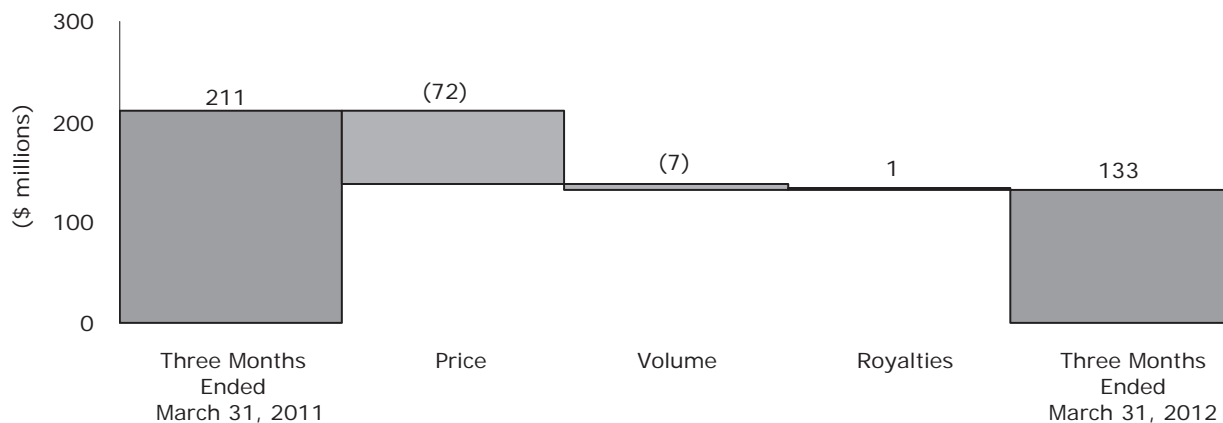
Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased by \$4 million in the first quarter of 2012 as the \$63 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, was almost offset by the \$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

(\$ millions)	Three Months Ended March 31,	
	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

(net wells)	Three Months Ended March 31,	
	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 (Mbbbls/d)	452	452
Crude oil runs (Mbbbls/d)	445	362
Crude utilization (percent)	98	80
Refined products (Mbbbls/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

(millions of dollars)	Three Months Ended March 31,	
	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

(millions of dollars)	Three Months Ended March 31,	
	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:

(millions of dollars)	Three Months Ended March 31,	
	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

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

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

(millions of dollars except percent amounts)	Three Months Ended March 31,	
	2012	2011
Current tax		
Canada	\$ 62	\$ 41
United States	12	-
Total current tax	74	41
Deferred tax	94	(1)
Income tax expense	<u>\$ 168</u>	<u>\$ 40</u>
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

(millions of dollars)	Three Months Ended March 31,	
	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.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended March 31,
(\$ millions, except per share amounts)

	Notes	Three Months Ended	
		2012	2011
Revenues	1		
Gross Sales		4,686	3,631
Less: Royalties		122	131
		<u>4,564</u>	<u>3,500</u>
Expenses	1		
Purchased product		2,589	1,943
Transportation and blending		494	358
Operating		414	370
Production and mineral taxes		10	8
(Gain) loss on risk management	19	(93)	254
Depreciation, depletion and amortization		400	306
General and administrative		93	113
Finance costs	3	113	117
Interest income	4	(29)	(32)
Foreign exchange (gain) loss, net	5	(16)	(23)
Other (income) loss, net		(5)	(1)
		<u>594</u>	<u>87</u>
Earnings Before Income Tax			
Income tax expense	6	168	40
		<u>426</u>	<u>47</u>
Net Earnings			
Other Comprehensive Income (Loss), Net of Tax			
Foreign currency translation adjustment		(21)	(23)
		<u>405</u>	<u>24</u>
Comprehensive Income			
Net Earnings per Common Share	7		
Basic		0.56	0.06
Diluted		0.56	0.06

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
(\$ millions)

	Notes	March 31, 2012	December 31, 2011
Assets			
Current Assets			
Cash and cash equivalents		460	495
Accounts receivable and accrued revenues		1,360	1,405
Current portion of Partnership Contribution Receivable		371	372
Inventories	8	1,309	1,291
Risk management	19	258	232
Assets held for sale	9	-	116
Current Assets		3,758	3,911
Exploration and Evaluation Assets	1,10	1,156	880
Property, Plant and Equipment, net	1,11	14,522	14,324
Partnership Contribution Receivable		1,695	1,822
Risk Management	19	112	52
Income Tax Receivable		29	29
Other Assets		37	44
Goodwill	1	1,132	1,132
Total Assets		22,441	22,194
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		2,510	2,579
Income tax payable		212	329
Current portion of Partnership Contribution Payable		371	372
Short-term borrowings	12	270	-
Risk management	19	87	54
Liabilities related to assets held for sale	9	-	54
Current Liabilities		3,450	3,388
Long-Term Debt	13	3,465	3,527
Partnership Contribution Payable		1,725	1,853
Risk Management	19	6	14
Decommissioning Liabilities	14	1,797	1,777
Other Liabilities		106	128
Deferred Income Taxes		2,191	2,101
Total Liabilities		12,740	12,788
Shareholders' Equity		9,701	9,406
Total Liabilities and Shareholders' Equity		22,441	22,194

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

(\$ millions)

	Share Capital (Note 15)	Paid in Surplus	Retained Earnings	AOCI*	Total
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	47	-	47
Other comprehensive income (loss)	-	-	-	(23)	(23)
Total comprehensive income (loss) for the year	-	-	47	(23)	24
Common shares issued under option plans	42	-	-	-	42
Stock-based compensation expense	-	5	-	-	5
Dividends on common shares	-	-	(151)	-	(151)
Balance as at March 31, 2011	3,758	4,088	421	48	8,315
Balance as at December 31, 2011	3,780	4,107	1,400	119	9,406
Net earnings	-	-	426	-	426
Other comprehensive income (loss)	-	-	-	(21)	(21)
Total comprehensive income (loss) for the year	-	-	426	(21)	405
Common shares issued under option plans	42	-	-	-	42
Stock-based compensation expense	-	14	-	-	14
Dividends on common shares	-	-	(166)	-	(166)
Balance as at March 31, 2012	3,822	4,121	1,660	98	9,701

* Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended March 31,
(\$ millions)

	Notes	Three Months Ended	
		2012	2011
Operating Activities			
Net earnings		426	47
Depreciation, depletion and amortization		400	306
Deferred income taxes	6	94	(1)
Unrealized (gain) loss on risk management	19	(64)	268
Unrealized foreign exchange (gain) loss	5	(31)	(36)
Unwinding of discount on decommissioning liabilities	3,14	21	18
Other		58	91
		<u>904</u>	<u>693</u>
Net change in other assets and liabilities		(32)	(29)
Net change in non-cash working capital		(207)	(33)
Cash From Operating Activities		<u>665</u>	<u>631</u>
Investing Activities			
Capital expenditures – exploration and evaluation assets	10	(271)	(225)
Capital expenditures – property, plant and equipment	11	(637)	(504)
Proceeds from divestiture of assets		66	2
Net change in investments and other		(2)	(10)
Net change in non-cash working capital		12	53
Cash (Used in) Investing Activities		<u>(832)</u>	<u>(684)</u>
Net Cash Provided (Used) before Financing Activities		<u>(167)</u>	<u>(53)</u>
Financing Activities			
Net issuance (repayment) of short-term borrowings		273	250
Proceeds on issuance of common shares		31	31
Dividends paid on common shares	7	(166)	(151)
Cash From (Used in) Financing Activities		<u>138</u>	<u>130</u>
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		<u>(6)</u>	<u>2</u>
Increase (Decrease) in Cash and Cash Equivalents		<u>(35)</u>	<u>79</u>
Cash and Cash Equivalents, Beginning of Period		<u>495</u>	<u>300</u>
Cash and Cash Equivalents, End of Period		<u>460</u>	<u>379</u>

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at #4000, 421 - 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. Information on the Company's basis of presentation for these financial statements is found in Note 2.

The Company's reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by 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.

The tabular financial information which follows presents the segmented information first by segment, then by product and geographic location.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended March 31, 2012

A) Results of Operations – Segment and Operational Information

For the three months ended March 31,	<u>Oil Sands</u>		<u>Conventional</u>		<u>Refining and Marketing</u>	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	1,102	802	592	573	2,992	2,282
Less: Royalties	66	84	56	47	-	-
	<u>1,036</u>	<u>718</u>	<u>536</u>	<u>526</u>	<u>2,992</u>	<u>2,282</u>
Expenses						
Purchased product	-	-	-	-	2,589	1,969
Transportation and blending	450	321	44	37	-	-
Operating	151	118	134	125	130	128
Production and mineral taxes	-	-	10	8	-	-
(Gain) loss on risk management	14	20	(49)	(39)	6	5
Operating Cash Flow	<u>421</u>	<u>259</u>	<u>397</u>	<u>395</u>	<u>267</u>	<u>180</u>
Depreciation, depletion and amortization	115	86	236	195	38	16
Segment Income (Loss)	<u>306</u>	<u>173</u>	<u>161</u>	<u>200</u>	<u>229</u>	<u>164</u>

For the three months ended March 31,	<u>Corporate and Eliminations</u>		<u>Consolidated</u>	
	2012	2011	2012	2011
Revenues				
Gross Sales	-	(26)	4,686	3,631
Less: Royalties	-	-	122	131
	-	(26)	<u>4,564</u>	<u>3,500</u>
Expenses				
Purchased product	-	(26)	2,589	1,943
Transportation and blending	-	-	494	358
Operating	(1)	(1)	414	370
Production and mineral taxes	-	-	10	8
(Gain) loss on risk management	(64)	268	(93)	254
	<u>65</u>	<u>(267)</u>	<u>1,150</u>	<u>567</u>
Depreciation, depletion and amortization	11	9	400	306
Segment Income (Loss)	<u>54</u>	<u>(276)</u>	<u>750</u>	<u>261</u>
General and administrative	93	113	93	113
Finance costs	113	117	113	117
Interest income	(29)	(32)	(29)	(32)
Foreign exchange (gain) loss, net	(16)	(23)	(16)	(23)
Other (income) loss, net	(5)	(1)	(5)	(1)
	<u>156</u>	<u>174</u>	<u>156</u>	<u>174</u>
Earnings Before Income Tax			594	87
Income tax expense			168	40
Net Earnings			<u>426</u>	<u>47</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2012

Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

As at	Exploration and Evaluation Assets		Property, Plant and Equipment	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Oil Sands	991	741	6,501	6,224
Conventional	165	139	4,661	4,668
Refining and Marketing	-	-	3,104	3,200
Corporate and Eliminations	-	-	256	232
Consolidated	1,156	880	14,522	14,324

As at	Goodwill		Total Assets	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Oil Sands	739	739	10,945	10,524
Conventional	393	393	5,423	5,566
Refining and Marketing	-	-	4,837	4,927
Corporate and Eliminations	-	-	1,236	1,177
Consolidated	1,132	1,132	22,441	22,194

Capital Expenditures

For the period ended March 31,	Three Months Ended	
	2012	2011
Capital		
Oil Sands	636	404
Conventional	231	176
Refining and Marketing	(2)	102
Corporate	35	31
	900	713
Acquisition Capital		
Oil Sands	-	4
Conventional	8	12
Refining and Marketing	-	-
Corporate	-	3
Total	908	732

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended March 31, 2012

B) Financial Results by Upstream Product

For the three months ended March 31,	Oil Sands		Crude Oil and NGLs Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	1,087	784	454	356	1,541	1,140
Less: Royalties	65	82	54	44	119	126
	1,022	702	400	312	1,422	1,014
Expenses						
Transportation and blending	449	321	38	27	487	348
Operating	138	107	79	63	217	170
Production and mineral taxes	-	-	9	5	9	5
(Gain) loss on risk management	18	24	7	9	25	33
Operating Cash Flow	417	250	267	208	684	458

For the three months ended March 31,	Oil Sands		Natural Gas Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	11	14	135	214	146	228
Less: Royalties	1	2	2	3	3	5
	10	12	133	211	143	223
Expenses						
Transportation and blending	1	-	6	10	7	10
Operating	9	9	54	61	63	70
Production and mineral taxes	-	-	1	3	1	3
(Gain) loss on risk management	(4)	(4)	(56)	(48)	(60)	(52)
Operating Cash Flow	4	7	128	185	132	192

For the three months ended March 31,	Oil Sands		Other Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	4	4	3	3	7	7
Less: Royalties	-	-	-	-	-	-
	4	4	3	3	7	7
Expenses						
Transportation and blending	-	-	-	-	-	-
Operating	4	2	1	1	5	3
Production and mineral taxes	-	-	-	-	-	-
(Gain) loss on risk management	-	-	-	-	-	-
Operating Cash Flow	-	2	2	2	2	4

For the three months ended March 31,	Oil Sands		Total Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	1,102	802	592	573	1,694	1,375
Less: Royalties	66	84	56	47	122	131
	1,036	718	536	526	1,572	1,244
Expenses						
Transportation and blending	450	321	44	37	494	358
Operating	151	118	134	125	285	243
Production and mineral taxes	-	-	10	8	10	8
(Gain) loss on risk management	14	20	(49)	(39)	(35)	(19)
Operating Cash Flow	421	259	397	395	818	654

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2012

C) Geographic Information

For the three months ended March 31,	Canada		United States		Consolidated	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross Sales	2,244	1,836	2,442	1,795	4,686	3,631
Less: Royalties	122	131	-	-	122	131
	<u>2,122</u>	<u>1,705</u>	<u>2,442</u>	<u>1,795</u>	<u>4,564</u>	<u>3,500</u>
Expenses						
Purchased product	543	453	2,046	1,490	2,589	1,943
Transportation and blending	494	358	-	-	494	358
Operating	290	250	124	120	414	370
Production and mineral taxes	10	8	-	-	10	8
(Gain) loss on risk management	(95)	252	2	2	(93)	254
	<u>880</u>	<u>384</u>	<u>270</u>	<u>183</u>	<u>1,150</u>	<u>567</u>
Depreciation, depletion and amortization	362	290	38	16	400	306
Segment Income (Loss)	<u>518</u>	<u>94</u>	<u>232</u>	<u>167</u>	<u>750</u>	<u>261</u>

The Oil Sands and Conventional segments operate in Canada. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third party purchases and sales of product, is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business. The Corporate and Eliminations segment is attributed to Canada with the exception of the unrealized risk management gains and losses which have been attributed to the country in which the transacting entity resides.

Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

As at	Exploration and Evaluation Assets		Property, Plant and Equipment	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Canada	1,156	880	11,418	11,124
United States	-	-	3,104	3,200
Consolidated	<u>1,156</u>	<u>880</u>	<u>14,522</u>	<u>14,324</u>
As at	Goodwill		Total Assets	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Canada	1,132	1,132	17,863	17,536
United States	-	-	4,578	4,658
Consolidated	<u>1,132</u>	<u>1,132</u>	<u>22,441</u>	<u>22,194</u>

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these interim Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C\$ or \$ are to Canadian dollars and references to US\$ are to U.S. dollars.

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "Interim Financial Reporting" ("IAS 34") and have been prepared following the same accounting policies and method of computation as the annual Consolidated Financial Statements for the year ended December 31, 2011. The disclosures provided below are incremental to those included with the annual Consolidated Financial Statements. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2011, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee on April 24, 2012.

3. FINANCE COSTS

For the period ended March 31,	Three Months Ended	
	2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	53	54
Interest Expense – Partnership Contribution Payable	32	36
Unwinding of Discount on Decommissioning Liabilities	21	18
Other	7	9
	<u>113</u>	<u>117</u>

4. INTEREST INCOME

For the period ended March 31,	Three Months Ended	
	2012	2011
Interest Income – Partnership Contribution Receivable	(28)	(31)
Other	(1)	(1)
	<u>(29)</u>	<u>(32)</u>

5. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended March 31,	Three Months Ended	
	2012	2011
Unrealized Foreign Exchange (Gain) Loss on translation of:		
U.S. dollar debt issued from Canada	(62)	(80)
U.S. dollar Partnership Contribution Receivable issued from Canada	24	41
Other	7	3
Unrealized Foreign Exchange (Gain) Loss	(31)	(36)
Realized Foreign Exchange (Gain) Loss	15	13
	<u>(16)</u>	<u>(23)</u>

6. INCOME TAXES

The provision for income taxes is as follows:

For the period ended March 31,	Three Months Ended	
	2012	2011
Current Tax		
Canada	62	41
United States	12	-
Total Current Tax	74	41
Deferred Tax	94	(1)
	<u>168</u>	<u>40</u>

7. PER SHARE AMOUNTS

A) Net Earnings per Share

For the three months ended (\$ millions, except earnings per share)	March 31, 2012			March 31, 2011		
	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	426	755.1	\$0.56	47	753.2	\$0.06
Dilutive effect of Cenovus TSARs	-	4.4		-	4.9	
Dilutive effect of NSRs	-	-		-	-	
Net earnings per share – diluted	<u>426</u>	<u>759.5</u>	<u>\$0.56</u>	<u>47</u>	<u>758.1</u>	<u>\$0.06</u>

B) Dividends per Share

The Company paid dividends of \$166 million, \$0.22 per share, for the three months ended March 31, 2012 (March 31, 2011 – \$151 million, \$0.20 per share).

The Cenovus Board of Directors declared a second quarter dividend of \$0.22 per share, payable on June 29, 2012, to common shareholders of record as of June 15, 2012.

8. INVENTORIES

As at	March 31, 2012	December 31, 2011
Product		
Refining and Marketing	1,141	1,079
Oil Sands	139	186
Conventional	1	1
Parts and Supplies	<u>28</u>	<u>25</u>
	<u>1,309</u>	<u>1,291</u>

9. ASSETS AND LIABILITIES HELD FOR SALE

Assets and liabilities classified as held for sale consisted of the following:

As at	March 31, 2012	December 31, 2011
Assets Held for Sale		
Property, plant and equipment	<u>-</u>	<u>116</u>
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	-	54
Deferred income taxes	<u>-</u>	<u>-</u>
	<u>-</u>	<u>54</u>

Non-Core Natural Gas Assets

In January 2012, the Company completed the sale of non-core natural gas assets located in Northern Alberta. A loss of \$3 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

10. EXPLORATION AND EVALUATION ASSETS

	E&E
COST	
As at December 31, 2010	713
Additions	527
Transfers to property, plant and equipment (Note 11)	(356)
Divestitures	(3)
Change in decommissioning liabilities	(1)
As at December 31, 2011	<u>880</u>
Additions	271
Transfers to property, plant and equipment (Note 11)	-
Divestitures	-
Change in decommissioning liabilities	5
As at March 31, 2012	<u><u>1,156</u></u>

Exploration and evaluation assets ("E&E assets") consist of the Company's evaluation projects which are pending the determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the three months ended March 31, 2012 include \$10 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – \$15 million).

For the three months ended March 31, 2012, no E&E assets were transferred to property, plant and equipment – development and production assets following the determination of technical feasibility and commercial viability of the projects in question (year ended December 31, 2011 – \$356 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statement of Earnings and Comprehensive Income. There were no impairment losses recorded for the three months ended March 31, 2012 and 2011.

11. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets		Refining Equipment	Other ¹	Total
	Development & Production	Other Upstream			
COST					
As at December 31, 2010	21,720	153	2,950	450	25,273
Additions	1,704	41	391	131	2,267
Transfers from E&E assets (Note 10)	356	-	-	-	356
Transfers and reclassifications	(326)	-	(5)	(2)	(333)
Change in decommissioning liabilities	403	-	10	1	414
Exchange rate movements	1	-	79	-	80
Divestitures	-	-	-	(4)	(4)
As at December 31, 2011	23,858	194	3,425	576	28,053
Additions	597	7	(2)	35	637
Transfers from E&E assets (Note 10)	-	-	-	-	-
Transfers and reclassifications	-	-	-	-	-
Change in decommissioning liabilities	17	-	-	-	17
Exchange rate movements	(1)	-	(60)	-	(61)
Divestitures	-	-	-	-	-
As at March 31, 2012	24,471	201	3,363	611	28,646
ACCUMULATED DEPRECIATION, DEPLETION AND IMPAIRMENT					
As at December 31, 2010	12,121	124	97	304	12,646
Depreciation and depletion expense	1,108	15	85	40	1,248
Transfers and reclassifications	(211)	-	(5)	-	(216)
Impairment losses	2	-	45	-	47
Exchange rate movements	1	-	3	-	4
As at December 31, 2011	13,021	139	225	344	13,729
Depreciation and depletion expense	348	3	38	11	400
Transfers and reclassifications	-	-	-	-	-
Impairment losses	-	-	-	-	-
Exchange rate movements	(1)	-	(4)	-	(5)
Divestitures	-	-	-	-	-
As at March 31, 2012	13,368	142	259	355	14,124
CARRYING VALUE					
As at December 31, 2010	9,599	29	2,853	146	12,627
As at December 31, 2011	10,837	55	3,200	232	14,324
As at March 31, 2012	11,103	59	3,104	256	14,522

1. Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.

Additions to development and production assets include internal costs directly related to the development, construction and production of oil and gas properties of \$39 million for the three months ended March 31, 2012 (December 31, 2011 – \$125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the three months ended March 31, 2012 or for the year ended December 31, 2011.

Property, plant and equipment include the following amounts in respect of assets under construction which are not subject to depreciation until put into use:

As at	March 31, 2012	December 31, 2011
Development and production	57	52
Refining equipment	72	125
Other	128	112
	<u>257</u>	<u>289</u>

Impairment

The impairment of property, plant and equipment and any subsequent reversal of such impairment losses are recognized in depreciation, depletion and amortization in the Consolidated Statement of Earnings and Comprehensive Income. There were no impairment losses recorded in the Consolidated Statement of Earnings and Comprehensive Income for the three months ended March 31, 2012 and 2011.

12. SHORT-TERM BORROWINGS

The Company had short-term borrowings in the form of commercial paper in the amount of \$270 million as at March 31, 2012 (December 31, 2011 – \$nil). The Company reserves capacity under its committed credit facility for amounts of commercial paper outstanding.

13. LONG-TERM DEBT

As at	March 31, 2012	December 31, 2011
Canadian Dollar Denominated Debt		
Revolving term debt ¹	-	-
U.S. Dollar Denominated Debt		
Revolving term debt ¹	-	-
Unsecured notes (US\$ 3,500)	3,497	3,559
	<u>3,497</u>	<u>3,559</u>
Total Debt Principal	3,497	3,559
Debt Discounts and Transaction Costs	(32)	(32)
Current Portion of Long-Term Debt	-	-
	<u>3,465</u>	<u>3,527</u>

1. Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

As at March 31, 2012, the Company is in compliance with all of the terms of its debt agreements.

14. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the future costs associated with the retirement of upstream oil and gas assets and refining facilities. The aggregate carrying amount of the obligation is as follows:

As at	March 31, 2012	December 31, 2011
Decommissioning Liabilities, Beginning of Year	1,777	1,399
Liabilities incurred	22	49
Liabilities settled	(25)	(56)
Transfers and reclassifications	3	(55)
Change in estimated future cash flows	-	146
Change in discount rate	-	218
Unwinding of discount on decommissioning liabilities	21	75
Foreign currency translation	(1)	1
Decommissioning Liabilities, End of Period	<u>1,797</u>	<u>1,777</u>

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.8 percent as at March 31, 2012 (December 31, 2011 – 4.8 percent).

15. SHARE CAPITAL

Authorized

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of First Preferred Shares and an unlimited number of Second Preferred Shares. The First and Second Preferred Shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

Issued and Outstanding

As at	March 31, 2012		December 31, 2011	
	Number of Common Shares (thousands)	Amount	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	754,499	3,780	752,675	3,716
Common Shares Issued under Stock Option Plans	1,142	42	1,824	64
Outstanding, End of Period	755,641	3,822	754,499	3,780

There were no Preferred Shares outstanding as at March 31, 2012 (December 31, 2011 – nil).

As at March 31, 2012, there were 27 million (December 31, 2011 – 30 million) common shares available for future issuance under stock option plans.

16. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("Performance TSARs"). The Performance TSARs vest and expire under the same terms and service conditions as the underlying option, and have an additional vesting requirement whereby vesting is subject to achievement of prescribed performance relative to pre-determined key measures. Performance TSARs that do not vest when eligible are forfeited.

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus Replacement TSAR and one Encana Replacement TSAR. The terms and conditions of the Cenovus and Encana Replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana Replacement TSARs based on the one day volume weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the TSX on December 2, 2009. Cenovus TSARs and

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Cenovus Replacement TSARs are measured against the Cenovus common share price while Encana Replacement TSARs are measured against the Encana common share price. The Cenovus Replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana Performance TSARs were also exchanged under the same terms as the original Encana TSARs.

As at March 31, 2012	Issued	Term (Years)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price (\$)	Closing Share Price (\$)	Units Outstanding
Encana Replacement TSARs held by Cenovus Employees	Prior to Arrangement	5	1.39	32.68	19.59	8,108
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	5	1.43	29.30	35.90	6,149
TSARs	Prior to February 17, 2010	5	1.45	29.37	35.90	6,879
TSARs	On or After February 17, 2010	7	4.95	26.72	35.90	5,274
NSRs	On or After February 24, 2011	7	<u>6.52</u>	<u>37.96</u>	<u>35.90</u>	<u>13,992</u>

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus Replacement TSARs.

NSRs

The weighted average unit fair value of NSRs granted during the three months ended March 31, 2012 was \$7.82 before considering forfeitures. The fair value of each NSR was estimated on their grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2012
Risk Free Interest Rate	1.38%
Expected Dividend Yield	2.29%
Expected Volatility ¹	28.66%
Expected Life (Years)	4.55

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize the information related to the NSRs as at March 31, 2012:

As at March 31, 2012 (thousands of units)	NSRs	Weighted Average Exercise Price (\$)
Outstanding, Beginning of Year	5,809	36.95
Granted	8,219	38.67
Exercised for common shares	(3)	35.83
Forfeited	(33)	36.70
Outstanding, End of Period	<u>13,992</u>	<u>37.96</u>
Exercisable, End of Period	<u>1,436</u>	<u>37.52</u>

The weighted average market price of Cenovus's common shares at the date of exercise during the three months ended March 31, 2012 was \$36.95.

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As at March 31, 2012 Range of Exercise Price (\$)	Outstanding NSRs (thousands of units)		
	NSRs	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price (\$)
30.00 to 39.99	13,992	6.52	37.96
	<u>13,992</u>	<u>6.52</u>	<u>37.96</u>

As at March 31, 2012 Range of Exercise Price (\$)	Exercisable NSRs (thousands of units)	
	NSRs	Weighted Average Exercise Price (\$)
30.00 to 39.99	1,436	37.52
	<u>1,436</u>	<u>37.52</u>

TSARs Held by Cenovus Employees

The Company has recorded a liability of \$91 million as at March 31, 2012 (December 31, 2011 – \$90 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2012
Risk Free Interest Rate	1.43%
Expected Dividend Yield	2.29%
Expected Volatility ¹	28.52%
Cenovus's Common Share Price	\$35.90

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at March 31, 2012 was \$71 million (December 31, 2011 – \$43 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at March 31, 2012:

As at March 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price (\$)
Outstanding, Beginning of Year	9,391	5,530	14,921	28.12
Granted	-	-	-	-
Exercised for cash payment	(625)	(781)	(1,406)	28.06
Exercised as options for common shares	(560)	(562)	(1,122)	27.55
Forfeited	(42)	(198)	(240)	26.43
Outstanding, End of Period	<u>8,164</u>	<u>3,989</u>	<u>12,153</u>	<u>28.22</u>
Exercisable, End of Period	<u>5,635</u>	<u>3,985</u>	<u>9,620</u>	<u>28.55</u>

The weighted average market price of Cenovus's common shares at the date of exercise during the three months ended March 31, 2012 was \$37.39.

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As at March 31, 2012 Range of Exercise Price (\$)	Outstanding TSARs (thousands of units)			Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total		
20.00 to 29.99	6,626	2,303	8,929	3.61	26.40
30.00 to 39.99	1,475	1,686	3,161	1.19	33.06
40.00 to 49.99	63	-	63	1.20	43.30
	8,164	3,989	12,153	2.97	28.22

As at March 31, 2012 Range of Exercise Price (\$)	Exercisable TSARs (thousands of units)			Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total	
20.00 to 29.99		4,239	2,299	26.32
30.00 to 39.99		1,333	1,686	33.08
40.00 to 49.99		63	-	43.30
		5,635	3,985	28.55

The market price of Cenovus common shares as at March 31, 2012 was \$35.90.

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana in respect of cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana Replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of \$1 million as at March 31, 2012 (December 31, 2011 – \$1 million) in the Consolidated Balance Sheets based on the fair value of each Encana Replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2012
Risk Free Interest Rate	1.32%
Expected Dividend Yield	3.30%
Expected Volatility ¹	29.02%
Encana's Common Share Price	\$19.59

1. Expected volatility has been based on the historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees as at March 31, 2012 was \$nil (December 31, 2011 – \$nil).

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The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at March 31, 2012:

As at March 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price (\$)
Outstanding, Beginning of Year	4,281	6,130	10,411	31.97
Exercised for cash payment	-	-	-	-
Exercised as options for Encana common shares	-	-	-	-
Forfeited	(29)	(214)	(243)	29.65
Expired	(824)	(1,236)	(2,060)	29.45
Outstanding, End of Period	3,428	4,680	8,108	32.68
Exercisable, End of Period	3,398	4,677	8,075	32.69

Outstanding TSARs
(thousands of units)

As at March 31, 2012 Range of Exercise Price (\$)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price (\$)
20.00 to 29.99	1,601	2,573	4,174	1.87	29.02
30.00 to 39.99	1,694	2,107	3,801	0.87	36.28
40.00 to 49.99	131	-	131	1.23	44.85
50.00 to 59.99	2	-	2	1.14	50.39
	3,428	4,680	8,108	1.39	32.68

Exercisable TSARs
(thousands of units)

As at March 31, 2012 Range of Exercise Price (\$)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price (\$)
20.00 to 29.99	1,583	2,570	4,153	29.02
30.00 to 39.99	1,682	2,107	3,789	36.29
40.00 to 49.99	131	-	131	44.85
50.00 to 59.99	2	-	2	50.39
	3,398	4,677	8,075	32.69

The market price of Encana common shares as at March 31, 2012 was \$19.59.

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus in respect of cash payments made by Cenovus to Encana's employees when these employees exercise a Cenovus Replacement TSAR for cash. No compensation expense is recognized and no further Cenovus Replacement TSARs will be granted to Encana employees.

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For the period ended March 31, 2012

The Company has recorded a liability of \$65 million as at March 31, 2012 (December 31, 2011 – \$83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

	2012
Risk Free Interest Rate	1.32%
Expected Dividend Yield	2.29%
Expected Volatility ¹	28.52%
Cenovus's Common Share Price	\$35.90

1. Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees as at March 31, 2012 was \$39 million (December 31, 2011 – \$32 million).

The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at March 31, 2012:

As at March 31, 2012 (thousands of units)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price (\$)
Outstanding, Beginning of Year	3,935	5,751	9,686	28.96
Exercised for cash payment	(1,362)	(1,838)	(3,200)	28.56
Exercised as options for common shares	(8)	(12)	(20)	26.63
Forfeited	(43)	(274)	(317)	26.66
Outstanding, End of Period	<u>2,522</u>	<u>3,627</u>	<u>6,149</u>	<u>29.30</u>
Exercisable, End of Period	<u>2,479</u>	<u>3,574</u>	<u>6,053</u>	<u>29.34</u>

The weighted average market price of Cenovus's common shares at the date of exercise during the three months ended March 31, 2012 was \$37.28.

As at March 31, 2012 Range of Exercise Price (\$)	Outstanding TSARs (thousands of units)			Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total		
20.00 to 29.99	1,336	2,160	3,496	1.86	26.30
30.00 to 39.99	1,120	1,467	2,587	0.87	33.00
40.00 to 49.99	66	-	66	1.19	42.84
	<u>2,522</u>	<u>3,627</u>	<u>6,149</u>	<u>1.43</u>	<u>29.30</u>

As at March 31, 2012 Range of Exercise Price (\$)	Exercisable TSARs (thousands of units)			Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total	
20.00 to 29.99	1,294	2,107	3,401	26.30
30.00 to 39.99	1,119	1,467	2,586	33.00
40.00 to 49.99	66	-	66	42.84
	<u>2,479</u>	<u>3,574</u>	<u>6,053</u>	<u>29.34</u>

The market price of Cenovus common shares as at March 31, 2012 was \$35.90.

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B) Performance Share Units

Cenovus has granted Performance Share Units (“PSUs”) to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of \$80 million as at March 31, 2012 (December 31, 2011 – \$55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares as at March 31, 2012. The intrinsic value of vested PSUs was \$nil as at March 31, 2012 and December 31, 2011 as PSUs are paid out upon vesting.

The following table summarizes the information related to the PSUs held by Cenovus employees as at March 31, 2012:

As at March 31, 2012

(thousands of units)

	PSUs
Outstanding, Beginning of Year	2,623
Granted	2,688
Cancelled	(37)
Units in Lieu of Dividends	28
Outstanding, End of Period	<u>5,302</u>

C) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive Deferred Share Units (“DSUs”), which are equivalent in value to a common share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of \$41 million as at March 31, 2012 (December 31, 2011 – \$35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares as at March 31, 2012. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees as at March 31, 2012:

As at March 31, 2012

(thousands of units)

	DSUs
Outstanding, Beginning of Year	1,042
Granted to Directors	61
Granted from Annual Bonus Awards	22
Units in Lieu of Dividends	7
Exercised	-
Outstanding, End of Period	<u>1,132</u>

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D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses on the Consolidated Statements of Earnings and Comprehensive Income:

For the period ended March 31,	Three Months Ended	
	2012	2011
NSRs	8	4
TSARs held by Cenovus employees	16	46
Encana Replacement TSARs held by Cenovus employees	-	19
PSUs	15	10
DSUs	6	8
Total stock-based compensation expense (recovery)	<u>45</u>	<u>87</u>

17. INTEREST IN JOINT OPERATIONS

Cenovus has a 50 percent interest in FCCL Partnership, a jointly controlled entity which is involved in the development and production of crude oil. In addition, through its interest in the general partner and a limited partner, Cenovus has a 50 percent interest in WRB Refining LP, a jointly controlled entity, which owns two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products.

These entities have been accounted for using the proportionate consolidation method with the results of operations included in the Oil Sands and Refining and Marketing segments, respectively. Summarized financial statement information for these jointly controlled entities is as follows:

Consolidated Statements of Earnings For the three months ended March 31,	FCCL Partnership ¹		WRB Refining LP ¹	
	2012	2011	2012	2011
Revenues	809	555	2,442	1,795
Expenses				
Purchased product	-	-	2,046	1,490
Operating, transportation and blending and realized gain/loss on risk management	<u>512</u>	<u>367</u>	<u>128</u>	<u>125</u>
Operating Cash Flow	<u>297</u>	<u>188</u>	<u>268</u>	<u>180</u>
Depreciation, depletion and amortization	70	49	35	16
Other expenses (income)	<u>25</u>	<u>36</u>	<u>(1)</u>	<u>(2)</u>
Net Earnings (Loss)	<u>202</u>	<u>103</u>	<u>234</u>	<u>166</u>

1. FCCL Partnership and WRB Refining LP are not separate tax paying entities. Income taxes related to the Partnerships' income are the responsibility of their respective Partners.

Consolidated Balance Sheets As at	FCCL Partnership		WRB Refining LP	
	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Cash and Cash Equivalents	205	145	162	166
Other Current Assets	798	792	1,271	1,236
Long-term Assets	6,986	6,864	3,095	3,188
Current Liabilities	339	317	717	759
Long-term Liabilities	<u>81</u>	<u>83</u>	<u>72</u>	<u>73</u>

18. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt includes the Company's short-term borrowings plus long-term debt, including the current portion. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as 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.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at	March 31, 2012	December 31, 2011
Short-Term Borrowings	270	-
Long-Term Debt	3,465	3,527
Debt	3,735	3,527
Shareholders' Equity	9,701	9,406
Total Capitalization	13,436	12,933
Debt to Capitalization	28%	27%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

As at	March 31, 2012	December 31, 2011
Debt	3,735	3,527
Net Earnings	1,857	1,478
Add (deduct):		
Finance costs	443	447
Interest income	(121)	(124)
Income tax expense	857	729
Depreciation, depletion and amortization	1,389	1,295
Unrealized (gain) loss on risk management	(512)	(180)
Foreign exchange (gain) loss, net	33	26
(Gain) loss on divestiture of assets	(107)	(107)
Other (income) loss, net	-	4
Adjusted EBITDA *	3,839	3,568
Debt to Adjusted EBITDA	1.0x	1.0x

* Calculated on a trailing twelve-month basis.

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

As at March 31, 2012, Cenovus is in compliance with all of the terms of its debt agreements.

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19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings, long-term debt and obligations for stock-based compensation carried at fair value. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows.

A) Fair Value of Financial Assets and Liabilities

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

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable, partner loans and long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

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

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on prices sourced from market data. As at March 31, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was \$3,465 million and the fair value was \$4,207 million (December 31, 2011 carrying value – \$3,527, fair value – \$4,316).

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at	March 31, 2012	December 31, 2011
Risk Management Assets		
Current asset	258	232
Long-term asset	112	52
	<u>370</u>	<u>284</u>
Risk Management Liabilities		
Current liability	87	54
Long-term liability	6	14
	<u>93</u>	<u>68</u>
Net Risk Management Asset (Liability) ¹	<u>277</u>	<u>216</u>

1. Under the terms of the Arrangement, the risk management positions as at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with Encana with the same terms and conditions as between Encana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties. Of the \$277 million net risk management asset balance as at March 31, 2012, a liability of \$1 million relates to the contract with Encana (December 31, 2011 – liability of \$3 million).

Summary of Unrealized Risk Management Positions

As at	March 31, 2012			December 31, 2011		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	82	92	(10)	22	65	(43)
Natural Gas	279	1	278	247	3	244
Power	9	-	9	15	-	15
Total Fair Value	<u>370</u>	<u>93</u>	<u>277</u>	<u>284</u>	<u>68</u>	<u>216</u>

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Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	March 31, 2012	December 31, 2011
Prices actively quoted	194	226
Prices sourced from observable data or market corroboration	83	(10)
Total Fair Value	277	216

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

Net Fair Value of Commodity Price Positions as at March 31, 2012

As at March 31, 2012	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,800 bbls/d	2012	US\$98.72/bbl	(40)
WTI NYMEX Fixed Price	24,500 bbls/d	2012	\$99.47/bbl	(36)
WTI NYMEX Fixed Price	10,000 bbls/d	2013	US\$102.62/bbl	(3)
WTI NYMEX Fixed Price	10,000 bbls/d	2013	\$103.26/bbl	(5)
Other Fixed Price Contracts ¹		2012-2013		75
Other Financial Positions ²				(1)
Crude Oil Fair Value Position				(10)
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US\$5.96/Mcf	124
AECO Fixed Price ¹	127 MMcf/d	2012	\$4.50/Mcf	84
NYMEX Fixed Price	166 MMcf/d	2013	US\$4.64/Mcf	71
Other Fixed Price Contracts ¹		2012-2013		(1)
Natural Gas Fair Value Position				278
Power Purchase Contracts				
Power Fair Value Position				9

1. Cenovus has entered into fixed price swaps to protect against widening price differentials between production areas in Canada, various sales points and quality differentials.

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

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

For the period ended March 31,	Three Months Ended	
	2012	2011
REALIZED GAIN (LOSS) ¹		
Crude Oil	(26)	(34)
Natural Gas	60	52
Refining	(5)	(5)
Power	-	1
	29	14
UNREALIZED GAIN (LOSS) ²		
Crude Oil	30	(260)
Natural Gas	36	(33)
Refining	3	3
Power	(5)	22
	64	(268)
Gain (Loss) on Risk Management	93	(254)

1. Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.

2. Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended March 31, 2012

Reconciliation of Unrealized Risk Management Positions from January 1 to March 31,

	2012		2011
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	216		
Change in fair value of contracts in place at beginning of year and contracts entered into during the period	93	93	(254)
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	(3)	-	-
Fair value of contracts realized during the period	(29)	(29)	(14)
Fair Value of Contracts, End of Period	<u>277</u>	<u>64</u>	<u>(268)</u>

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting earnings before income tax on open risk management positions as at March 31, 2012 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US\$10 per bbl applied to WTI hedges	(237)	237
Crude oil differential price	± US\$5 per bbl applied to differential hedges tied to production	85	(85)
Natural gas commodity price	± \$1 per mcf applied to NYMEX and AECO natural gas hedges	(134)	134
Natural gas basis price	± \$0.10 per mcf natural gas basis hedges	3	(3)
Power commodity price	± \$25 per MWhr applied to power hedge	19	(19)

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

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

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. To help protect against widening crude oil price differentials, Cenovus has entered into a limited number of swaps and futures to manage the price differentials.

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

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

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with counterparties, most of which have investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated
For the period ended March 31, 2012

and are subject to normal industry credit risks. As at March 31, 2012, 94 percent (December 31, 2011 – over 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

As at March 31, 2012, Cenovus had two counterparties whose net settlement position individually account for more than 10 percent (December 31, 2011 – two counterparties) of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value. The current concentration of this credit risk resides with A rated or higher counterparties. Cenovus's exposure to its counterparties is acceptable and within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 18, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. As at March 31, 2012, Cenovus had \$2,730 million available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for \$1,500 million and a U.S. debt shelf prospectus for US\$1,500 million, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

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

	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,510	-	-	-	2,510
Risk Management Liabilities	87	6	-	-	93
Short-Term Borrowings ¹	270	-	-	-	270
Long-Term Debt ¹	204	1,190	337	5,092	6,823
Partnership Contribution Payable ¹	488	977	977	-	2,442
Other ¹	4	7	3	5	19

1. Principal and interest, including current portion.

Foreign Exchange Risk

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

As disclosed in Note 5, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. As at March 31, 2012, Cenovus had US\$3,500 million in U.S. dollar debt issued from Canada (US\$3,500 million as at December 31, 2011) and US\$2,067 million related to the U.S. dollar Partnership Contribution Receivable (US\$2,157 million as at December 31, 2011). A \$0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a \$14 million change in foreign exchange (gain) loss as at March 31, 2012 (December 31, 2011 – \$13 million).

Interest Rate Risk

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

As at March 31, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to \$2 million (December 31, 2011 – \$nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

20. COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

SUPPLEMENTAL INFORMATION *(unaudited)*
Financial Statistics
(\$ millions, except per share amounts)

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	4,686	16,185	4,480	3,989	4,085	3,631
Less: Royalties	122	489	151	131	76	131
Revenues	4,564	15,696	4,329	3,858	4,009	3,500
Operating Cash Flow						
Crude Oil and Natural Gas Liquids						
Foster Creek and Christina Lake	290	905	274	213	245	173
Pelican Lake	127	305	69	83	76	77
Conventional	267	881	246	209	218	208
Natural Gas	132	777	188	200	197	192
Other Upstream Operations	2	13	4	2	3	4
	818	2,881	781	707	739	654
Refining and Marketing	267	981	238	238	325	180
Operating Cash Flow ⁽¹⁾	1,085	3,862	1,019	945	1,064	834
Cash Flow Information						
Cash from Operating Activities	665	3,273	952	921	769	631
Deduct (Add back):						
Net change in other assets and liabilities	(32)	(82)	(20)	(17)	(16)	(29)
Net change in non-cash working capital	(207)	79	121	145	(154)	(33)
Cash Flow ⁽²⁾	904	3,276	851	793	939	693
Per share - Basic	1.20	4.34	1.13	1.05	1.25	0.92
- Diluted	1.19	4.32	1.12	1.05	1.24	0.91
Operating Earnings ⁽³⁾	340	1,239	332	303	395	209
Per share - Diluted	0.45	1.64	0.44	0.40	0.52	0.28
Net Earnings	426	1,478	266	510	655	47
Per share - Basic	0.56	1.96	0.35	0.68	0.87	0.06
- Diluted	0.56	1.95	0.35	0.67	0.86	0.06
Effective Tax Rates using						
Net Earnings	28.3%	33.0%				
Operating Earnings, excluding divestitures	30.9%	34.5%				
Canadian Statutory Rate	25.2%	26.7%				
U.S. Statutory Rate	37.5%	37.5%				
Foreign Exchange Rates (US\$ per C\$1)						
Average	0.999	1.012	0.978	1.020	1.033	1.015
Period end	1.001	0.983	0.983	0.963	1.037	1.029

⁽¹⁾ Operating Cash Flow is a non-GAAP measure defined as revenue less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities.

⁽²⁾ Cash Flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

⁽³⁾ Operating Earnings is a non-GAAP measure defined as Net Earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management accounting gains (losses) on derivative instruments, 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, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)

Debt to Capitalization ^{(4), (5)}	28%	27%
Debt to Adjusted EBITDA ^{(5), (6)}	1.0x	1.0x
Return on Capital Employed ⁽⁷⁾	16%	13%
Return on Common Equity ⁽⁸⁾	21%	17%

⁽⁴⁾ Capitalization is a non-GAAP measure defined as Debt plus Shareholders' Equity.

⁽⁵⁾ Debt includes the Company's short-term borrowings plus long-term debt, including the current portion of long-term debt.

⁽⁶⁾ Adjusted EBITDA is a non-GAAP measure defined as adjusted earnings before interest income, finance costs, income taxes, DD&A, exploration expense, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), calculated on a trailing twelve-month basis.

⁽⁷⁾ Calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average Shareholders' Equity plus average Debt.

⁽⁸⁾ Calculated, on a trailing twelve-month basis, as net earnings divided by average Shareholders' Equity.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Common Share Information

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)						
Period end	755.6	754.5	754.5	754.3	754.1	753.9
Average - Basic	755.1	754.0	754.4	754.3	754.1	753.2
Average - Diluted	759.5	757.7	757.1	757.8	758.0	758.1
Price Range (\$ per share)						
TSX - C\$						
High	39.64	38.98	37.11	38.38	38.98	38.90
Low	33.24	28.85	28.85	29.87	31.73	31.15
Close	35.90	33.83	33.83	32.27	36.40	38.30
NYSE - US\$						
High	39.81	40.73	37.35	40.61	40.73	40.06
Low	32.45	27.15	27.15	29.02	32.48	31.11
Close	35.94	33.20	33.20	30.71	37.66	39.38
Dividends Paid (\$ per share)	\$ 0.22	\$ 0.80	\$ 0.20	\$ 0.20	\$ 0.20	\$ 0.20
Share Volume Traded (millions)	177.4	873.7	213.3	239.8	215.9	204.7

Net Capital Investment (\$ millions)

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment						
Oil Sands						
Foster Creek	159	429	139	110	77	103
Christina Lake	127	472	126	117	121	108
Total	286	901	265	227	198	211
Pelican Lake	139	317	132	70	31	84
Other Oil Sands	211	197	68	9	11	109
Conventional	636	1,415	465	306	240	404
Refining and Marketing	231	788	330	193	89	176
Corporate	(2)	393	73	101	117	102
Capital Investment	35	127	35	31	30	31
Acquisitions	8	71	49	1	2	19
Divestitures	(66)	(173)	(164)	-	(5)	(4)
Net Acquisition and Divestiture Activity	(58)	(102)	(115)	1	(3)	15
Net Capital Investment	842	2,621	788	632	473	728

Operating Statistics - Before Royalties

Upstream Production Volumes

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)						
Oil Sands - Heavy						
Foster Creek	57,214	54,868	55,045	56,322	50,373	57,744
Christina Lake	24,733	11,665	19,531	10,067	7,880	9,084
Total	81,947	66,533	74,576	66,389	58,253	66,828
Pelican Lake	20,730	20,424	20,558	20,363	19,427	21,360
	102,677	86,957	95,134	86,752	77,680	88,188
Conventional Liquids						
Heavy Oil	16,624	15,657	15,512	15,305	15,378	16,447
Light and Medium Oil	36,411	30,524	32,530	30,399	27,617	31,539
Natural Gas Liquids ⁽¹⁾	1,138	1,101	1,097	1,040	1,087	1,181
Total Crude Oil and Natural Gas Liquids	156,850	134,239	144,273	133,496	121,762	137,355
Natural Gas (MMcf/d)						
Oil Sands	41	37	38	39	37	32
Conventional ⁽²⁾	595	619	622	617	617	620
Total Natural Gas	636	656	660	656	654	652

⁽¹⁾ Natural gas liquids include condensate volumes.

⁽²⁾ In Q1 2012, a non-core natural gas property was divested, decreasing Q1 production approximately 2%.

Average Royalty Rates

(excluding impact of realized gain (loss) on risk management)

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands						
Foster Creek ⁽³⁾	13.9%	16.8%	21.7%	20.6%	3.3%	21.2%
Christina Lake	7.0%	5.2%	4.7%	5.7%	6.3%	4.8%
Pelican Lake	4.5%	11.5%	9.1%	12.7%	9.7%	13.9%
Conventional						
Weyburn	23.3%	24.1%	24.8%	23.9%	23.6%	24.3%
Other	8.3%	8.3%	8.1%	9.0%	8.5%	7.6%
Natural Gas Liquids	1.7%	1.7%	1.8%	1.4%	2.3%	1.3%
Natural Gas	2.5%	1.7%	1.9%	1.5%	1.2%	2.3%

⁽³⁾ Foster Creek royalty rate was significantly lower in Q2 2011 as a result of the Alberta Department of Energy approving the expansion phases F, G and H capital investment to be included as part of the existing royalty calculation.

SUPPLEMENTAL INFORMATION (unaudited)

Operating Statistics - Before Royalties (continued)

Refining	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations ⁽¹⁾						
Crude oil capacity (Mbbbls/d)	452	452	452	452	452	452
Crude oil runs (Mbbbls/d)	445	401	424	413	406	362
Crude utilization	98%	89%	94%	91%	90%	80%
Refined products (Mbbbls/d)	465	419	442	426	422	383

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

Selected Average Benchmark Prices	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices (US\$/bbl)						
West Texas Intermediate ("WTI")	103.03	95.11	94.06	89.54	102.34	94.60
Western Canadian Select ("WCS")	81.61	77.96	83.58	71.92	84.70	71.74
Differential - WTI-WCS	21.42	17.15	10.48	17.62	17.64	22.86
Condensate - (C5 @ Edmonton)	110.16	105.34	108.74	101.48	112.33	98.90
Differential - WTI-Condensate (premium)/discount	(7.13)	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)
Refining Margins 3-2-1 Crack Spreads ⁽²⁾ (US\$/bbl)						
Chicago	19.00	24.55	19.23	33.35	29.00	16.62
Midwest Combined (Group 3)	21.50	25.26	20.75	34.04	27.19	19.04
Natural Gas Prices						
AECO (\$/GJ)	2.39	3.48	3.29	3.53	3.54	3.58
NYMEX (US\$/MMBtu)	2.74	4.04	3.55	4.19	4.31	4.11
Differential - NYMEX/AECO (US\$/MMBtu)	0.21	0.31	0.17	0.34	0.42	0.29

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

Per-unit Results

(\$, excluding impact of realized gain (loss) on risk management)

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek (\$/bbl) ⁽¹⁾						
Price	70.71	67.38	75.96	62.68	72.23	59.50
Royalties	9.54	10.82	15.81	12.38	2.30	11.92
Transportation and blending	2.38	3.04	3.20	2.73	2.82	3.41
Operating	12.85	11.34	11.31	11.11	11.57	11.40
Netback	45.94	42.18	45.64	36.46	55.54	32.77
Heavy Oil - Christina Lake (\$/bbl) ⁽¹⁾						
Price	52.58	61.86	66.69	54.52	67.06	54.67
Royalties	3.37	3.03	2.97	2.87	3.98	2.44
Transportation and blending	4.51	3.53	2.98	4.54	3.51	3.69
Operating	15.33	20.20	17.96	23.01	23.41	19.09
Netback	29.37	35.10	42.78	24.10	36.16	29.45
Heavy Oil - Pelican Lake (\$/bbl) ⁽¹⁾						
Price	78.50	73.07	88.67	66.76	78.26	64.66
Royalties	3.37	7.91	6.98	8.23	7.40	8.63
Transportation and blending	2.88	4.14	12.19	1.87	2.02	2.44
Operating	16.05	14.86	16.49	14.31	13.40	15.35
Netback	56.20	46.16	53.01	42.35	55.44	38.24
Heavy Oil - Oil Sands (\$/bbl) ⁽¹⁾						
Price	68.36	67.99	76.39	62.93	73.02	60.35
Royalties	6.66	9.17	11.72	10.46	3.65	10.08
Transportation and blending	2.99	3.36	4.75	2.68	2.71	3.18
Operating	14.18	13.27	13.54	13.02	13.27	13.23
Netback	44.53	42.19	46.38	36.77	53.39	33.86
Heavy Oil - Conventional (\$/bbl) ⁽¹⁾						
Price	80.64	74.17	81.49	67.96	78.47	69.17
Royalties	13.06	10.75	11.85	11.33	10.98	9.04
Transportation and blending	1.81	1.27	1.34	1.80	0.91	1.05
Operating	17.57	13.77	16.34	12.40	13.66	12.78
Production and mineral taxes	0.14	0.32	0.34	0.17	0.22	0.51
Netback	48.06	48.06	51.62	42.26	52.70	45.79
Total Heavy Oil (\$/bbl) ⁽¹⁾						
Price	70.08	68.98	77.16	63.69	73.98	61.80
Royalties	7.56	9.42	11.74	10.59	4.93	9.91
Transportation and blending	2.82	3.02	4.23	2.55	2.40	2.83
Operating	14.65	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	0.02	0.05	0.05	0.03	0.04	0.08
Netback	45.03	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil (\$/bbl)						
Price	88.45	85.40	90.90	79.57	94.30	77.39
Royalties	9.94	11.54	12.12	10.74	12.82	10.58
Transportation and blending	2.83	2.00	1.99	1.90	2.22	1.92
Operating	15.36	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	2.57	2.27	2.63	2.40	2.77	1.32
Netback	57.75	55.21	59.04	50.16	63.53	48.71

⁽¹⁾ The 2012 YTD heavy oil price and transportation and blending costs exclude the costs of condensate purchases which is blended with the heavy oil as follows: Foster Creek - \$48.70/bbl; Christina Lake - \$53.90/bbl; Pelican Lake - \$19.39/bbl; Heavy Oil - Oil Sands - \$42.99/bbl; Heavy Oil - Conventional - \$15.82/bbl and Total Heavy Oil - \$39.19/bbl.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

(\$, excluding impact of realized gain (loss) on risk management)

	2012		2011			
	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil (\$/bbl)						
Price	74.22	72.80	80.49	67.37	78.71	65.32
Royalties	8.10	9.92	11.83	10.62	6.77	10.06
Transportation and blending	2.83	2.78	3.69	2.40	2.35	2.63
Operating	14.81	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	0.59	0.57	0.67	0.58	0.67	0.36
Netback	47.89	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids (\$/bbl)						
Price	83.36	76.84	82.26	74.38	80.32	70.67
Royalties	1.45	1.34	1.51	1.06	1.87	0.93
Netback	81.91	75.50	80.75	73.32	78.45	69.74
Total Liquids (\$/bbl)						
Price	74.28	72.84	80.50	67.43	78.72	65.37
Royalties	8.05	9.84	11.75	10.55	6.72	9.98
Transportation and blending	2.81	2.76	3.66	2.38	2.33	2.60
Operating	14.71	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	0.59	0.56	0.67	0.57	0.67	0.36
Netback	48.12	46.21	50.29	40.77	55.87	39.00
Total Natural Gas (\$/Mcf)						
Price	2.50	3.65	3.35	3.72	3.71	3.82
Royalties	0.06	0.06	0.06	0.05	0.04	0.08
Transportation and blending	0.13	0.15	0.14	0.15	0.14	0.17
Operating	1.08	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	0.02	0.04	0.01	0.03	0.05	0.06
Netback	1.21	2.30	1.92	2.50	2.50	2.32
Total (\$/BOE)⁽²⁾						
Price	50.84	49.75	53.48	46.97	51.81	46.83
Royalties	5.00	5.55	6.65	5.91	3.64	5.85
Transportation and blending	2.00	1.91	2.39	1.70	1.61	1.92
Operating ⁽¹⁾	11.46	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	0.40	0.41	0.40	0.39	0.49	0.36
Netback	31.98	31.53	32.95	29.09	36.38	28.02

⁽¹⁾ 2012 YTD operating costs include costs related to long-term incentives of \$0.42/BOE (2011 - \$1.11/BOE).

Impact of realized gain (loss) on risk management

Liquids (\$/bbl)	(1.67)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas (\$/Mcf)	1.03	0.87	1.10	0.76	0.74	0.89
Total (\$/BOE)⁽²⁾	1.44	0.86	1.22	2.49	(1.25)	0.83

⁽²⁾ Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

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) Readers should also refer to “Risk Management” in each of our annual MD&A for the year ended December 31, 2011 and our current MD&A and to the risk factors described in other documents we file from time to time with securities regulatory authorities, available at www.sedar.com, www.sec.gov and www.cenovus.com.

ABBREVIATIONS

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

Oil and Natural Gas Liquids

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

Natural Gas

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

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as cash flow, operating cash flow, free cash flow, operating earnings, adjusted EBITDA, debt and capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the 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.

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