

Third Quarter

2012

cenovus
ENERGY

Cenovus oil sands production climbs 44% in third quarter Cash flow rises 41% on strong refining results, increased oil production

- Average oil sands production exceeded 95,000 barrels per day (bbls/d) net to Cenovus, a 44% increase compared with the same period a year earlier.
- Cash flow surpassed \$1.1 billion or \$1.47 per share diluted in the third quarter, 41% higher than the same period last year.
- Operating cash flow from refining more than doubled to \$530 million compared with the third quarter of 2011, primarily due to increased throughput, higher yields and strong refining margins.
- Christina Lake production grew more than threefold in the third quarter compared with 2011. Production averaged more than 32,000 bbls/d net, reaching a single-day high of 43,500 bbls/d net. The increase was due to strong phase C well performance and the start-up of phase D in late July.
- Foster Creek production increased 12% compared with the third quarter of 2011, averaging above current design capacity through the quarter.
- Third quarter production at Pelican Lake increased 16% compared with the same quarter of 2011, averaging more than 23,500 bbls/d.
- In September, Cenovus was named to the Dow Jones Sustainability World Index for the first time and was recently named to the Carbon Disclosure Leadership Index for the third year in a row.

“Cenovus continues to deliver predictable, reliable performance and is on track for another great year, both operationally and financially,” said Brian Ferguson, Cenovus President & Chief Executive Officer. “Our integrated strategy is clearly paying off. Increased oil sands production combined with strong margins at our refining business contributed to record cash flow and solid operating earnings in the third quarter.”

Financial & Production Summary

(for the period ended September 30) (\$ millions, except per share amounts)	2012 Q3	2011 Q3	% change
Cash flow ¹	1,117	793	41
Per share diluted	1.47	1.05	
Operating earnings ¹	432	303	43
Per share diluted	0.57	0.40	
Net earnings	289	510	-43
Per share diluted	0.38	0.67	
Capital investment ²	830	631	32
Production (before royalties)			
Foster Creek (bbls/d)	63,245	56,322	12
Christina Lake (bbls/d)	32,380	10,067	222
Total Foster Creek & Christina Lake (bbls/d)	95,625	66,389	44
Pelican Lake (bbls/d)	23,539	20,363	16
Other conventional oil ³ (bbls/d)	52,186	46,744	12
Total oil production (bbls/d)	171,350	133,496	28
Natural gas (MMcf/d)	577	656	-12

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, excluding acquisitions and divestitures.

³ Includes natural gas liquids (NGLs) production.

Calgary, Alberta (October 25, 2012) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered strong third quarter performance led by significant growth in oil sands production and excellent results from its refining operations. As planned, the company increased capital spending compared with the same period a year ago as it continued to expand operations at its oil sands assets and conventional oil properties in Alberta and Saskatchewan.

Combined output from Foster Creek and Christina Lake reached more than 95,000 bbls/d net to Cenovus in the third quarter, a 44% increase from the same period last year. Production at Christina Lake averaged more than 32,000 bbls/d net, a more than threefold increase from the third quarter of 2011, driven by strong performance from phase C and the ramp-up of production at phase D. Full capacity was reached at phase C in the first quarter, while phase D saw first oil production in late July, approximately three months ahead of schedule. During the quarter, Christina Lake also achieved a single-day production high of more than 87,000 bbls/d gross. Once phase D is fully ramped up, production capacity at Christina Lake is expected to reach 98,000 bbls/d gross. With the addition of another four planned phases, Cenovus believes Christina Lake has the potential to produce 288,000 bbls/d gross, increasing to as much as 300,000 bbls/d with optimization.

Production at Foster Creek grew 12%, compared with the third quarter of 2011, to more than 63,000 bbls/d net, mainly due to improved well performance and plant optimization. Throughout the quarter, production at Foster Creek consistently exceeded the project's original design capacity by approximately 5%, averaging more than 126,000 bbls/d gross. There are five phases currently producing at Foster Creek, with three more under construction. A public consultation process is under way for an additional expansion phase. Ultimately, Cenovus expects Foster Creek will have the capacity to produce 295,000 bbls/d gross and as much as 310,000 bbls/d with optimization.

"We have a great resource base that includes some of the best in-situ oil sands reservoirs in the industry," said John Brannan, Cenovus Executive Vice-President & Chief Operating Officer. "Our teams have done a great job starting up new production in these reservoirs safely, on schedule and within budget. Thanks to the strong performance of both our oil sands and conventional businesses, our oil growth is ahead of plan."

Including expansion phases already under construction and those with regulatory approval, Cenovus is on track to add approximately 400,000 bbls/d of additional gross oil sands production (approximately 200,000 bbls/d net) over the next five years. The company expects to bring on new phases at Foster Creek and Christina Lake at a cost of \$22,000 to \$25,000 per flowing barrel. Cenovus is also focused on maintaining industry-leading supply costs. At Foster Creek and Christina Lake, supply costs are approximately \$35 to \$45 per barrel. Supply costs are calculated as the long-term average West Texas Intermediate (WTI) oil price required to achieve a 9% after-tax return after all capital, operating and maintenance costs are considered.

Solid financial performance

Total third quarter cash flow surpassed \$1.1 billion, a 41% increase from the same period a year earlier. The increase was due to higher oil production and improved operating cash flow from Cenovus's refining business. Third quarter operating cash flow from refining more than doubled to \$530 million, compared with the same period in 2011, driven by strong refining margins and increased refinery throughput. Cenovus's third quarter operating earnings were \$432 million, a 43% increase over 2011.

During the third quarter, Cenovus took advantage of attractive long-term interest rates to complete a public offering in the United States of US\$1.25 billion of senior unsecured notes, consisting of US\$500 million of 10-year notes with a coupon rate of 3% due August 15, 2022 and US\$750 million of 30-year notes with a coupon rate of 4.45% due September 15, 2042. Combined with its existing credit facilities, the debt offering provides Cenovus with considerable additional financial flexibility as it continues to execute its growth plan.

Investing in oil growth

In the third quarter Cenovus invested \$830 million in capital projects, a 32% increase from the same period a year earlier and in line with full-year guidance. Third quarter capital investment at its producing oil sands properties increased by 52% to \$346 million. This included spending for construction, pre-construction and design engineering work for the next three phases at Foster Creek and facility construction, site preparation work and design engineering for the next three phases at Christina Lake.

Capital investment at Pelican Lake was \$128 million in the third quarter, an 83% increase from the same period in 2011. The company plans to drill about 1,000 additional production and injection wells over the next five to seven years to expand the polymer flood. Production at Pelican Lake is expected to reach 55,000 bbls/d.

At its other conventional oil properties, Cenovus increased capital investment by 33% to \$224 million during the quarter, when compared with 2011. That included investment in tight oil drilling programs in Alberta and drilling, completion and facilities work in Saskatchewan. The company's goal is to increase production from its conventional oil properties, excluding Pelican Lake, from just over 52,000 bbls/d today to between 65,000 and 75,000 bbls/d by the end of 2016.

As part of its integrated strategy, Cenovus's non-oil producing assets continue to provide significant ongoing financial support for the company's oil growth plans. In the first nine months of the year, Cenovus's natural gas and refining operations combined, generated more than \$1.4 billion of operating cash flow in excess of capital invested.

Strong potential at Telephone Lake

Cenovus's 100%-owned Telephone Lake asset has shown tremendous potential since the company first began drilling test wells at the property. More recent drilling has only served to increase Cenovus's confidence that the proposed oil sands project in northern Alberta may become another cornerstone asset, similar to Foster Creek or Christina Lake.

"Last year, we made a joint regulatory application for a 90,000 barrels per day project at Telephone Lake, but we believe that is just the beginning," Ferguson said. "With future expansions, we anticipate Telephone Lake has the potential to support a project with production capacity of more than 300,000 barrels per day."

Cenovus has recently completed a number of minor acquisitions to add complementary oil sands acreage to its Telephone Lake property. Late last year, the company purchased several small parcels of land located within the company's broader Telephone Lake acreage to consolidate the property. Earlier this month, Cenovus also acquired the assets of Oilsands Quest, a bankrupt oil sands exploration company, for \$10 million. The assets include three oil sands leases, covering approximately 59,000 hectares in Alberta and Saskatchewan, that are adjacent to Telephone Lake. Cenovus is assessing the potential incremental benefit of these acquisitions.

Recognition for corporate responsibility

In September, Cenovus was named to the Dow Jones Sustainability World Index for the first time. Cenovus is the only Canadian integrated oil and gas company to make the World Index in 2012 and one of just 11 Canadian corporations overall. The Dow Jones Sustainability Indexes (DJSI) recognize companies around the world for leadership in corporate responsibility. Cenovus was also named to the DJSI North America Index for the third year in a row. As well, the company was recently named to the Carbon Disclosure Leadership Index for the third consecutive year for exceptional disclosure of greenhouse gas emissions.

Guidance updated

Cenovus has updated its 2012 full-year guidance to reflect actual numbers for the first nine months of the year and the company's estimates for the fourth quarter. Of note, Cenovus has increased its midpoint guidance for expected full-year cash flow by 11%. Total 2012 cash flow is now expected to be 22% higher than last year. Updated guidance can be found at www.cenovus.com under "Invest in us".

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

(Before royalties) (Mbbbls/d)	Daily Production ¹									
	2012				2011				2010	
	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands										
Foster Creek	57	63	52	57	55	55	56	50	58	51
Christina Lake	29	32	29	25	12	20	10	8	9	8
Oil sands total	86	96	80	82	67	75	66	58	67	59
Conventional oil										
Pelican Lake	22	24	22	21	20	21	20	19	21	23
Weyburn	16	16	16	17	16	17	16	15	17	17
Other oil ²	37	36	36	38	31	32	31	29	32	31
Conventional total	75	76	75	75	68	70	67	64	71	70
Total oil	161	171	156	157	134	144	133	122	137	129

¹ Totals may not add due to rounding.

² Includes NGLs production.

Oil sands

Foster Creek and Christina Lake

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

Production

- Production at Foster Creek and Christina Lake increased 44% in the third quarter from the same period a year earlier.
- Christina Lake production averaged 32,380 bbls/d in the quarter, a more than three-fold increase from the same period a year earlier. The substantial increase is due to the industry-leading start-up and continued strong performance of phase C since late last year and the commissioning of phase D in July. Phase C reached full capacity during the first quarter while phase D continues to ramp up.
- Cenovus continues to sell most of its oil from Christina Lake as Christina Dilbit Blend (CDB). This blend is gaining acceptance from a wider base of refining customers, including the company's jointly owned Wood River Refinery. As a result, the pricing discount for CDB has narrowed, in line with expectations.
- Foster Creek production averaged 63,245 bbls/d in the quarter, a 12% increase compared with 2011, mainly due to improved well performance and plant optimization.
- 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). Ten additional wells using this technology are expected to have steam stimulation completed and be online before the end of 2012. Christina Lake is also beginning to see positive results from four wells using this technology, currently producing about 1,100 bbls/d.

Expansions

- Phase D at Christina Lake achieved first production in late July and is expected to reach its full design capacity of 40,000 bbls/d in the second quarter of 2013.
- Overall construction of Christina Lake phase E is approximately 60% complete, while the central plant is approximately 81% complete. First production is anticipated in the fourth quarter of 2013. Initial site preparation and the purchase of equipment continue at phase F and engineering and design work are underway for phase G.
- At Foster Creek, overall construction of the combined F, G and H expansion is approximately 33% complete, while the phase F plant is more than 60% complete. Initial production from phase F is expected in 2014. Facility construction, offsite fabrication and equipment purchasing are underway at phase G and engineering is underway for phase H.

Operating costs and royalties

- Operating costs at Christina Lake were \$13.59/bbl in the third quarter, a 41% decrease from \$23.01/bbl in the same period a year earlier due to the significant increase in production. Operating costs at Christina Lake are expected to be lower than initially anticipated and the company has adjusted its full-year guidance to \$12.70/bbl. Non-fuel operating costs at Christina Lake were \$11.03/bbl in the quarter, a 43% decrease from \$19.44/bbl in the third quarter of 2011.
- Operating costs at Foster Creek averaged \$11.50/bbl in the third quarter, a 4% increase from \$11.11/bbl in the same period last year. The increase is primarily due to higher staffing levels in preparation for the phase F expansion and increased well workovers. The company expects operating costs at Foster Creek to average \$12.05/bbl for the full year, which is within the company's original guidance range. Non-fuel operating costs at Foster Creek were \$9.76/bbl in the third quarter compared with \$8.86/bbl in the same period a year earlier, a 10% increase.
- Christina Lake's average royalty rate in the quarter was 5.3%, compared with an average royalty rate of 5.7% for the same period a year earlier. The rate drop was primarily due to a decrease in the average WTI price used by the Alberta government to calculate royalties.

- Foster Creek's average royalty rate was 19.1% in the third quarter of 2012, a decline from 20.6% in the same period in 2011. Royalties were lower due to higher capital investment.
- Royalty calculations for Cenovus's oil sands projects differ between properties. Pre-payout royalties at Christina Lake are a function of the monthly Canadian dollar WTI benchmark price and volumes. Foster Creek is a post-payout project for royalty purposes so its royalties are impacted by volumes, an estimated annualized price, adjusted quarterly, and allowable operating and capital costs.

Steam to oil ratios

- Cenovus continues to achieve some of the best SORs in the industry with a third quarter average ratio of about 1.9 at Christina Lake and about 2.1 at Foster Creek for a combined SOR of about 2.
- An SOR of 2 means approximately two barrels of steam are needed for every barrel of oil produced. A lower SOR requires less steam, which means less natural gas is used. This 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.

- On September 25, Cenovus broke ground on its Narrows Lake project, which is jointly owned with ConocoPhillips. Narrows Lake is expected to have gross production capacity of 130,000 bbls/d and be developed in three phases. Project sanctioning for the first phase is expected from Cenovus and ConocoPhillips by the end of this year.
- The Narrows Lake regulatory approval included the option to use a combination of SAGD and solvent aided process (SAP) for oil production. Based on test results at other locations, Cenovus expects SAP to improve the SOR and oil production rate by as much as 30% compared to SAGD alone. Cenovus also expects SAP to increase total oil recovery by as much as 15%.
- The joint regulatory application and environmental impact assessment for a commercial SAGD project at Cenovus's wholly owned Grand Rapids asset in the Greater Pelican Region is being reviewed by the regulators. The company believes Grand Rapids has the potential to reach production capacity of 180,000 bbls/d.
- Cenovus is continuing to develop a pilot project in the Grand Rapids area. Construction for the installation of a third mobile steam generator is progressing and steam injection has started on the second well pair.
- The revised joint regulatory application and environmental impact assessment for the 100%-owned Telephone Lake project in the Borealis Region is also being reviewed by the regulators. The application updates the expected production capacity for the initial phase at Telephone Lake to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007. With future expansion phases, Cenovus believes Telephone Lake has the potential to support production capacity of more than 300,000 bbls/d.

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 a waterflood to enhance production from the reservoir. Based on reservoir performance of the polymer flood, the company has initiated a multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d.

- Production averaged more than 23,500 bbls/d in the third quarter, a 16% increase from the same period in 2011. Cenovus continues to be encouraged by results from its infill drilling program to expand the polymer flood. Production increases continue to be partially offset by reduced operating pressures related to temporary well shut-ins required to complete infill drilling between existing wells. The company expects Pelican Lake production for the full year to be at the lower end of its original guidance range.
- Cenovus plans to continue expanding Pelican Lake by drilling approximately 1,000 additional production and injection wells over the next five to seven years to increase the polymer flood. The company 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 \$17.47/bbl in the quarter, a 22% increase from \$14.31/bbl in the third quarter of 2011 due to higher workovers, repairs and maintenance, additional staffing and increased polymer costs associated with the expansion of the polymer flood. Cenovus has adjusted its full-year guidance for operating costs at Pelican Lake to \$16.65/bbl, slightly above the top end of its original guidance range.
- Pelican Lake's average royalty rate was 6.6% in the third quarter of 2012 compared with 12.7% in the same period of 2011. The reduction was primarily due to increased capital investment to expand the polymer flood.

Other conventional oil

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 Bakken and Lower Shaunavon tight oil assets in southern Saskatchewan, and established properties in southern Alberta. By the end of 2016, Cenovus is targeting oil production from these properties between 65,000 bbls/d and 75,000 bbls/d.

- Third quarter production from the company's conventional oil assets in Alberta increased 10% over the same period in 2011 to nearly 30,000 bbls/d, primarily due to successful drilling programs and effective management of natural declines.
- The Weyburn operation produced about 16,000 bbls/d net in the third quarter. This is a 3% increase compared with the same period a year earlier, when wet weather affected production.
- Lower Shaunavon production averaged approximately 4,550 bbls/d in the third quarter, a 77% increase compared with the same period a year earlier, due to additional development drilling. Cenovus has 118 horizontal wells producing in the Lower Shaunavon.
- In the third quarter of 2012, Cenovus completed construction of the Lower Shaunavon battery.
- The company's Bakken operation had average oil production of more than 1,700 bbls/d in the quarter, including royalty interest volumes, an 18% increase compared with the same period a year earlier, due to additional drilling. Cenovus had 27 producing wells in the Bakken area at the end of the third quarter.
- Operating costs for Cenovus's conventional oil operations, excluding Pelican Lake, increased 19% to \$16.33/bbl in the third quarter compared with the same period a year earlier. This was due to higher costs for repairs and maintenance, electricity, trucking and waste handling and labour.

Natural Gas

(Before royalties) (MMcf/d)	Daily Production										
	2012					2011					2010
	YTD	Q3	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year	
Natural Gas ¹	602	577	596	636	656	660	656	654	652	737	

¹ Reflects production from the sale of non-core assets in the third quarter of 2010 and the first quarter of 2012.

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 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 third quarter was approximately 577 million cubic feet per day (MMcf/d), a 12% decline from the same period in the previous year. The decrease is mainly due to expected natural declines and to the divestiture of a non-core property early in the first quarter of 2012.
- Cenovus's average realized sales price for natural gas, including hedges, was \$3.54 per thousand cubic feet (Mcf) in the quarter compared with \$4.48 per Mcf in the same period a year earlier.
- As a result of the efficient, low-cost nature of its natural gas assets, Cenovus generated third quarter natural gas operating cash flow of \$118 million in excess of capital invested in those properties.
- Cenovus anticipates managing an annual decline rate of 10% to 15% for its natural gas production, targeting a long-term production level of between 400 MMcf/d and 500 MMcf/d to match Cenovus's future anticipated internal consumption 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, Phillips 66.

- The two refineries produced approximately 463,000 bbls/d gross of refined products in the third quarter, an increase of approximately 37,000 bbls/d compared with the same period a year ago primarily due to higher throughput and increased yields as a result of the Wood River Refinery's Coker and Refinery Expansion (CORE) project.
- Combined crude oil consumption at the Wood River Refinery and Borger Refinery averaged 442,000 bbls/d gross for the quarter, an increase of 7% compared with the same period a year earlier.
- Canadian heavy crude processed at the Wood River Refinery in the quarter continued to average approximately 200,000 bbls/d gross, including almost 28,000 bbls/d of CDB. Total processing capability of heavy Canadian crudes will be dependent upon the quality of available crudes and will be managed to maximize economic benefit.
- Third quarter operating cash flow from refining operations was \$530 million, an increase of \$297 million compared with the same period last year. This was primarily due to increased throughput of heavy crude oil, favourable discounts on inland crudes and higher market crack spreads.
- 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 third quarter would have been \$6 million lower than under FIFO, compared with \$69 million higher in 2011.
- Cenovus invested \$37 million in its refining operations in the quarter, resulting in \$493 million of operating cash flow in excess of the capital spent on the refineries.
- Scheduled maintenance turnarounds at the Wood River and Borger refineries are currently underway and are proceeding as planned, with return to full operations expected in November. The resulting reductions in crude oil processing are reflected in the company's revised refining operating cash flow guidance.
- Cenovus has increased its 2012 full-year guidance for operating cash flow from its refining operations by 38%. Updated guidance can be found at www.cenovus.com under "Invest in us".

Financial

Dividend

The Cenovus Board of Directors declared a fourth quarter dividend of \$0.22 per share, payable on December 31, 2012 to common shareholders of record as of December 14, 2012. Based on the October 24, 2012 closing share price on the Toronto Stock Exchange of \$34.00, 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 a meaningful 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 achieve more predictability around cash flow and safeguard its capital program. The strategy allows the company to financially hedge up to 75% of expected natural gas production in 2012 and 2013, 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 for 2012 and 2013 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 natural gas production. About 125 MMcf/d of natural gas is currently 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 as at September 30, 2012 include:

- approximately 30% of expected 2012 oil production hedged; 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
- 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 about 125 MMcf/d of internal usage
- 18,500 bbls/d of expected oil production hedged for 2013 at an average Brent price of US\$110.36/bbl and an additional 18,500 bbls/d at an average Brent price of C\$111.72/bbl
- 166 MMcf/d of expected natural gas production hedged for 2013 at an average NYMEX price of US\$4.64/Mcf, plus internal usage
- no fixed price commodity hedges in place beyond 2013.

During the third quarter, Cenovus converted all of its existing 2013 crude oil hedges from WTI to Brent and added additional hedging contracts at Brent pricing. While WTI has historically been the dominant benchmark for North American crude oil, inland refined products have now become more strongly correlated to Brent pricing. Because of its exposure to refined products through its joint ownership in two U.S. refineries, Cenovus has decided to move its crude oil hedges to Brent pricing to better reflect its integrated structure and exposure to market risk.

Financial Highlights

- During the third quarter, Cenovus completed a US\$1.25 billion debt offering in the U.S. of 10 and 30-year senior unsecured notes and renegotiated its existing \$3 billion credit facility, extending the maturity date to November 30, 2016 and slightly reducing the cost of future borrowings under the facility.
- Cash flow in the third quarter of 2012 was more than \$1.1 billion, or \$1.47 per share diluted, compared with \$793 million, or \$1.05 per share diluted, for the same period a year earlier.

- Operating earnings in the quarter were \$432 million, or \$0.57 per share diluted, compared with \$303 million, or \$0.40 per share diluted, for the same period last year.
- Cenovus's realized after-tax hedging gains were \$73 million in the quarter. Cenovus received an average realized price, including hedging, of \$67.40/bbl for its oil in the quarter, compared with \$68.13/bbl in the third quarter of 2011. The average realized price, including hedging, for natural gas was \$3.54/Mcf, compared with \$4.48/Mcf in the same period a year earlier.
- Cenovus recorded an income tax expense of \$186 million in the third quarter, a \$108 million decrease over the previous year. The decrease was primarily due to a deferred tax recovery associated with unrealized hedging losses offset by deferred tax on increased refining income.
- Cenovus's net earnings for the quarter were \$289 million, compared with \$510 million in the same period a year earlier. The decrease was primarily due to an unrealized after-tax risk management loss of \$218 million in the third quarter compared to an unrealized after-tax risk management gain of \$283 million in the same period a year earlier. Cenovus also recorded a \$60 million unrealized foreign exchange gain in the third quarter of 2012, compared to an unrealized foreign exchange loss of \$63 million in the third quarter of 2011.
- Capital investment during the quarter was \$830 million, as planned, a 32% increase compared with the same period a year earlier as the company continues to advance the development of its oil opportunities.
- 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 September 30, 2012, the company's debt to capitalization ratio was 31% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.1 times.

Earnings Reconciliation Summary				
(for the period ended September 30) (\$ millions, except per share amounts)	2012 Q3	2011 Q3	9 months 2012	9 months 2011
Net earnings	289	510	1,111	1,212
Add back (losses) & deduct gains: Per share diluted	0.38	0.67	1.46	1.60
Unrealized mark-to-market hedging gain (loss), after tax	-218	283	-44	314
Non-operating foreign exchange gain (loss), after tax	76	-76	100	-11
Divestiture gain (loss), after tax	-1	-	-	2
Operating earnings	432	303	1,055	907
Per share diluted	0.57	0.40	1.39	1.20

Notice of Change of Transfer Agent and Registrar

Effective **November 1, 2012**, Computershare Investor Services Inc. will replace CIBC Mellon Trust Company as Transfer Agent and Registrar, Dividend Disbursing Agent, Dividend Reinvestment Plan Agent and Shareholder Rights Plan Agent for Cenovus Energy Inc. No action is required as a result of this transition. Additional information is available at www.cenovus.com under Invest in us, Shareholder information.

Management's Discussion and Analysis

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

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

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

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

Our operational focus is to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Alberta and Saskatchewan, and to continue the assessment and development of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

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

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

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

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

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

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

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

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which includes the development and production of conventional Crude Oil and natural gas in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.
- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

OVERVIEW OF THE THIRD QUARTER OF 2012

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

OPERATIONAL RESULTS

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

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

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

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

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

FINANCIAL RESULTS

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

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

- Revenues increasing \$482 million or 12 percent as a result of:
 - Refining and Marketing revenues rising \$375 million due primarily to higher refinery output;
 - Crude Oil sales volumes increasing 27 percent; and
 - Increased condensate volumes used for blending partially offset by lower condensate prices.Partially offsetting these increases in revenues were:
 - Crude oil average sales prices (excluding financial hedging) decreasing three percent; and
 - Natural gas revenues decreasing \$102 million due to declining production and lower average sales prices.
- Operating cash flow of \$1,310 million, increasing \$365 million due to:
 - Operating cash flow from upstream operations of \$783 million, an improvement of \$76 million due to higher Crude Oil volumes, despite lower realized prices, which was partially offset by lower natural gas prices and volumes;
 - Operating cash flow of \$527 million from our Refining and Marketing segment, increasing \$289 million. The continuation of high market crack spreads, the ability to process significantly higher volumes of heavy crude oil subsequent to the coker start-up of the CORE project at the Wood River Refinery and favourable discounts on inland crude feedstock resulted in very strong quarterly refining margins;
- Total cash flow of \$1,117 million, increasing 41 percent primarily as a result of higher operating cash flow from our refining operations and Crude Oil due to higher production, offset by lower operating cash flow from natural gas operations as a result of lower sales prices and volumes;
- Operating earnings of \$432 million, increasing \$129 million, primarily due to higher operating cash flow partially offset by:
 - Increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates;
 - Increased general and administrative costs due to higher long-term incentive costs compared to a recovery of long-term incentive costs in the third quarter of 2011; and
 - Higher income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures) from increased operating cash flow from upstream and refining operations;
- Capital investment of \$830 million focusing on the expansion of our producing oil sands operations and the development of tight oil opportunities in southern Alberta and Saskatchewan;
- Our conventional natural gas operations generating \$111 million of operating cash flow in excess of related capital investment, used to partially fund the future development of our crude oil projects;
- Completing a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US\$1.25 billion; and
- Paying a quarterly dividend of \$0.22 per share (2011 – \$0.20 per share).

OUR BUSINESS ENVIRONMENT

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

Selected Benchmark Prices and Exchange Rates ⁽¹⁾

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

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

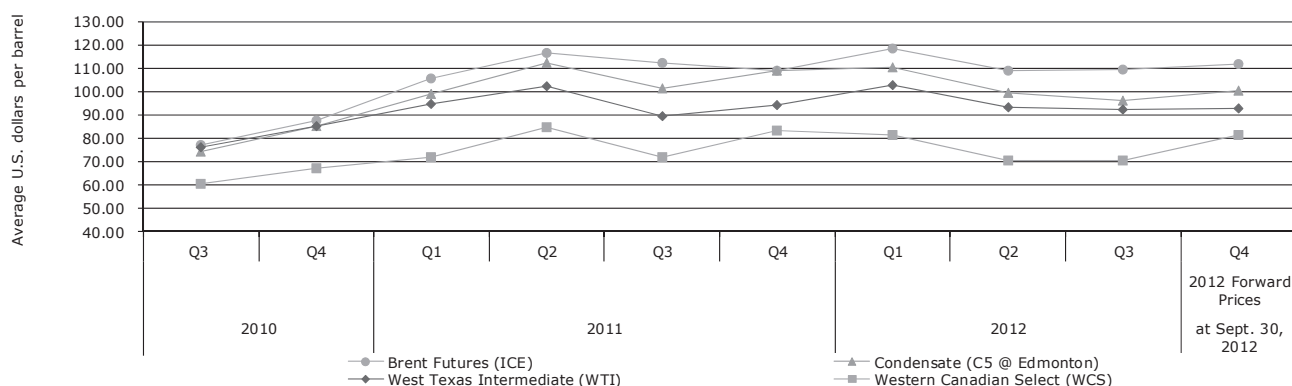
⁽²⁾ 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel, and reflects the current month WTI price as the crude oil feedstock price.

Crude Oil Benchmarks

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

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

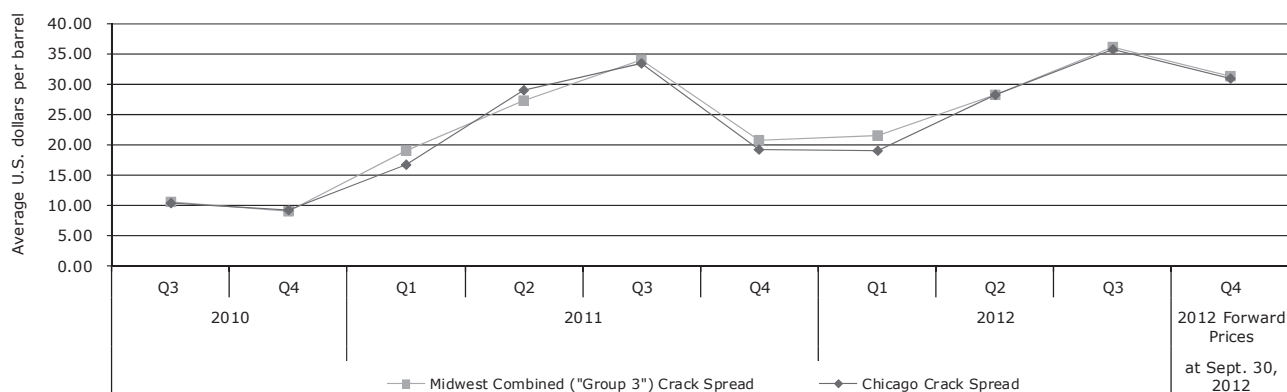
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark, WTI. The WTI-WCS average differential narrowed slightly in the third quarter of 2012 from the second quarter, primarily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



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

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 using current month WTI based crude oil feedstock prices. Average crack spreads in the U.S. inland Chicago and Group 3 markets in the third quarter of 2012 increased from already strong second quarter levels due to increased inland crude oil discounts, refinery closures and above normal refinery outages.



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

Other Benchmarks

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

continued growth in associated gas produced with liquids, completion of previously drilled wells and increased supply due to ethane being left in the gas stream from ethane infrastructure constraints predominately in the Marcellus basin.

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

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

FINANCIAL INFORMATION

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

SELECTED CONSOLIDATED FINANCIAL RESULTS

(millions of dollars, except per share amounts)	Nine Months Ended										
	September 30,		Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
	2012	2011	2012	2012	2012	2011	2011	2011	2011	2010	2010
Revenues	13,118	11,367	4,340	4,214	4,564	4,329	3,858	4,009	3,500	3,363	2,962
Operating Cash Flow ⁽¹⁾	3,473	2,843	1,310	1,078	1,085	1,019	945	1,064	834	815	661
Cash Flow ⁽¹⁾	2,946	2,425	1,117	925	904	851	793	939	693	645	509
- per share – diluted	3.88	3.20	1.47	1.22	1.19	1.12	1.05	1.24	0.91	0.85	0.68
Operating Earnings ⁽¹⁾	1,055	907	432	283	340	332	303	395	209	147	156
- per share – diluted	1.39	1.20	0.57	0.37	0.45	0.44	0.40	0.52	0.28	0.19	0.21
Net Earnings	1,111	1,212	289	396	426	266	510	655	47	78	295
- per share – basic	1.47	1.61	0.38	0.52	0.56	0.35	0.68	0.87	0.06	0.10	0.39
- per share – diluted	1.46	1.60	0.38	0.52	0.56	0.35	0.67	0.86	0.06	0.10	0.39
Capital Investment ⁽²⁾	2,390	1,820	830	660	900	903	631	476	713	701	479
Cash Dividends	498	452	166	166	166	151	150	151	151	151	150
- per share	0.66	0.60	0.22	0.22	0.22	0.20	0.20	0.20	0.20	0.20	0.20

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

⁽²⁾ Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets and excludes acquisitions and divestitures.

REVENUES VARIANCE

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

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

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

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

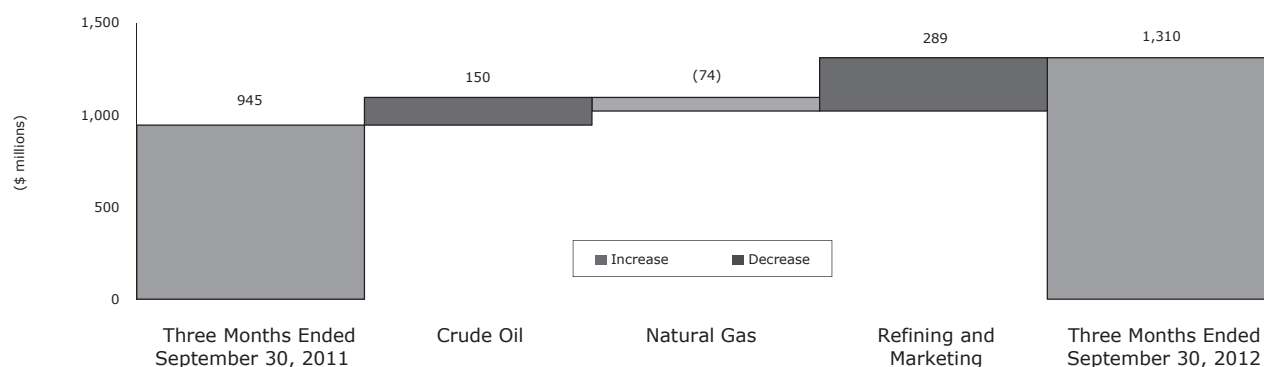
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

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

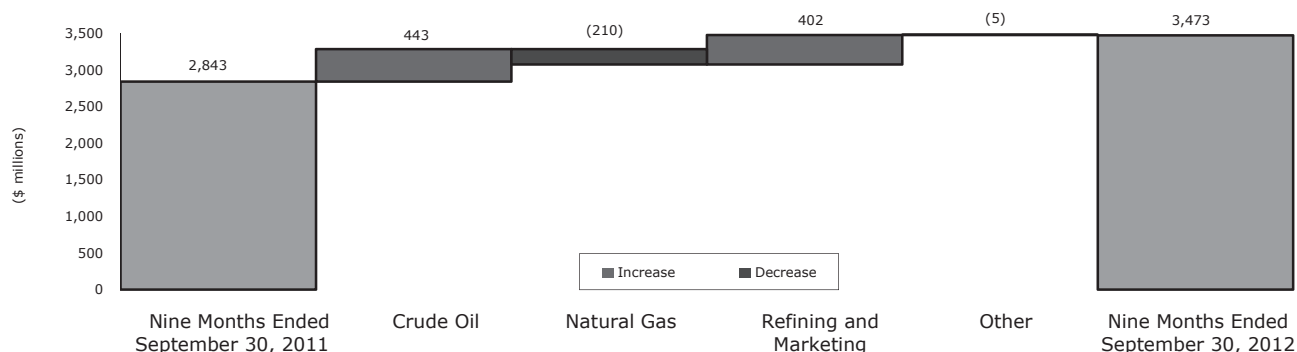
Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between periods. Operating cash flow is defined as revenues less purchased product, transportation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

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



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

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

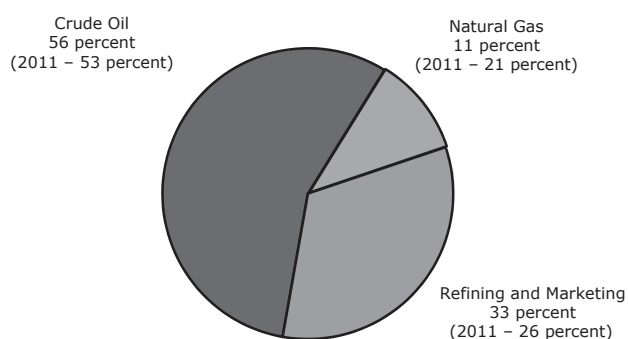


Overall, operating cash flow for the nine months ended September 30, 2012 increased \$630 million as operating cash flow from both our upstream operations and Refining and Marketing segment increased from 2011.

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

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

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



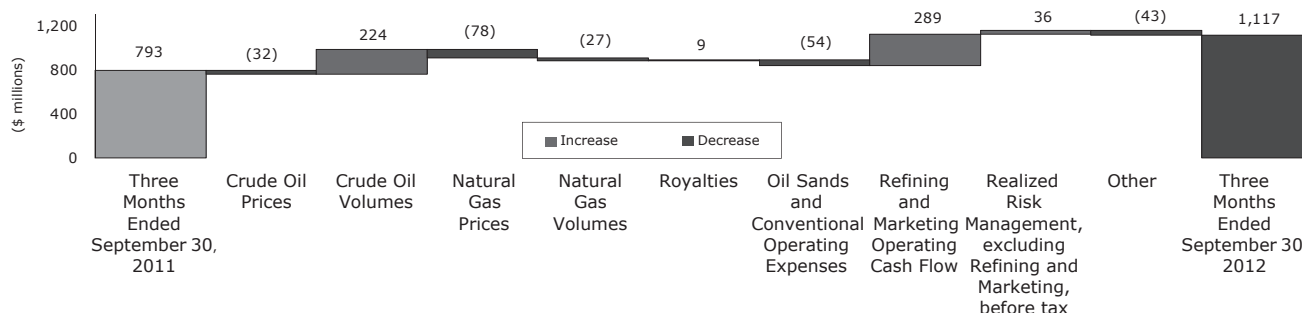
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

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

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

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



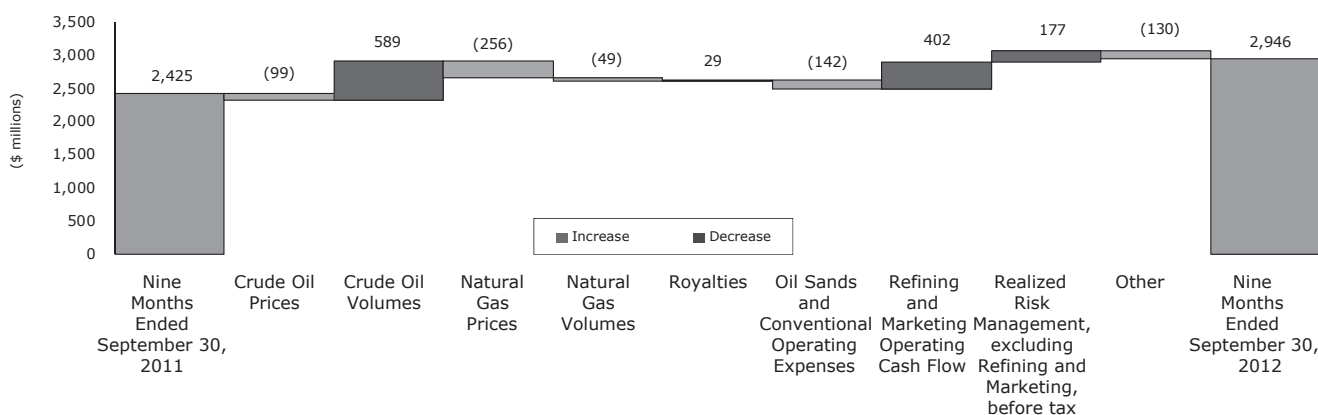
In the third quarter of 2012 our cash flow increased \$324 million primarily due to:

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

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

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

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



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

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

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

The increases in our cash flow in the nine months ended September 30, 2012 were partially offset by:

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

OPERATING EARNINGS

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

⁽¹⁾ The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.

⁽²⁾ After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax gains (losses) on unrealized non-operating foreign exchange, after-tax effect of gains (losses) on divestiture of assets and the effect of changes in statutory income tax rates. We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods.

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

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

NET EARNINGS VARIANCE

(millions of dollars)

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

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

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

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

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

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

NET CAPITAL INVESTMENT

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

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

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

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

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

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

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

Acquisitions and Divestitures

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

CAPITAL INVESTMENT DECISIONS

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

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

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

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

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

RISK MANAGEMENT ACTIVITIES

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

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

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

Financial Impact of Risk Management Activities

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

For our risk management activities, we have transitioned to a more integrated view of our exposure across the upstream and refining businesses. We recognize that on an integrated basis, we have a long position in refined product which has become more strongly correlated to Brent crude rather than WTI. To better align our corporate risk management program with this exposure, we converted all existing 2013 WTI crude oil financial instruments to Brent

during the third quarter. In addition, a further 17,000 barrels per day were executed through financial instruments at fixed Brent pricing, resulting in a total of 37,000 barrels per day locked into a weighted average Brent price of US\$111.97 per barrel. Cenovus also executed a physical long-term sales agreement with a crude oil end user for specific product grades at a fixed light to heavy differentials. Details of financial instrument volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

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

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

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

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

RESULTS OF OPERATIONS

CRUDE OIL PRODUCTION VOLUMES

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

⁽¹⁾ Natural gas liquids include condensate volumes.

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

NATURAL GAS PRODUCTION VOLUMES

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

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

OPERATING NETBACKS

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

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

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

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

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

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

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

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

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

REPORTABLE SEGMENTS

OIL SANDS

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

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

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

OIL SANDS - CRUDE OIL

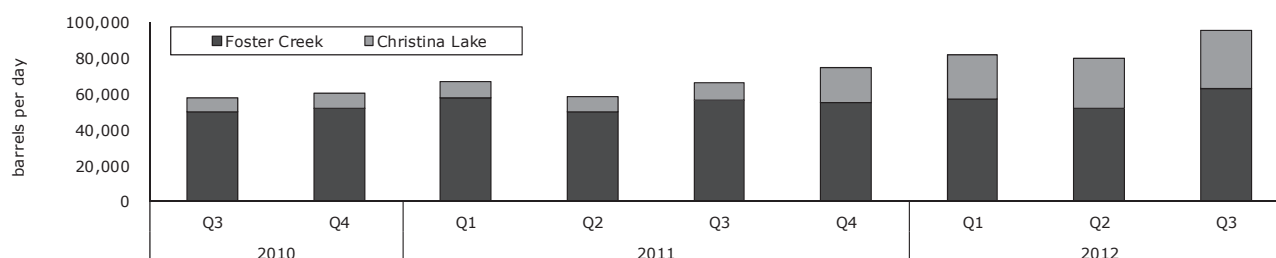
Financial Results

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

Production Volumes

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

Foster Creek and Christina Lake Production Volumes by Quarter



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

Revenues Variances

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

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

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

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

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

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

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

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

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

Revenues Variances

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

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

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

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

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

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

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

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

OIL SANDS - NATURAL GAS

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

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

OIL SANDS - CAPITAL INVESTMENT

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

⁽¹⁾ Includes emerging new resource plays and Athabasca natural gas.

⁽²⁾ Includes expenditures on PP&E and E&E assets.

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

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

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

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

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

Production Wells

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

⁽¹⁾ Includes wells drilled using our Wedge Well™ technology.

Stratigraphic Test Wells

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

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

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

CONVENTIONAL

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

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

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

CONVENTIONAL - CRUDE OIL

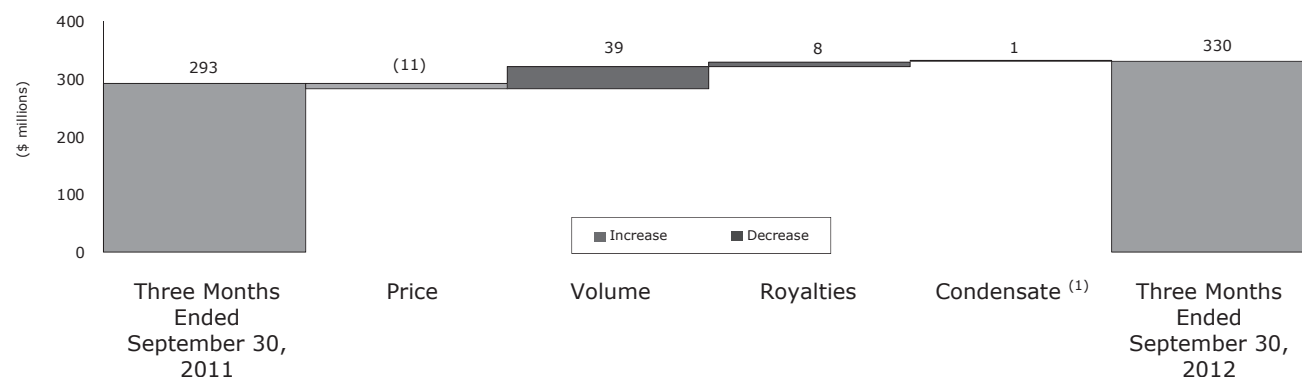
Financial Results

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

Production Volumes

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

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



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

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

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

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

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

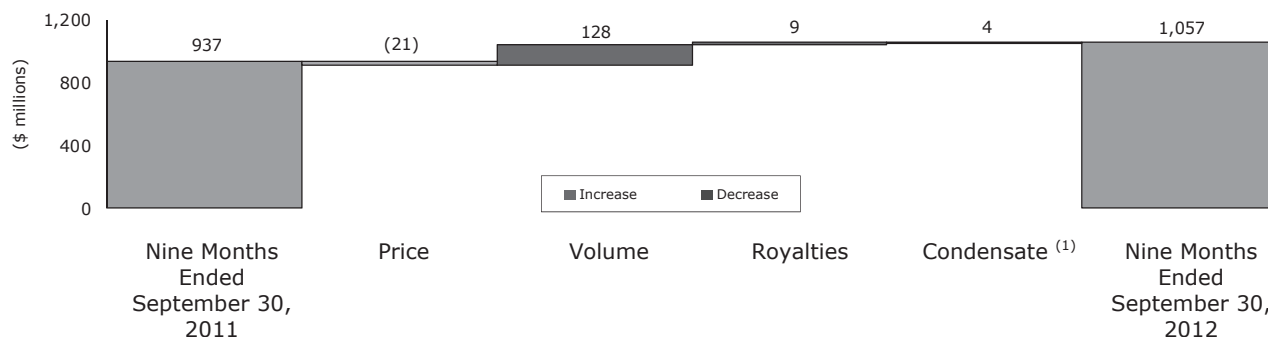
Transportation and blending costs increased \$4 million compared to 2011. The overall cost of condensate used in blending increased \$1 million. Transportation costs increased \$3 million as a higher proportion of our volumes were shipped subject to spot pipeline tolls. The costs of accessing new markets,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

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

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

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

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



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

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

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

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

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

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

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

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

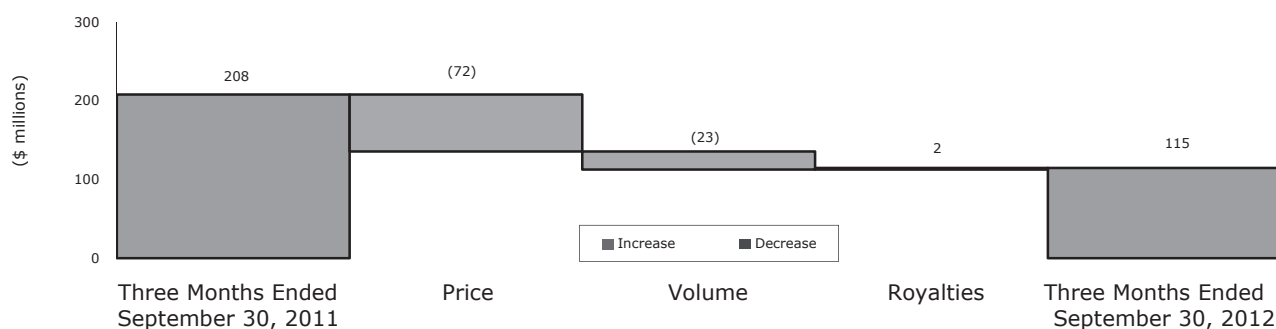
Operating cash flow from Conventional Crude Oil in excess of capital investment decreased by \$88 million in the nine months ended September 30, 2012 as the \$87 million increase in operating cash flow was more than offset by the \$175 million increase in capital investment, focused on drilling, completions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

CONVENTIONAL - NATURAL GAS

Financial Results

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

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



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

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

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

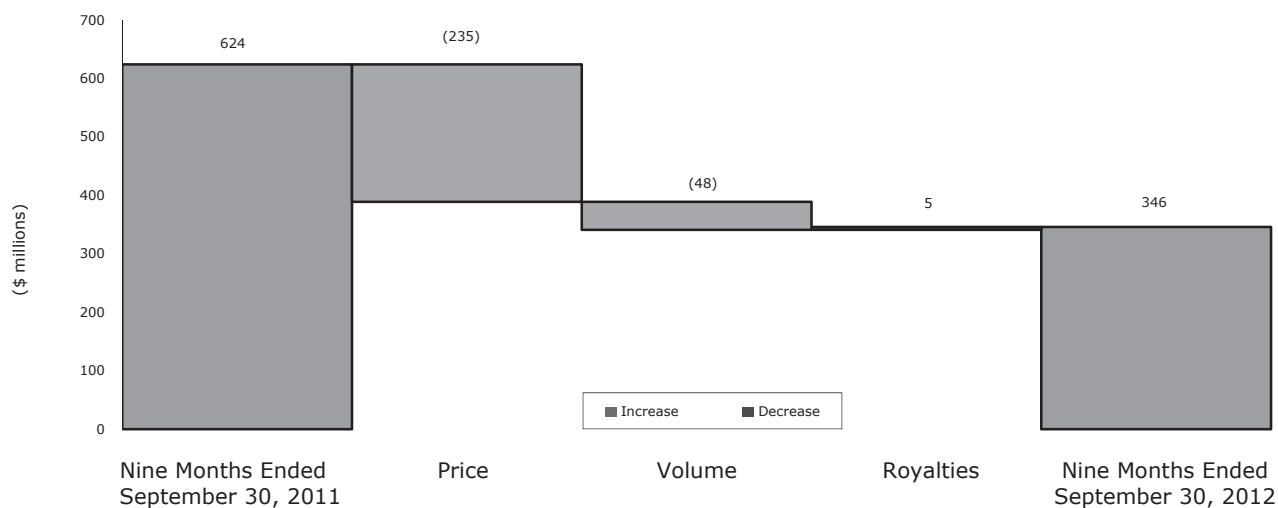
Transportation costs declined \$4 million primarily due to lower production volumes and lower transportation rates.

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

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

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

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



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

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

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

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

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

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

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

CONVENTIONAL - CAPITAL INVESTMENT

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

⁽¹⁾ Includes expenditures on PP&E and E&E assets.

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

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

Conventional Wells Drilled

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

REFINING AND MARKETING

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

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

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

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

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

Financial Results

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

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

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

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

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

REFINERY OPERATIONS ⁽¹⁾

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

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

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

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

The total processing capability of Canadian heavy crude oils remains dependent on the quality of available crude oils and will be optimized to maximize economic benefit. In the third quarter, the Wood River Refinery processed

approximately 28,000 barrels per day of CDB originating from our Christina Lake operations, further demonstrating our integrated oil strategy and the growing acceptance of CDB by refineries.

REFINING AND MARKETING - CAPITAL INVESTMENT

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

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

CORPORATE AND ELIMINATIONS

Financial Results

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

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

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

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

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

in general and administrative costs stemmed from higher long-term incentive expenses, office services as well as staffing and support costs, including training and development.

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

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

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

DEPRECIATION, DEPLETION and AMORTIZATION

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

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

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

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

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

EXPLORATION EXPENSE

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

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

INCOME TAX EXPENSE

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

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

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

OPERATING ACTIVITIES

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

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

INVESTING ACTIVITIES

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

FINANCING ACTIVITIES

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

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

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

AVAILABLE SOURCES OF LIQUIDITY

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

⁽¹⁾ Availability is subject to market conditions.

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

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of \$1.5 billion. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at September 30, 2012, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On June 6, 2012, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US\$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue.

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

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

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

FINANCIAL METRICS

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

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

We continue to have long-term targets for a debt to capitalization ratio of between 30 to 40 percent and a debt to adjusted EBITDA of between 1.0 to 2.0 times.

Our debt levels at September 30, 2012 were higher than at December 31, 2011 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter. At the end of the third quarter, our debt to capitalization and debt to adjusted EBITDA metrics, remain at the low end of our long-term target ranges. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of third preferred shares. As at September 30, 2012, approximately 755.8 million common shares were outstanding (December 31, 2011 – 754.5 million common shares) and no preferred shares were outstanding. The increase in common shares in the nine months ended September 30, 2012 was the result of stock option exercises. No other issuance of common shares has occurred in 2012.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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

LEGAL PROCEEDINGS

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

RISK MANAGEMENT

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

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

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Management monitors our risk strategies to proactively respond to changing economic conditions and to prevent or mitigate risk. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

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

FINANCIAL RISKS

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

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

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

OPERATIONAL RISKS

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

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

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

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

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

REGULATORY RISKS

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

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

Environmental Regulation Risk

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

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

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

Alberta's Regulatory Framework

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

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

TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

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

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

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

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

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

ACCOUNTING POLICIES AND ESTIMATES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

FUTURE CHANGES IN ACCOUNTING POLICIES

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

OUTLOOK

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

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

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

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

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

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

- Growing oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and we have a 100 percent working interest in many of these assets;

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

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

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

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

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

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended September 30,
(\$ millions, except per share amounts)

	Notes	Three Months Ended		Nine Months Ended	
		2012	2011	2012	2011
Revenues	1				
Gross sales		4,462	3,989	13,427	11,705
Less: Royalties		122	131	309	338
		<u>4,340</u>	<u>3,858</u>	<u>13,118</u>	<u>11,367</u>
Expenses	1				
Purchased product		2,303	2,348	7,335	6,559
Transportation and blending		398	294	1,323	973
Operating		418	340	1,201	1,020
Production and mineral taxes		9	9	28	27
(Gain) loss on risk management	18	194	(460)	(184)	(478)
Depreciation, depletion and amortization		397	318	1,176	912
Exploration expense	10	-	-	68	-
General and administrative		104	38	254	206
Finance costs	3	120	112	344	335
Interest income	4	(28)	(31)	(84)	(94)
Foreign exchange (gain) loss, net	5	(51)	85	(42)	56
(Gain) loss on divestiture of assets		1	-	-	(3)
Other (income) loss, net		-	1	(4)	1
		<u>475</u>	<u>804</u>	<u>1,703</u>	<u>1,853</u>
Earnings Before Income Tax					
Income tax expense	6	186	294	592	641
		<u>289</u>	<u>510</u>	<u>1,111</u>	<u>1,212</u>
Net Earnings					
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment		(45)	100	(36)	73
		<u>244</u>	<u>610</u>	<u>1,075</u>	<u>1,285</u>
Comprehensive Income					
Net Earnings per Common Share	7				
Basic		\$ 0.38	\$ 0.68	\$ 1.47	\$ 1.61
Diluted		\$ 0.38	\$ 0.67	\$ 1.46	\$ 1.60

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
(\$ millions)

	Notes	September 30, 2012	December 31, 2011
Assets			
Current Assets			
Cash and cash equivalents		1,543	495
Accounts receivable and accrued revenues		1,765	1,405
Current portion of Partnership Contribution Receivable		375	372
Inventories	8	1,221	1,291
Risk management	18	163	232
Assets held for sale	9	-	116
		5,067	3,911
Current Assets			
Exploration and Evaluation Assets	1,10	1,269	880
Property, Plant and Equipment, net	1,11	15,353	14,324
Partnership Contribution Receivable		1,479	1,822
Risk Management	18	31	52
Income Tax Receivable		-	29
Other Assets		53	44
Goodwill	1	1,132	1,132
Total Assets		24,384	22,194
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		2,760	2,579
Income tax payable		234	329
Current portion of Partnership Contribution Payable		376	372
Risk management	18	39	54
Liabilities related to assets held for sale	9	-	54
		3,409	3,388
Current Liabilities			
Long-Term Debt	12	4,626	3,527
Partnership Contribution Payable		1,508	1,853
Risk Management	18	4	14
Decommissioning Liabilities	13	2,126	1,777
Other Liabilities		153	128
Deferred Income Taxes		2,494	2,101
		14,320	12,788
Total Liabilities		14,320	12,788
Shareholders' Equity		10,064	9,406
Total Liabilities and Shareholders' Equity		24,384	22,194

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(unaudited)
(\$ millions)

	Share Capital (Note 14)	Paid in Surplus	Retained Earnings	AOCI*	Total
Balance as at December 31, 2010	3,716	4,083	525	71	8,395
Net earnings	-	-	1,212	-	1,212
Other comprehensive income (loss)	-	-	-	73	73
Total comprehensive income (loss) for the period	-	-	1,212	73	1,285
Common shares issued under option plans	59	-	-	-	59
Stock-based compensation expense	-	17	-	-	17
Dividends on common shares	-	-	(452)	-	(452)
Balance as at September 30, 2011	3,775	4,100	1,285	144	9,304
Balance as at December 31, 2011	3,780	4,107	1,400	119	9,406
Net earnings	-	-	1,111	-	1,111
Other comprehensive income (loss)	-	-	-	(36)	(36)
Total comprehensive income (loss) for the period	-	-	1,111	(36)	1,075
Common shares issued under option plans	47	-	-	-	47
Stock-based compensation expense	-	34	-	-	34
Dividends on common shares	-	-	(498)	-	(498)
Balance as at September 30, 2012	3,827	4,141	2,013	83	10,064

* Accumulated Other Comprehensive Income.

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended September 30,
(\$ millions)

	Notes	Three Months Ended		Nine Months Ended	
		2012	2011	2012	2011
Operating Activities					
Net earnings		289	510	1,111	1,212
Depreciation, depletion and amortization		397	318	1,176	912
Exploration expense		-	-	68	-
Deferred income taxes	6	110	258	408	551
Unrealized (gain) loss on risk management	18	293	(381)	60	(422)
Unrealized foreign exchange (gain) loss	5	(60)	63	(82)	1
(Gain) loss on divestiture of assets		1	-	-	(3)
Unwinding of discount on decommissioning liabilities	3,13	22	19	64	56
Other		65	6	141	118
		<u>1,117</u>	<u>793</u>	<u>2,946</u>	<u>2,425</u>
Net change in other assets and liabilities		(19)	(17)	(71)	(62)
Net change in non-cash working capital		(69)	145	(213)	(42)
Cash From Operating Activities		<u>1,029</u>	<u>921</u>	<u>2,662</u>	<u>2,321</u>
Investing Activities					
Capital expenditures – exploration and evaluation assets	10	(104)	(39)	(451)	(341)
Capital expenditures – property, plant and equipment	11	(734)	(593)	(1,983)	(1,498)
Proceeds from divestiture of assets		-	-	65	8
Net change in investments and other		5	1	(10)	(21)
Net change in non-cash working capital		92	48	18	(7)
Cash (Used in) Investing Activities		<u>(741)</u>	<u>(583)</u>	<u>(2,361)</u>	<u>(1,859)</u>
Net Cash Provided (Used) before Financing Activities		<u>288</u>	<u>338</u>	<u>301</u>	<u>462</u>
Financing Activities					
Net issuance (repayment) of short-term borrowings		(204)	(87)	3	(3)
Issuance of long-term debt		1,219	-	1,219	-
Proceeds on issuance of common shares		3	6	35	44
Dividends paid on common shares	7	(166)	(150)	(498)	(452)
Other		-	(3)	1	(3)
Cash From (Used in) Financing Activities		<u>852</u>	<u>(234)</u>	<u>760</u>	<u>(414)</u>
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		<u>(6)</u>	<u>9</u>	<u>(13)</u>	<u>10</u>
Increase (Decrease) in Cash and Cash Equivalents		<u>1,134</u>	<u>113</u>	<u>1,048</u>	<u>58</u>
Cash and Cash Equivalents, Beginning of Period		<u>409</u>	<u>245</u>	<u>495</u>	<u>300</u>
Cash and Cash Equivalents, End of Period		<u>1,543</u>	<u>358</u>	<u>1,543</u>	<u>358</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 Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

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 September 30, 2012

A) Results of Operations - Segment and Operational Information (For the Three Months Ended September 30)

	Oil Sands		Conventional		Refining and Marketing	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	1,007	754	489	553	3,066	2,691
Less: Royalties	83	82	39	49	-	-
	924	672	450	504	3,066	2,691
Expenses						
Purchased product	-	-	-	-	2,403	2,357
Transportation and blending	367	263	31	31	-	-
Operating	150	108	133	121	136	112
Production and mineral taxes	-	-	9	9	-	-
(Gain) loss on risk management	(28)	(12)	(71)	(51)	-	(16)
Operating Cash Flow	435	313	348	394	527	238
Depreciation, depletion and amortization	127	93	222	195	36	20
Exploration expense	-	-	-	-	-	-
Segment Income (Loss)	308	220	126	199	491	218
			Corporate and Eliminations		Consolidated	
			2012	2011	2012	2011
Revenues						
Gross sales			(100)	(9)	4,462	3,989
Less: Royalties			-	-	122	131
			(100)	(9)	4,340	3,858
Expenses						
Purchased product			(100)	(9)	2,303	2,348
Transportation and blending			-	-	398	294
Operating			(1)	(1)	418	340
Production and mineral taxes			-	-	9	9
(Gain) loss on risk management			293	(381)	194	(460)
			(292)	382	1,018	1,327
Depreciation, depletion and amortization			12	10	397	318
Exploration expense			-	-	-	-
Segment Income (Loss)			(304)	372	621	1,009
General and administrative			104	38	104	38
Finance costs			120	112	120	112
Interest income			(28)	(31)	(28)	(31)
Foreign exchange (gain) loss, net			(51)	85	(51)	85
(Gain) loss on divestiture of assets			1	-	1	-
Other (income) loss, net			-	1	-	1
			146	205	146	205
Earnings Before Income Tax					475	804
Income tax expense					186	294
Net Earnings					289	510

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

B) Financial Results by Upstream Product (For the Three Months Ended September 30)

	Oil Sands		Crude Oil and NGLs		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	998	736	368	339	1,366	1,075
Less: Royalties	84	82	38	46	122	128
	<u>914</u>	<u>654</u>	<u>330</u>	<u>293</u>	<u>1,244</u>	<u>947</u>
Expenses						
Transportation and blending	367	263	27	23	394	286
Operating	142	103	78	61	220	164
Production and mineral taxes	-	-	7	7	7	7
(Gain) loss on risk management	(23)	(8)	(9)	(7)	(32)	(15)
Operating Cash Flow	<u>428</u>	<u>296</u>	<u>227</u>	<u>209</u>	<u>655</u>	<u>505</u>
Natural Gas						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	7	17	116	211	123	228
Less: Royalties	(1)	-	1	3	-	3
	<u>8</u>	<u>17</u>	<u>115</u>	<u>208</u>	<u>123</u>	<u>225</u>
Expenses						
Transportation and blending	-	-	4	8	4	8
Operating	5	4	53	59	58	63
Production and mineral taxes	-	-	2	2	2	2
(Gain) loss on risk management	(5)	(4)	(62)	(44)	(67)	(48)
Operating Cash Flow	<u>8</u>	<u>17</u>	<u>118</u>	<u>183</u>	<u>126</u>	<u>200</u>
Other						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	2	1	5	3	7	4
Less: Royalties	-	-	-	-	-	-
	<u>2</u>	<u>1</u>	<u>5</u>	<u>3</u>	<u>7</u>	<u>4</u>
Expenses						
Transportation and blending	-	-	-	-	-	-
Operating	3	1	2	1	5	2
Production and mineral taxes	-	-	-	-	-	-
(Gain) loss on risk management	-	-	-	-	-	-
Operating Cash Flow	<u>(1)</u>	<u>-</u>	<u>3</u>	<u>2</u>	<u>2</u>	<u>2</u>
Total Upstream						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	1,007	754	489	553	1,496	1,307
Less: Royalties	83	82	39	49	122	131
	<u>924</u>	<u>672</u>	<u>450</u>	<u>504</u>	<u>1,374</u>	<u>1,176</u>
Expenses						
Transportation and blending	367	263	31	31	398	294
Operating	150	108	133	121	283	229
Production and mineral taxes	-	-	9	9	9	9
(Gain) loss on risk management	(28)	(12)	(71)	(51)	(99)	(63)
Operating Cash Flow	<u>435</u>	<u>313</u>	<u>348</u>	<u>394</u>	<u>783</u>	<u>707</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

C) Geographic Information (For the Three Months Ended September 30)

	Canada		United States		Consolidated	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	2,006	1,768	2,456	2,221	4,462	3,989
Less: Royalties	122	131	-	-	122	131
	<u>1,884</u>	<u>1,637</u>	<u>2,456</u>	<u>2,221</u>	<u>4,340</u>	<u>3,858</u>
Expenses						
Purchased product	502	452	1,801	1,896	2,303	2,348
Transportation and blending	398	294	-	-	398	294
Operating	289	232	129	108	418	340
Production and mineral taxes	9	9	-	-	9	9
(Gain) loss on risk management	189	(429)	5	(31)	194	(460)
	<u>497</u>	<u>1,079</u>	<u>521</u>	<u>248</u>	<u>1,018</u>	<u>1,327</u>
Depreciation, depletion and amortization	361	298	36	20	397	318
Exploration expense	-	-	-	-	-	-
Segment Income (Loss)	<u>136</u>	<u>781</u>	<u>485</u>	<u>228</u>	<u>621</u>	<u>1,009</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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

D) Results of Operations - Segment and Operational Information (For the Nine Months Ended September 30)

	<u>Oil Sands</u>		<u>Conventional</u>		<u>Refining and Marketing</u>	
	<u>2012</u>	<u>2011</u>	<u>2012</u>	<u>2011</u>	<u>2012</u>	<u>2011</u>
Revenues						
Gross sales	3,026	2,340	1,546	1,717	9,020	7,698
Less: Royalties	175	190	134	148	-	-
	<u>2,851</u>	<u>2,150</u>	<u>1,412</u>	<u>1,569</u>	<u>9,020</u>	<u>7,698</u>
Expenses						
Purchased product	-	-	-	-	7,500	6,609
Transportation and blending	1,212	869	111	104	-	-
Operating	432	321	382	351	389	349
Production and mineral taxes	-	-	28	27	-	-
(Gain) loss on risk management	(35)	49	(195)	(102)	(14)	(3)
Operating Cash Flow	<u>1,242</u>	<u>911</u>	<u>1,086</u>	<u>1,189</u>	<u>1,145</u>	<u>743</u>
Depreciation, depletion and amortization	352	254	680	575	109	54
Exploration expense	-	-	68	-	-	-
Segment Income (Loss)	<u>890</u>	<u>657</u>	<u>338</u>	<u>614</u>	<u>1,036</u>	<u>689</u>
			<u>Corporate and Eliminations</u>		<u>Consolidated</u>	
			<u>2012</u>	<u>2011</u>	<u>2012</u>	<u>2011</u>
Revenues						
Gross sales			(165)	(50)	13,427	11,705
Less: Royalties			-	-	309	338
			<u>(165)</u>	<u>(50)</u>	<u>13,118</u>	<u>11,367</u>
Expenses						
Purchased product			(165)	(50)	7,335	6,559
Transportation and blending			-	-	1,323	973
Operating			(2)	(1)	1,201	1,020
Production and mineral taxes			-	-	28	27
(Gain) loss on risk management			60	(422)	(184)	(478)
			<u>(58)</u>	<u>423</u>	<u>3,415</u>	<u>3,266</u>
Depreciation, depletion and amortization			35	29	1,176	912
Exploration expense			-	-	68	-
Segment Income (Loss)			<u>(93)</u>	<u>394</u>	<u>2,171</u>	<u>2,354</u>
General and administrative			254	206	254	206
Finance costs			344	335	344	335
Interest income			(84)	(94)	(84)	(94)
Foreign exchange (gain) loss, net			(42)	56	(42)	56
(Gain) loss on divestiture of assets			-	(3)	-	(3)
Other (income) loss, net			(4)	1	(4)	1
			<u>468</u>	<u>501</u>	<u>468</u>	<u>501</u>
Earnings Before Income Tax					<u>1,703</u>	<u>1,853</u>
Income tax expense					<u>592</u>	<u>641</u>
Net Earnings					<u>1,111</u>	<u>1,212</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

E) Financial Results by Upstream Product (For the Nine Months Ended September 30)

	Oil Sands		Crude Oil and NGLs		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	2,994	2,286	1,187	1,076	4,181	3,362
Less: Royalties	175	189	130	139	305	328
	<u>2,819</u>	<u>2,097</u>	<u>1,057</u>	<u>937</u>	<u>3,876</u>	<u>3,034</u>
Expenses						
Transportation and blending	1,211	868	96	78	1,307	946
Operating	405	301	224	175	629	476
Production and mineral taxes	-	-	24	19	24	19
(Gain) loss on risk management	(20)	61	(9)	30	(29)	91
Operating Cash Flow	<u>1,223</u>	<u>867</u>	<u>722</u>	<u>635</u>	<u>1,945</u>	<u>1,502</u>
Natural Gas						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	25	47	350	633	375	680
Less: Royalties	-	1	4	9	4	10
	<u>25</u>	<u>46</u>	<u>346</u>	<u>624</u>	<u>371</u>	<u>670</u>
Expenses						
Transportation and blending	1	1	15	26	16	27
Operating	18	17	155	173	173	190
Production and mineral taxes	-	-	4	8	4	8
(Gain) loss on risk management	(15)	(12)	(186)	(132)	(201)	(144)
Operating Cash Flow	<u>21</u>	<u>40</u>	<u>358</u>	<u>549</u>	<u>379</u>	<u>589</u>
Other						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	7	7	9	8	16	15
Less: Royalties	-	-	-	-	-	-
	<u>7</u>	<u>7</u>	<u>9</u>	<u>8</u>	<u>16</u>	<u>15</u>
Expenses						
Transportation and blending	-	-	-	-	-	-
Operating	9	3	3	3	12	6
Production and mineral taxes	-	-	-	-	-	-
(Gain) loss on risk management	-	-	-	-	-	-
Operating Cash Flow	<u>(2)</u>	<u>4</u>	<u>6</u>	<u>5</u>	<u>4</u>	<u>9</u>
Total Upstream						
	Oil Sands		Conventional		Total	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	3,026	2,340	1,546	1,717	4,572	4,057
Less: Royalties	175	190	134	148	309	338
	<u>2,851</u>	<u>2,150</u>	<u>1,412</u>	<u>1,569</u>	<u>4,263</u>	<u>3,719</u>
Expenses						
Transportation and blending	1,212	869	111	104	1,323	973
Operating	432	321	382	351	814	672
Production and mineral taxes	-	-	28	27	28	27
(Gain) loss on risk management	(35)	49	(195)	(102)	(230)	(53)
Operating Cash Flow	<u>1,242</u>	<u>911</u>	<u>1,086</u>	<u>1,189</u>	<u>2,328</u>	<u>2,100</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

F) Geographic Information (For the Nine Months Ended September 30)

	Canada		United States		Consolidated	
	2012	2011	2012	2011	2012	2011
Revenues						
Gross sales	6,059	5,412	7,368	6,293	13,427	11,705
Less: Royalties	309	338	-	-	309	338
	5,750	5,074	7,368	6,293	13,118	11,367
Expenses						
Purchased product	1,466	1,330	5,869	5,229	7,335	6,559
Transportation and blending	1,323	973	-	-	1,323	973
Operating	830	688	371	332	1,201	1,020
Production and mineral taxes	28	27	-	-	28	27
(Gain) loss on risk management	(169)	(459)	(15)	(19)	(184)	(478)
	2,272	2,515	1,143	751	3,415	3,266
Depreciation, depletion and amortization	1,067	858	109	54	1,176	912
Exploration expense	68	-	-	-	68	-
Segment Income (Loss)	1,137	1,657	1,034	697	2,171	2,354

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.

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

By Segment

As at	Exploration and Evaluation Assets		Property, Plant and Equipment	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Oil Sands	1,148	741	7,128	6,224
Conventional	121	139	4,848	4,668
Refining and Marketing	-	-	3,047	3,200
Corporate and Eliminations	-	-	330	232
Consolidated	1,269	880	15,353	14,324
As at	Goodwill		Total Assets	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Oil Sands	739	739	11,532	10,524
Conventional	393	393	5,580	5,566
Refining and Marketing	-	-	5,069	4,927
Corporate and Eliminations	-	-	2,203	1,177
Consolidated	1,132	1,132	24,384	22,194

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended September 30, 2012

By Geographic Region

As at	Exploration and Evaluation Assets		Property, Plant and Equipment	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Canada	1,269	880	12,307	11,124
United States	-	-	3,046	3,200
Consolidated	1,269	880	15,353	14,324

As at	Goodwill		Total Assets	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Canada	1,132	1,132	19,848	17,536
United States	-	-	4,536	4,658
Consolidated	1,132	1,132	24,384	22,194

H) Capital Expenditures

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Capital				
Oil Sands	516	306	1,606	950
Conventional	231	193	591	458
Refining and Marketing	38	101	60	320
Corporate	45	31	133	92
	830	631	2,390	1,820
Acquisition Capital				
Oil Sands	2	-	2	4
Conventional	6	1	42	15
Corporate	-	-	-	3
Total	838	632	2,434	1,842

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 methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2011 except for income taxes on earnings in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. 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 effective October 24, 2012.

3. FINANCE COSTS

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	59	54	166	160
Interest Expense – Partnership Contribution Payable	29	34	91	104
Unwinding of Discount on Decommissioning Liabilities	22	19	64	56
Other	10	5	23	15
	<u>120</u>	<u>112</u>	<u>344</u>	<u>335</u>

4. INTEREST INCOME

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Interest Income – Partnership Contribution Receivable	(25)	(30)	(79)	(91)
Other	(3)	(1)	(5)	(3)
	<u>(28)</u>	<u>(31)</u>	<u>(84)</u>	<u>(94)</u>

5. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Unrealized Foreign Exchange (Gain) Loss on translation of:				
U.S. dollar debt issued from Canada	(129)	261	(122)	155
U.S. dollar Partnership Contribution Receivable issued from Canada	53	(185)	22	(144)
Other	16	(13)	18	(10)
Unrealized Foreign Exchange (Gain) Loss	(60)	63	(82)	1
Realized Foreign Exchange (Gain) Loss	9	22	40	55
	<u>(51)</u>	<u>85</u>	<u>(42)</u>	<u>56</u>

6. INCOME TAXES

The provision for income taxes is as follows:

For the period ended September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
Current Tax				
Canada	56	35	139	88
United States	20	1	45	2
Total Current Tax	76	36	184	90
Deferred Tax	110	258	408	551
	<u>186</u>	<u>294</u>	<u>592</u>	<u>641</u>

7. PER SHARE AMOUNTS

A) Net Earnings per Share

For the three months ended (\$ millions, except earnings per share)	September 30, 2012			September 30, 2011		
	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	289	755.7	\$0.38	510	754.3	\$0.68
Dilutive effect of Cenovus TSARs	-	2.3		-	3.5	
Net earnings per share – diluted	289	758.0	\$0.38	510	757.8	\$0.67

For the nine months ended (\$ millions, except earnings per share)	September 30, 2012			September 30, 2011		
	Net Earnings	Shares	Earnings per Share	Net Earnings	Shares	Earnings per Share
Net earnings per share – basic	1,111	755.5	\$1.47	1,212	753.9	\$1.61
Dilutive effect of Cenovus TSARs	-	3.0		-	4.0	
Net earnings per share – diluted	1,111	758.5	\$1.46	1,212	757.9	\$1.60

B) Dividends per Share

The Company paid dividends of \$498 million, \$0.66 per share, for the nine months ended September 30, 2012 (September 30, 2011 – \$452 million, \$0.60 per share).

The Cenovus Board of Directors declared a fourth quarter dividend of \$0.22 per share, payable on December 31, 2012, to common shareholders of record as of December 14, 2012.

8. INVENTORIES

As at	September 30, 2012	December 31, 2011
Product		
Refining and Marketing	994	1,079
Oil Sands	194	186
Conventional	1	1
Parts and Supplies	32	25
	<u>1,221</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	September 30, 2012	December 31, 2011
Assets Held for Sale		
Property, plant and equipment	-	116
Liabilities Related to Assets Held for Sale		
Decommissioning liabilities	-	54

In January 2012, the Company completed the sale of non-core natural gas assets located in Northern Alberta. A loss of \$2 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	451
Transfers to property, plant and equipment (Note 11)	(1)
Exploration expense	(68)
Divestitures	-
Change in decommissioning liabilities	7
As at September 30, 2012	<u>1,269</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 nine months ended September 30, 2012 include \$26 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2011 – \$15 million). Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the nine months ended September 30, 2012 or for the year ended December 31, 2011.

For the nine months ended September 30, 2012, \$1 million of 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 Statements of Earnings and Comprehensive Income. During the nine months ended September 30, 2012, \$68 million of previously capitalized E&E costs related primarily to the Roncott assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense. There were no amounts expensed for the nine months ended September 30, 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	1,759	31	59	134	1,983
Transfers from E&E assets (Note 10)	1	-	-	-	1
Transfers and reclassifications	-	-	(44)	-	(44)
Change in decommissioning liabilities	324	-	-	-	324
Exchange rate movements	1	-	(112)	-	(111)
Divestitures	-	-	-	-	-
As at September 30, 2012	25,943	225	3,328	710	30,206
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	1,019	13	109	35	1,176
Transfers and reclassifications	-	-	(44)	-	(44)
Impairment losses	-	-	-	-	-
Exchange rate movements	-	-	(8)	-	(8)
Divestitures	-	-	-	-	-
As at September 30, 2012	14,040	152	282	379	14,853
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 September 30, 2012	11,903	73	3,046	331	15,353

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

Additions to development and production assets include internal costs directly related to the development and construction of oil and gas properties of \$121 million for the nine months ended September 30, 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 nine months ended September 30, 2012 or for the year ended December 31, 2011.

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

As at	September 30, 2012	December 31, 2011
Development and production	41	52
Refining equipment	87	125
Other	201	112
	329	289

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 for the nine months ended September 30, 2012 or 2011.

12. LONG-TERM DEBT

As at	September 30, 2012	December 31, 2011
Canadian Dollar Denominated Debt		
Revolving term debt ¹	-	-
U.S. Dollar Denominated Debt		
Revolving term debt ¹	-	-
Unsecured notes	4,673	3,559
	<u>4,673</u>	<u>3,559</u>
Total Debt Principal	4,673	3,559
Debt Discounts and Transaction Costs	(47)	(32)
Current Portion of Long-Term Debt	-	-
	<u>4,626</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 September 30, 2012, the Company is in compliance with all of the terms of its debt agreements.

On May 24, 2012, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of \$1.5 billion. The Canadian shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at September 30, 2012, no medium term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On June 6, 2012, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US\$2.0 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and expiry dates will be determined at the date of issue. As at September 30, 2012, US\$750 million remains under this U.S. shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 17, 2012 Cenovus completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US\$1.25 billion under the Company's U.S. base shelf prospectus. The net proceeds will be used for general corporate purposes, including repayment of commercial paper indebtedness. The unsecured notes issued are as follows:

	US\$ Principal Amount	September 30, 2012
3.00% due August 15, 2022	500	492
4.45% due September 15, 2042	750	738
	<u>1,250</u>	<u>1,230</u>

In September 2012, Cenovus renegotiated its existing \$3.0 billion committed credit facility, extending the maturity date to November 30, 2016 and slightly reducing both the standby fees required to maintain the facility as well as the cost of future borrowings.

13. 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	September 30, 2012	December 31, 2011
Decommissioning Liabilities, Beginning of Year	1,777	1,399
Liabilities incurred	51	49
Liabilities settled	(48)	(56)
Liabilities divested	-	-
Transfers and reclassifications	3	(55)
Change in estimated future cash flows	7	146
Change in discount rate	273	218
Unwinding of discount on decommissioning liabilities	64	75
Foreign currency translation	(1)	1
Decommissioning Liabilities, End of Period	<u>2,126</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 4.2 percent as at September 30, 2012 (December 31, 2011 – 4.8 percent).

14. SHARE CAPITAL

A) 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.

B) Issued and Outstanding

As at	September 30, 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	<u>1,271</u>	<u>47</u>	<u>1,824</u>	<u>64</u>
Outstanding, End of Period	<u>755,770</u>	<u>3,827</u>	<u>754,499</u>	<u>3,780</u>

There were no Preferred Shares outstanding as at September 30, 2012 (December 31, 2011 – nil).

As at September 30, 2012, there were 28 million (December 31, 2011 – 30 million) common shares available for future issuance under stock option plans.

15. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended September 30, 2012

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 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 September 30, 2012	Issued	Term (years)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (\$)	Closing Share Price (\$)	Units Outstanding (thousands)
Encana Replacement TSARs held by Cenovus Employees	Prior to Arrangement	5	0.91	32.66	21.53	7,812
Cenovus Replacement TSARs held by Encana Employees	Prior to Arrangement	5	0.94	29.34	34.31	5,446
TSARs	Prior to February 17, 2010	5	0.96	29.33	34.31	6,409
TSARs	On or After February 17, 2010	7	4.45	26.72	34.31	5,095
NSRs	On or After February 24, 2011	7	6.07	37.63	34.31	14,794

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

NSRs

The weighted average unit fair value of NSRs granted during the nine months ended September 30, 2012 was \$7.68 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:

Risk Free Interest Rate	1.37%
Expected Dividend Yield	2.31%
Expected Volatility ¹	28.64%
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 September 30, 2012:

As at September 30, 2012 (thousands of units)	NSRs	Weighted Average Exercise Price (\$)
Outstanding, Beginning of Year	5,809	36.95
Granted	9,245	38.06
Exercised for common shares	(3)	35.67
Forfeited	(257)	37.60
Outstanding, End of Period	14,794	37.63
Exercisable, End of Period	1,603	37.24

The weighted average market price of Cenovus's common shares at the date of exercise during the nine months ended September 30, 2012 was \$36.91.

As at September 30, 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	14,794	6.07	37.63
	14,794	6.07	37.63

As at September 30, 2012 Range of Exercise Price (\$)	Exercisable NSRs (thousands of units)	
	NSRs	Weighted Average Exercise Price (\$)
30.00 to 39.99	1,603	37.24
	1,603	37.24

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

All amounts in \$ millions, unless otherwise indicated

For the period ended September 30, 2012

TSARs Held by Cenovus Employees

The Company has recorded a liability of \$74 million as at September 30, 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 as at September 30, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	1.27%
Expected Dividend Yield	2.53%
Expected Volatility ¹	28.41%
Cenovus's Common Share Price	\$34.31

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 September 30, 2012 was \$54 million (December 31, 2011 – \$43 million).

The following tables summarize the information related to the TSARs held by Cenovus employees as at September 30, 2012:

As at September 30, 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	(853)	(994)	(1,847)	28.39
Exercised as options for common shares	(643)	(608)	(1,251)	27.64
Forfeited	(115)	(204)	(319)	26.77
Outstanding, End of Period	<u>7,780</u>	<u>3,724</u>	<u>11,504</u>	<u>28.17</u>
Exercisable, End of Period	<u>5,415</u>	<u>3,724</u>	<u>9,139</u>	<u>28.51</u>

The weighted average market price of Cenovus's common shares at the date of exercise during the nine months ended September 30, 2012 was \$36.89.

As at September 30, 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	6,360	2,173	8,533	3.13	26.38
30.00 to 39.99	1,357	1,551	2,908	0.72	33.08
40.00 to 49.99	63	-	63	0.70	43.29
	<u>7,780</u>	<u>3,724</u>	<u>11,504</u>	<u>2.51</u>	<u>28.17</u>

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

As at September 30, 2012 Range of Exercise Price (\$)	Exercisable TSARs (thousands of units)			Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total	
20.00 to 29.99	4,130	2,173	6,303	26.34
30.00 to 39.99	1,222	1,551	2,773	33.10
40.00 to 49.99	63	-	63	43.29
	5,415	3,724	9,139	28.51

The market price of Cenovus common shares as at September 30, 2012 was \$34.31.

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 \$2 million as at September 30, 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 as at September 30, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	1.21%
Expected Dividend Yield	3.86%
Expected Volatility ¹	30.62%
Encana's Common Share Price	\$21.53

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 September 30, 2012 was \$nil (December 31, 2011 – \$nil).

The following tables summarize the information related to the Encana Replacement TSARs held by Cenovus employees as at September 30, 2012:

As at September 30, 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	(97)	(309)	(406)	30.91
Expired	(957)	(1,236)	(2,193)	29.70
Outstanding, End of Period	3,227	4,585	7,812	32.66
Exercisable, End of Period	3,214	4,585	7,799	32.67

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (unaudited)
 All amounts in \$ millions, unless otherwise indicated
 For the period ended September 30, 2012

As at September 30, 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	1,572	2,524	4,096	1.37	29.02
30.00 to 39.99	1,522	2,061	3,583	0.40	36.38
40.00 to 49.99	131	-	131	0.73	44.84
50.00 to 59.99	2	-	2	0.64	50.39
	3,227	4,585	7,812	0.91	32.66

As at September 30, 2012 Range of Exercise Price (\$)	Exercisable TSARs (thousands of units)			Weighted Average Exercise Price (\$)
	TSARs	Performance TSARs	Total	
20.00 to 29.99	1,567	2,524	4,091	29.02
30.00 to 39.99	1,514	2,061	3,575	36.39
40.00 to 49.99	131	-	131	44.84
50.00 to 59.99	2	-	2	50.39
	3,214	4,585	7,799	32.67

The market price of Encana common shares as at September 30, 2012 was \$21.53.

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.

The Company has recorded a liability of \$46 million as at September 30, 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 as at September 30, 2012 using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk Free Interest Rate	1.21%
Expected Dividend Yield	2.53%
Expected Volatility ¹	28.41%
Cenovus's Common Share Price	\$34.31

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 September 30, 2012 was \$28 million (December 31, 2011 – \$32 million).

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The following tables summarize the information related to the Cenovus Replacement TSARs held by Encana employees as at September 30, 2012:

As at September 30, 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	(1,680)	(2,099)	(3,779)	28.60
Exercised as options for common shares	(8)	(12)	(20)	26.65
Forfeited	(104)	(337)	(441)	27.45
Outstanding, End of Period	<u>2,143</u>	<u>3,303</u>	<u>5,446</u>	<u>29.34</u>
Exercisable, End of Period	<u>2,135</u>	<u>3,303</u>	<u>5,438</u>	<u>29.35</u>

The weighted average market price of Cenovus's common shares at the date of exercise during the nine months ended September 30, 2012 was \$36.84.

Outstanding TSARs (thousands of units)					
As at September 30, 2012 Range of Exercise Price (\$)	TSARs	Performance TSARs	Total	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (\$)
20.00 to 29.99	1,114	1,943	3,057	1.37	26.28
30.00 to 39.99	975	1,360	2,335	0.38	33.05
40.00 to 49.99	54	-	54	0.69	42.68
	<u>2,143</u>	<u>3,303</u>	<u>5,446</u>	<u>0.94</u>	<u>29.34</u>

Exercisable TSARs (thousands of units)					
As at September 30, 2012 Range of Exercise Price (\$)	TSARs	Performance TSARs	Total	Weighted Average Exercise Price (\$)	
20.00 to 29.99		1,106	1,943	26.27	
30.00 to 39.99		975	1,360	33.05	
40.00 to 49.99		54	54	42.68	
		<u>2,135</u>	<u>3,303</u>	<u>29.35</u>	

The market price of Cenovus common shares as at September 30, 2012 was \$34.31.

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 \$109 million as at September 30, 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 September 30, 2012. The intrinsic value of vested PSUs was \$nil as at September 30, 2012 and December 31, 2011 as PSUs are paid out upon vesting.

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The following table summarizes the information related to the PSUs held by Cenovus employees as at September 30, 2012:

As at September 30, 2012 (thousands of units)	PSUs
Outstanding, Beginning of Year	2,623
Granted	2,699
Cancelled	(132)
Units in Lieu of Dividends	81
Outstanding, End of Period	<u>5,271</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 \$37 million as at September 30, 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 September 30, 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 September 30, 2012:

As at September 30, 2012 (thousands of units)	DSUs
Outstanding, Beginning of Year	1,042
Granted to Directors	63
Granted from Annual Bonus Awards	22
Units in Lieu of Dividends	22
Exercised	(73)
Outstanding, End of Period	<u>1,076</u>

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 September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
NSRs	9	3	22	11
TSARs held by Cenovus employees	4	(25)	-	11
Encana Replacement TSARs held by Cenovus employees	-	(11)	1	(7)
PSUs	18	3	39	19
DSUs	2	(4)	4	2
	<u>33</u>	<u>(34)</u>	<u>66</u>	<u>36</u>

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16. 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 September 30,	FCCL Partnership ¹		WRB Refining LP ¹	
	2012	2011	2012	2011
Revenues	748	515	2,456	2,221
Expenses				
Purchased product	-	-	1,801	1,896
Operating, transportation and blending and realized (gain)/loss on risk management	458	304	121	92
Operating Cash Flow	290	211	534	233
Depreciation, depletion and amortization	79	55	33	20
Other expenses (income)	57	(210)	11	(13)
Net Earnings (Loss)	154	366	490	226

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 Statements of Earnings For the nine months ended September 30,	FCCL Partnership ¹		WRB Refining LP ¹	
	2012	2011	2012	2011
Revenues	2,285	1,662	7,368	6,293
Expenses				
Purchased product	-	-	5,869	5,229
Operating, transportation and blending and realized (gain)/loss on risk management	1,425	991	350	329
Operating Cash Flow	860	671	1,149	735
Depreciation, depletion and amortization	217	145	100	54
Other expenses (income)	33	(179)	7	(14)
Net Earnings (Loss)	610	705	1,042	695

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	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Cash and Cash Equivalents	352	145	200	166
Other Current Assets	782	792	1,266	1,236
Long-term Assets	7,321	6,864	3,043	3,188
Current Liabilities	420	317	584	759
Long-term Liabilities	105	83	70	73

17. 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	September 30, 2012	December 31, 2011
Long-Term Debt	4,626	3,527
Debt	4,626	3,527
Shareholders' Equity	10,064	9,406
Total Capitalization	14,690	12,933
Debt to Capitalization	31%	27%

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

As at	September 30, 2012	December 31, 2011
Debt	4,626	3,527
Net Earnings	1,377	1,478
Add (deduct):		
Finance costs	456	447
Interest income	(114)	(124)
Income tax expense	680	729
Depreciation, depletion and amortization	1,559	1,295
Exploration expense	68	-
Unrealized (gain) loss on risk management	302	(180)
Foreign exchange (gain) loss, net	(72)	26
(Gain) loss on divestiture of assets	(104)	(107)
Other (income) loss, net	(1)	4
Adjusted EBITDA ¹	4,151	3,568
Debt to Adjusted EBITDA	1.1x	1.0x

1. 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 September 30, 2012, Cenovus is in compliance with all of the terms of its debt agreements.

18. 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 September 30, 2012, the carrying value of Cenovus's long-term debt accounted for using amortized cost was \$4,626 million and the fair value was \$5,537 million (December 31, 2011 carrying value - \$3,527, fair value - \$4,316).

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at	September 30, 2012	December 31, 2011
Risk Management Assets		
Current asset	163	232
Long-term asset	31	52
	194	284
Risk Management Liabilities		
Current liability	39	54
Long-term liability	4	14
	43	68
Net Risk Management Asset (Liability)	151	216

Summary of Unrealized Risk Management Positions

As at	September 30, 2012			December 31, 2011		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	97	41	56	22	65	(43)
Natural Gas	96	1	95	247	3	244
Power	1	1	-	15	-	15
Total Fair Value	194	43	151	284	68	216

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Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	September 30, 2012	December 31, 2011
Prices actively quoted	178	226
Prices sourced from observable data or market corroboration	(27)	(10)
Total Fair Value	151	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 September 30, 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	14
WTI NYMEX Fixed Price	24,500 bbls/d	2012	\$99.47/bbl	18
Brent Fixed Price ¹	18,500 bbls/d	2013	US\$110.36/bbl	22
Brent Fixed Price ¹	18,500 bbls/d	2013	\$111.72/bbl	38
Other Fixed Price Contracts ²		2012-2014		(27)
Other Financial Positions ³				(9)
Crude Oil Fair Value Position				56
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	130 MMcf/d	2012	US\$5.96/Mcf	31
AECO Fixed Price ²	127 MMcf/d	2012	\$4.50/Mcf	18
NYMEX Fixed Price	166 MMcf/d	2013	US\$4.64/Mcf	48
Other Fixed Price Contracts ²		2012-2013		(2)
Natural Gas Fair Value Position				95
Power Purchase Contracts				
Power Fair Value Position				-

1. Brent fixed price positions consist of both Brent fixed price swaps and WTI swaps converted to Brent.

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

3. 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 September 30,	Three Months Ended		Nine Months Ended	
	2012	2011	2012	2011
REALIZED GAIN (LOSS) ¹				
Crude Oil	26	8	26	(96)
Natural Gas	65	46	200	143
Refining	6	16	18	3
Power	2	9	-	6
	99	79	244	56
UNREALIZED GAIN (LOSS) ²				
Crude Oil	(189)	353	102	418
Natural Gas	(83)	11	(144)	(38)
Refining	(11)	15	(3)	16
Power	(10)	2	(15)	26
	(293)	381	(60)	422
Gain (Loss) on Risk Management	(194)	460	184	478

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.

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Reconciliation of Unrealized Risk Management Positions

For the period ended September 30,	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	184	184	478
Unrealized foreign exchange gain (loss) on U.S. dollar contracts	(5)	-	-
Fair value of contracts realized during the period	(244)	(244)	(56)
Fair Value of Contracts, End of Period	151	(60)	422

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 September 30, 2012 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US\$10 per bbl applied to Brent & WTI hedges	(205)	205
Crude oil differential price	± US\$5 per bbl applied to differential hedges tied to production	112	(112)
Natural gas commodity price	± \$1 per mcf applied to NYMEX and AECO natural gas hedges	(84)	84
Natural gas basis price	± \$0.10 per mcf natural gas basis hedges	1	(1)
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.

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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 and are subject to normal industry credit risks. As at September 30, 2012, 92 percent (December 31, 2011 – over 92 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

As at September 30, 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 17, over the long term, 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 September 30, 2012, Cenovus had \$3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for \$1.5 billion and unused capacity of US\$750 million under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

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	2,760	-	-	-	2,760
Risk Management Liabilities	39	4	-	-	43
Long-Term Debt ¹	251	1,249	427	7,054	8,981
Partnership Contribution Payable ¹	481	962	721	-	2,164
Other ¹	-	9	4	4	17

1. Principal and interest, including current portion, if any.

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 September 30, 2012, Cenovus had US\$4,750 million in U.S. dollar debt issued from Canada (US\$3,500 million as at December 31, 2011) and US\$1,884 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 \$29 million change in foreign exchange (gain) loss as at September 30, 2012 (September 30, 2011 – \$13 million).

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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 September 30, 2012, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to \$nil (September 30, 2011 – \$nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

19. 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				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Gross Sales	13,427	4,462	4,279	4,686	16,185	4,480	3,989	4,085	3,631
Less: Royalties	309	122	65	122	489	151	131	76	131
Revenues	13,118	4,340	4,214	4,564	15,696	4,329	3,858	4,009	3,500
Operating Cash Flow									
Crude Oil and Natural Gas Liquids									
Foster Creek	678	227	223	228	780	213	194	222	151
Christina Lake	225	93	70	62	125	61	19	23	22
Pelican Lake	320	108	85	127	305	69	83	76	77
Conventional	722	227	228	267	881	246	209	218	208
Natural Gas	379	126	121	132	777	188	200	197	192
Other Upstream Operations	4	2	-	2	13	4	2	3	4
	2,328	783	727	818	2,881	781	707	739	654
Refining and Marketing	1,145	527	351	267	981	238	238	325	180
Operating Cash Flow ⁽¹⁾	3,473	1,310	1,078	1,085	3,862	1,019	945	1,064	834
Cash Flow Information									
Cash from Operating Activities	2,662	1,029	968	665	3,273	952	921	769	631
Deduct (Add back):									
Net change in other assets and liabilities	(71)	(19)	(20)	(32)	(82)	(20)	(17)	(16)	(29)
Net change in non-cash working capital	(213)	(69)	63	(207)	79	121	145	(154)	(33)
Cash Flow ⁽²⁾	2,946	1,117	925	904	3,276	851	793	939	693
Per share - Basic	3.90	1.48	1.22	1.20	4.34	1.13	1.05	1.25	0.92
Per share - Diluted	3.88	1.47	1.22	1.19	4.32	1.12	1.05	1.24	0.91
Operating Earnings ⁽³⁾	1,055	432	283	340	1,239	332	303	395	209
Per share - Diluted	1.39	0.57	0.37	0.45	1.64	0.44	0.40	0.52	0.28
Net Earnings	1,111	289	396	426	1,478	266	510	655	47
Per share - Basic	1.47	0.38	0.52	0.56	1.96	0.35	0.68	0.87	0.06
Per share - Diluted	1.46	0.38	0.52	0.56	1.95	0.35	0.67	0.86	0.06
Effective Tax Rates using									
Net Earnings	34.8%				33.0%				
Operating Earnings, excluding divestitures	36.6%				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	0.998	1.005	0.990	0.999	1.012	0.978	1.020	1.033	1.015
Period end	1.017	1.017	0.981	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)}	31%	27%
Debt to Adjusted EBITDA ^{(5), (6)}	1.1x	1.0x
Return on Capital Employed ⁽⁷⁾	11%	13%
Return on Common Equity ⁽⁸⁾	14%	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.

Financial Statistics (continued)

Common Share Information

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding (millions)									
Period end	755.8	755.8	755.7	755.6	754.5	754.5	754.3	754.1	753.9
Average - Basic	755.5	755.7	755.7	755.1	754.0	754.4	754.3	754.1	753.2
Average - Diluted	758.5	758.0	757.9	759.5	757.7	757.1	757.8	758.0	758.1
Price Range (\$ per share)									
TSX - C\$									
High	39.64	36.25	36.68	39.64	38.98	37.11	38.38	38.98	38.90
Low	30.09	30.37	30.09	33.24	28.85	28.85	29.87	31.73	31.15
Close	34.31	34.31	32.37	35.90	33.83	33.83	32.27	36.40	38.30
NYSE - US\$									
High	39.81	37.31	37.26	39.81	40.73	37.35	40.61	40.73	40.06
Low	28.83	30.20	28.83	32.45	27.15	27.15	29.02	32.48	31.11
Close	34.85	34.85	31.80	35.94	33.20	33.20	30.71	37.66	39.38
Dividends Paid (\$ per share)	\$ 0.66	\$ 0.22	\$ 0.22	\$ 0.22	\$ 0.80	\$ 0.20	\$ 0.20	\$ 0.20	\$ 0.20
Share Volume Traded (millions)	522.6	152.6	192.6	177.4	873.7	213.3	239.8	215.9	204.7

Net Capital Investment (\$ millions)

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment									
Oil Sands									
Foster Creek	527	199	169	159	429	139	110	77	103
Christina Lake	412	147	138	127	472	126	117	121	108
Total	939	346	307	286	901	265	227	198	211
Pelican Lake	371	128	104	139	317	132	70	31	84
Other Oil Sands	296	42	43	211	197	68	9	11	109
	1,606	516	454	636	1,415	465	306	240	404
Conventional	591	231	129	231	788	330	193	89	176
Refining and Marketing	60	38	24	(2)	393	73	101	117	102
Corporate	133	45	53	35	127	35	31	30	31
Capital Investment	2,390	830	660	900	2,723	903	631	476	713
Acquisitions	44	8	28	8	71	49	1	2	19
Divestitures	(65)	-	1	(66)	(173)	(164)	-	(5)	(4)
Net Acquisition and Divestiture Activity	(21)	8	29	(58)	(102)	(115)	1	(3)	15
Net Capital Investment	2,369	838	689	842	2,621	788	632	473	728

Operating Statistics - Before Royalties

Upstream Production Volumes

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)									
Oil Sands - Heavy Oil									
Foster Creek	57,421	63,245	51,740	57,214	54,868	55,045	56,322	50,373	57,744
Christina Lake	28,577	32,380	28,577	24,733	11,665	19,531	10,067	7,880	9,084
Total	85,998	95,625	80,317	81,947	66,533	74,576	66,389	58,253	66,828
Pelican Lake	22,231	23,539	22,410	20,730	20,424	20,558	20,363	19,427	21,360
	108,229	119,164	102,727	102,677	86,957	95,134	86,752	77,680	88,188
Conventional Liquids									
Heavy Oil	15,938	15,492	15,703	16,624	15,657	15,512	15,305	15,378	16,447
Light and Medium Oil	36,083	35,695	36,149	36,411	30,524	32,530	30,399	27,617	31,539
Natural Gas Liquids ⁽¹⁾	1,041	999	987	1,138	1,101	1,097	1,040	1,087	1,181
Total Crude Oil and Natural Gas Liquids	161,291	171,350	155,566	156,850	134,239	144,273	133,496	121,762	137,355
Natural Gas (MMcf/d)									
Oil Sands									
Conventional ⁽²⁾	33	27	33	41	37	38	39	37	32
Total Natural Gas	569	550	563	595	619	622	617	617	620
	602	577	596	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 September YTD production approximately 3%.

Average Royalty Rates

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

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands									
Foster Creek	13.0%	19.1%	4.6%	13.9%	16.8%	21.7%	20.6%	3.3%	21.2%
Christina Lake	6.4%	5.3%	7.2%	7.0%	5.2%	4.7%	5.7%	6.3%	4.8%
Pelican Lake	5.1%	6.6%	4.2%	4.5%	11.5%	9.1%	12.7%	9.7%	13.9%
Conventional									
Weyburn	21.6%	19.8%	21.4%	23.3%	24.1%	24.8%	23.9%	23.6%	24.3%
Other	7.3%	6.6%	6.8%	8.3%	8.3%	8.1%	9.0%	8.5%	7.6%
Natural Gas Liquids	2.0%	2.5%	1.7%	1.7%	1.7%	1.8%	1.4%	2.3%	1.3%
Natural Gas	1.3%	0.8%	0.4%	2.5%	1.7%	1.9%	1.5%	1.2%	2.3%

Operating Statistics - Before Royalties (continued)

Refining

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations ⁽¹⁾									
Crude oil capacity (Mbbbls/d)	452	452	452	452	452	452	452	452	452
Crude oil runs (Mbbbls/d)	446	442	451	445	401	424	413	406	362
Crude utilization	99%	98%	100%	98%	89%	94%	91%	90%	80%
Refined products (Mbbbls/d)	467	463	473	465	419	442	426	422	383

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

Selected Average Benchmark Prices

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices (US\$/bbl)									
Brent Futures ("ICE")	112.20	109.42	108.76	118.45	110.91	109.02	112.09	116.99	105.52
West Texas Intermediate ("WTI")	96.16	92.20	93.35	103.03	95.11	94.06	89.54	102.34	94.60
Average Differential Brent Futures (ICE)-WTI	16.04	17.22	15.41	15.42	15.80	14.96	22.55	14.65	10.92
Western Canadian Select ("WCS")	74.16	70.48	70.48	81.61	77.96	83.58	71.92	84.70	71.74
Differential - WTI-WCS	22.00	21.72	22.87	21.42	17.15	10.48	17.62	17.64	22.86
Condensate - (C5 @ Edmonton)	101.83	96.12	99.32	110.16	105.34	108.74	101.48	112.33	98.90
Differential - WTI-Condensate (premium)/discount	(5.67)	(3.92)	(5.97)	(7.13)	(10.23)	(14.68)	(11.94)	(9.99)	(4.30)
Refining Margins 3-2-1 Crack Spreads ⁽²⁾ (US\$/bbl)									
Chicago	27.61	35.64	28.20	19.00	24.55	19.23	33.35	29.00	16.62
Midwest Combined (Group 3)	28.59	35.99	28.28	21.50	25.26	20.75	34.04	27.19	19.04
Natural Gas Prices									
AECO (\$/GJ)	2.07	2.08	1.74	2.39	3.48	3.29	3.53	3.54	3.58
NYMEX (US\$/MMBtu)	2.59	2.81	2.22	2.74	4.04	3.55	4.19	4.31	4.11
Differential - NYMEX/AECO (US\$/MMBtu)	0.41	0.61	0.39	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 regular unleaded gasoline and one barrel of ultra-low sulphur diesel, and reflects the current month WTI price as the crude oil feedstock price.

Per-unit Results

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

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek (\$/bbl) ⁽³⁾									
Price	66.18	63.95	63.83	70.71	67.38	75.96	62.68	72.23	59.50
Royalties	8.35	11.79	2.85	9.54	10.82	15.81	12.38	2.30	11.92
Transportation and blending	2.24	2.38	1.91	2.38	3.04	3.20	2.73	2.82	3.41
Operating	12.26	11.50	12.49	12.85	11.34	11.31	11.11	11.57	11.40
Netback	43.33	38.28	46.58	45.94	42.18	45.64	36.46	55.54	32.77
Heavy Oil - Christina Lake (\$/bbl) ⁽³⁾									
Price	49.99	52.91	44.57	52.58	61.86	66.69	54.52	67.06	54.67
Royalties	2.94	2.61	2.90	3.37	3.03	2.97	2.87	3.98	2.44
Transportation and blending	4.19	4.00	4.12	4.51	3.53	2.98	4.54	3.51	3.69
Operating	13.76	13.59	12.52	15.33	20.20	17.96	23.01	23.41	19.09
Netback	29.10	32.71	25.03	29.37	35.10	42.78	24.10	36.16	29.45
Heavy Oil - Pelican Lake (\$/bbl) ⁽³⁾									
Price	70.82	66.75	66.42	78.50	73.07	88.67	66.76	78.26	64.66
Royalties	3.51	4.34	2.68	3.37	7.91	6.98	8.23	7.40	8.63
Transportation and blending	2.45	1.09	3.54	2.88	4.14	12.19	1.87	2.02	2.44
Operating	17.04	17.47	17.71	16.05	14.86	16.49	14.31	13.40	15.35
Netback	47.82	43.85	42.49	56.20	46.16	53.01	42.35	55.44	38.24
Heavy Oil - Oil Sands (\$/bbl) ⁽³⁾									
Price	63.07	61.71	59.00	68.36	67.99	76.39	62.93	73.02	60.35
Royalties	5.91	7.85	2.83	6.66	9.17	11.72	10.46	3.65	10.08
Transportation and blending	2.78	2.52	2.87	2.99	3.36	4.75	2.68	2.71	3.18
Operating	13.68	13.29	13.61	14.18	13.27	13.54	13.02	13.27	13.23
Netback	40.70	38.05	39.69	44.53	42.19	46.38	36.77	53.39	33.86
Heavy Oil - Conventional (\$/bbl) ⁽³⁾									
Price	72.53	68.04	67.70	80.64	74.17	81.49	67.96	78.47	69.17
Royalties	10.54	8.81	9.36	13.06	10.75	11.85	11.33	10.98	9.04
Transportation and blending	2.11	2.31	2.26	1.81	1.27	1.34	1.80	0.91	1.05
Operating	16.43	16.48	15.07	17.57	13.77	16.34	12.40	13.66	12.78
Production and mineral taxes	0.21	0.27	0.25	0.14	0.32	0.34	0.17	0.22	0.51
Netback	43.24	40.17	40.76	48.06	48.06	51.62	42.26	52.70	45.79
Total Heavy Oil (\$/bbl) ⁽³⁾									
Price	64.28	62.45	60.13	70.08	68.98	77.16	63.69	73.98	61.80
Royalties	6.50	7.96	3.68	7.56	9.42	11.74	10.59	4.93	9.91
Transportation and blending	2.70	2.50	2.79	2.82	3.02	4.23	2.55	2.40	2.83
Operating	14.04	13.66	13.80	14.65	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	0.03	0.03	0.03	0.02	0.05	0.05	0.03	0.04	0.08
Netback	41.01	38.30	39.83	45.03	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil (\$/bbl)									
Price	80.24	76.06	76.16	88.45	85.40	90.90	79.57	94.30	77.39
Royalties	8.49	7.53	7.98	9.94	11.54	12.12	10.74	12.82	10.58
Transportation and blending	2.73	2.36	3.02	2.83	2.00	1.99	1.90	2.22	1.92
Operating	15.48	16.27	14.76	15.36	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	2.42	2.35	2.34	2.57	2.27	2.63	2.40	2.77	1.32
Netback	51.12	47.55	48.06	57.75	55.21	59.04	50.16	63.53	48.71

⁽³⁾ 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 - \$43.10/bbl; Christina Lake - \$47.09/bbl; Pelican Lake - \$15.97/bbl; Heavy Oil - Oil Sands - \$38.16/bbl; Heavy Oil - Conventional - \$13.69/bbl and Total Heavy Oil - \$35.02/bbl.

Operating Statistics - Before Royalties (continued)

Per-unit Results

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

	2012				2011				
	Year to Date	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil (\$/bbl)									
Price	67.87	65.37	63.91	74.22	72.80	80.49	67.37	78.71	65.32
Royalties	6.95	7.87	4.69	8.10	9.92	11.83	10.62	6.77	10.06
Transportation and blending	2.70	2.47	2.84	2.83	2.78	3.69	2.40	2.35	2.63
Operating	14.36	14.22	14.03	14.81	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	0.57	0.53	0.58	0.59	0.57	0.67	0.58	0.67	0.36
Netback	43.29	40.28	41.77	47.89	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids (\$/bbl)									
Price	70.71	61.53	65.52	83.36	76.84	82.26	74.38	80.32	70.67
Royalties	1.38	1.55	1.13	1.45	1.34	1.51	1.06	1.87	0.93
Netback	69.33	59.98	64.39	81.91	75.50	80.75	73.32	78.45	69.74
Total Liquids (\$/bbl)									
Price	67.89	65.35	63.92	74.28	72.84	80.50	67.43	78.72	65.37
Royalties	6.91	7.83	4.67	8.05	9.84	11.75	10.55	6.72	9.98
Transportation and blending	2.69	2.45	2.82	2.81	2.76	3.66	2.38	2.33	2.60
Operating	14.27	14.14	13.93	14.71	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	0.56	0.53	0.57	0.59	0.56	0.67	0.57	0.67	0.36
Netback	43.46	40.40	41.93	48.12	46.21	50.29	40.77	55.87	39.00
Total Natural Gas (\$/Mcf)									
Price	2.25	2.30	1.92	2.50	3.65	3.35	3.72	3.71	3.82
Royalties	0.03	0.02	0.01	0.06	0.06	0.06	0.05	0.04	0.08
Transportation and blending	0.10	0.08	0.08	0.13	0.15	0.14	0.15	0.14	0.17
Operating	1.05	1.08	0.98	1.08	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	0.02	0.02	0.02	0.02	0.04	0.01	0.03	0.05	0.06
Netback	1.05	1.10	0.83	1.21	2.30	1.92	2.50	2.50	2.32
Total (\$/BOE)⁽²⁾									
Price	46.98	46.61	43.25	50.84	49.75	53.48	46.97	51.81	46.83
Royalties	4.32	5.02	2.84	5.00	5.55	6.65	5.91	3.64	5.85
Transportation and blending	1.88	1.74	1.90	2.00	1.91	2.39	1.70	1.61	1.92
Operating ⁽¹⁾	11.20	11.35	10.75	11.46	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	0.40	0.38	0.40	0.40	0.41	0.40	0.39	0.49	0.36
Netback	29.18	28.12	27.36	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 \$0.20/BOE (2011 - \$0.12/BOE).

Impact of realized gain (loss) on risk management

Liquids (\$/bbl)	0.66	2.02	1.64	(1.67)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas (\$/Mcf)	1.21	1.24	1.39	1.03	0.87	1.10	0.76	0.74	0.89
Total (\$/BOE) ⁽²⁾	3.21	3.98	4.27	1.44	0.86	1.22	2.49	(1.25)	0.83

⁽²⁾ 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", "positioned" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology including technology and procedures to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

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

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

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

NON-GAAP MEASURES

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

ADDITIONAL INFORMATION

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

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

ABBREVIATIONS

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

Oil and Natural Gas Liquids

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

Natural Gas

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

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