MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED SEPTEMBER 30, 2013

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., ("we", "our", "Cenovus", or the "Company") dated October 23, 2013, should be read in conjunction with our September 30, 2013 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2012 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2012 MD&A ("annual MD&A"). This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&A is approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Basis of Presentation

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 have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA"), 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 order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On September 30, 2013, we had a market capitalization of approximately $23 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs production (collectively, "crude oil") for the nine months ended September 30, 2013, was in excess of 176,000 barrels per day, our average natural gas production was 535 MMcf per day and our refinery operations processed an average of 440,000 gross barrels per day of crude oil feedstock into an average of 461,000 gross barrels per day of refined product.

Our Strategy

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

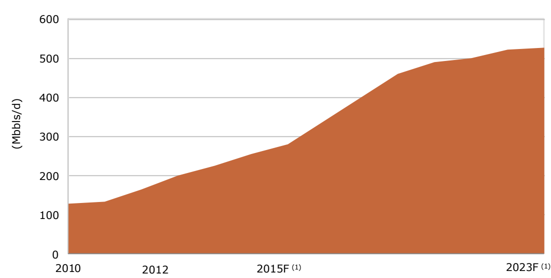
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 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 our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023. We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows Lake, Telephone Lake and our conventional tight oil opportunities. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 350-450 gross stratigraphic test wells each year for the next five years.

Total Crude Oil Production, net to Cenovus



(1) Expected net production.

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Ownership Interest (percent)	Nine Months Ended September 30, 2013 Net Production Volumes (bbls/d)	Nine Months Ended September 30, 2013 Gross Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects				
Foster Creek	50	53,450	106,900	310,000
Christina Lake	50	45,211	90,422	310,000
Narrows Lake	50	-	-	130,000
Emerging Projects				
Telephone Lake	100	-	-	300,000
Grand Rapids	100	-	-	180,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca region of northeastern Alberta.

Foster Creek is producing from phases A through E. Expansion work is underway at phases F, G and H with added production capacity from phase F expected in the third quarter of 2014 and phases G and H in 2015 and 2016, respectively. In the first quarter of 2013, we submitted a joint application and environmental impact assessment ("EIA") for Foster Creek phase J, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the first quarter of 2015.

Christina Lake is producing from phases A through E. Our phase E expansion commenced steam injection in June 2013 and first production was achieved in mid-July 2013. Expansion work is currently underway for phases F, including cogeneration, and G with added production capacity expected in 2016 and 2017, respectively. In the first quarter of 2013, we submitted an EIA for Christina Lake phase H, a 50,000 barrel per day phase and we anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval for phase A in December 2012. Construction of the phase A plant commenced in August 2013 and we anticipate first production in 2017.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project, located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012. The pilot is expected to be completed by the end of October 2013. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in the second quarter of 2014. At our Grand Rapids project, located within the Greater Pelican region, a SAGD pilot project is underway. In December 2011, we filed a joint application and EIA for a 180,000 barrel per day commercial SAGD operation. We anticipate receiving regulatory approval in the fourth quarter of 2013.

Also located within the Athabasca region is our wholly owned Pelican Lake property. While this property produces conventional heavy oil using polymer flood technology, it's managed within our Oil Sands segment. For the nine months ended September 30, 2013, our production averaged 24,162 barrels per day.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations and provides cash flows to help fund our growth opportunities.

($ millions)	Nine Months Ended September 30, 2013 Crude Oil [1]	Natural Gas
Operating Cash Flow	**771**	**314**
Capital Investment	**493**	**17**
Operating Cash Flow net of Related Capital Investment	**278**	**297**

(1) Includes NGLs.

We have established conventional crude oil and natural gas producing assets and developing tight oil assets in Alberta. We also inject carbon dioxide to enhance oil recovery at our Weyburn operations in Saskatchewan.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company.

	Ownership Interest (percent)	Current Nameplate Capacity (Mbbls/d)
Wood River	**50**	**311**
Borger	**50**	**146**

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to mitigate volatility associated with North American commodity price movements. This segment also includes the marketing of third party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	Nine Months Ended September 30, 2013
Operating Cash Flow	**985**
Capital Investment	**70**
Operating Cash Flow net of Related Capital Investment	**915**

Technology and Environment

Technology development plays a key role in all aspects of our business. We advance technologies with the goal of improving the amount of crude oil we can access and extract from the ground while reducing the amount of water, natural gas and electricity consumed in our operations and minimizing environmental disturbance. The Cenovus culture fosters new ideas and new approaches and has a track record of developing innovative solutions that unlock challenging crude oil resources, potentially reducing costs and building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. The Board of Directors approved a dividend increase of 10 percent to $0.242 per share for the first three quarters of 2013 compared to the same periods in 2012. The annualized dividend in 2012 was 10 percent higher than in 2011.

Net Asset Value

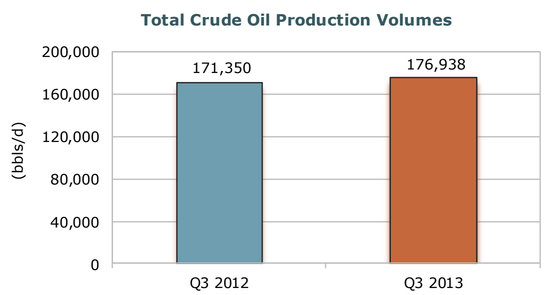
We measure our success in a number of ways with a key measure being growth in net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

The third quarter of 2013 continued to reflect the strength of our integrated approach. Overall, the integration of our business and growing crude oil production helped to mitigate the declines in our Operating Cash Flow from refining for the quarter. Upstream Operating Cash Flow increased 29 percent due to higher crude oil and natural gas prices as well as increased crude oil production. Crude oil sales prices increased mainly due to the narrowing of the West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differential. While contributing to higher upstream Operating Cash Flow, the narrowing WTI-WCS differential increased the cost of refinery crude oil feedstock which, along with sharp declines in market crack spreads, resulted in lower Operating Cash Flow from our refining operations.

Operational Results for the Third Quarter of 2013 as Compared to the Third Quarter of 2012

In the third quarter, crude oil production from our Oil Sands segment averaged 126,650 barrels per day, an increase of six percent, due primarily to growing production at Christina Lake. Average production at Christina Lake for the quarter was 52,732 barrels per day, a 63 percent increase, as phase D reached full capacity and phase E, our tenth expansion phase, started to produce in mid-July 2013. We expect the ramp-up of phase E will take six to nine months overall, similar to phases C and D, with production capacity expected to reach 138,000 barrels per day gross early in 2014.



Within our Conventional segment, crude oil production averaged 50,288 barrels per day, a decline of 1,898 barrels per day. Strong horizontal well performance from our current drilling program offset declines in production due to the sale of our Shaunavon asset in July 2013. Prior to closing the sale, our Shaunavon asset was producing an average of approximately 3,600 barrels per day in the second quarter of 2013.

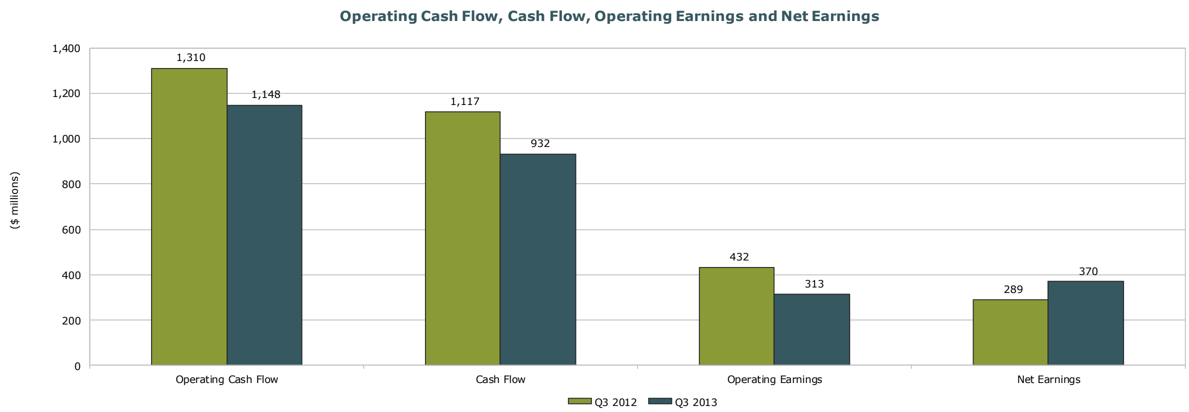
Our refining operations processed an average of 464,000 (2012 – 442,000) gross barrels per day of crude oil, of which 240,000 gross barrels per day was heavy crude oil (2012 – 210,000). We produced 487,000 gross barrels per day of refined products, an increase of about 24,000 gross barrels per day, or five percent, as refined product output in the same period last year was impacted by minor refinery outages.

Other significant operational results in the third quarter compared to 2012 include:

- Foster Creek production averaging 49,092 barrels per day, a decrease of 22 percent, resulting from a number of production matters which are discussed in the Reportable Segments section under Oil Sands;
- Pelican Lake production averaging 24,826 barrels per day, an increase of five percent resulting from additional infill wells coming on-stream throughout 2012 and 2013 as well as increased response from the polymer flood program;
- Receiving regulatory approval for an optimization program at Christina Lake phases C, D and E which is expected to add 22,000 barrels per day of gross capacity in 2015;

- The closing of the Shaunavon asset disposition for proceeds of approximately $240 million;
- Managing our natural gas production, which declined nine percent to an average of 523 MMcf per day due to expected natural declines; and
- Increasing our access to new sales markets with approximately 4,100 barrels per day of conventional crude oil transported by rail to the East Coast and the U.S.

Financial Results for the Third Quarter of 2013 as Compared to the Third Quarter of 2012

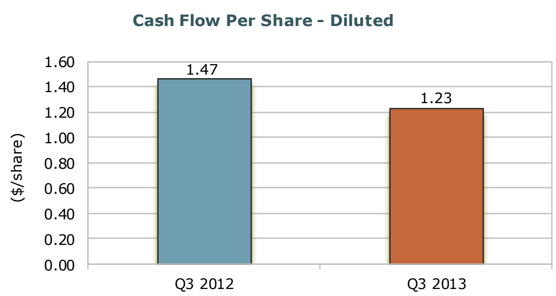


For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2012 annual MD&A.

Upstream operations benefited from higher crude oil and natural gas prices and production increases at Christina Lake. Crude oil sales prices increased 32 percent mainly due to the narrowing of the WTI-WCS differential by 20 percent, which averaged US$17.48 per barrel for the quarter (2012 – US$21.72 per barrel). Our refining operations reflected lower Operating Cash Flow primarily as a result of lower market crack spreads and higher feedstock costs consistent with the narrowing of the WTI-WCS differential and increases in costs associated with renewable identification numbers ("RINs"). The Chicago 3-2-1 and the Group 3 market crack spreads decreased by US$19.45 per barrel and US$18.64 per barrel, respectively.

Cash Flow decreased 17 percent to $932 million, primarily related to a decrease in Refining and Marketing Operating Cash Flow and realized risk management losses as compared to gains in 2012, partially offset by higher Operating Cash Flow from our upstream operations.

In August, we completed a public offering in the U.S. of US$800 million of senior unsecured notes. The net proceeds from the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014.



We paid a third quarter dividend of $0.242 per share (2012 – $0.22 per share), an increase of 10 percent over 2012, demonstrating our continuing commitment to pay a strong and sustainable dividend as part of delivering total shareholder return.

Other financial highlights for the third quarter compared to 2012 include:

Revenues

Revenues of $5,075 million, increasing $735 million or 17 percent, primarily a result of:

- Our crude oil average sales price (excluding financial hedging) increasing 32 percent to $86.28 per barrel;
- An increase in refining revenues primarily as a result of higher refined product output;
- Higher marketing revenues from third party sales undertaken to provide operational flexibility;
- A rise in condensate prices and volumes; and
- Higher crude oil production volumes.

Operating Cash Flow

Operating Cash Flow of $1,148 million, decreasing $162 million or 12 percent due to:

- Operating Cash Flow from our Refining and Marketing segment decreasing by $390 million due to a sharp decline in market crack spreads as a result of increases in refinery crude oil feedstock costs from higher commodity prices, narrowing crude oil discounts and increases in the cost of RINs. These factors were partially offset by higher refined product output; and

- Upstream realized risk management losses before tax of $12 million as compared to a gain of $99 million in 2012.

Partially offset by:

- An increase in upstream Operating Cash Flow as a result of higher average crude oil and natural gas sales prices and growing crude oil production volumes.

Operating Earnings

Operating Earnings were $313 million, a 28 percent decrease, due to lower cash flow as discussed above and higher depreciation, depletion and amortization ("DD&A"), partially offset by lower deferred income tax expense, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, and a realized foreign exchange gain of $33 million on the early redemption of debt.

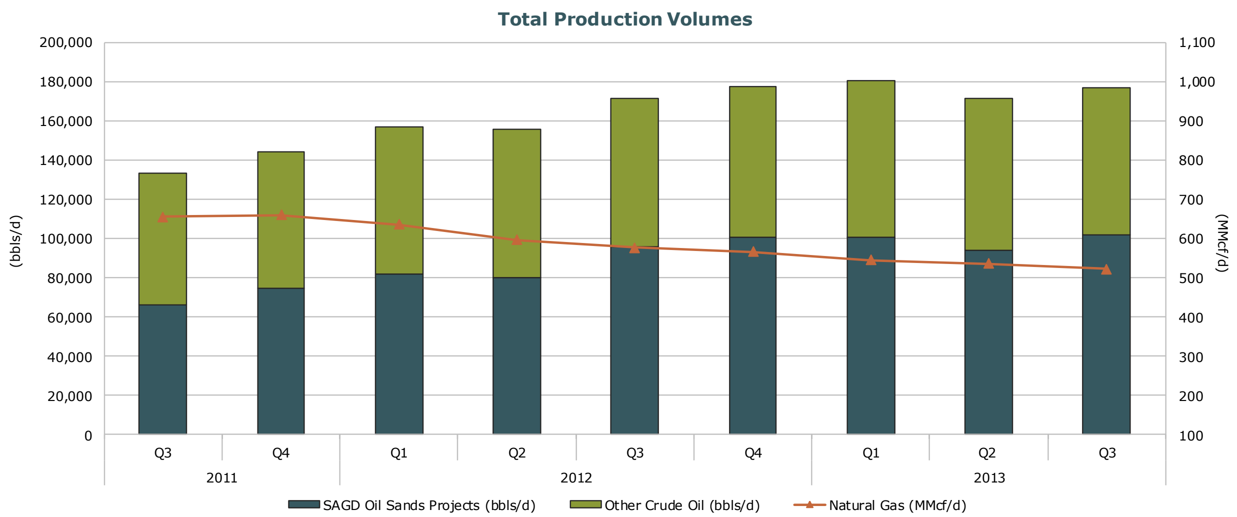
Net Earnings

Net earnings increased 28 percent to $370 million primarily due to unrealized risk management gains compared to losses in 2012.

Capital Investment

Capital investment of $743 million, decreasing from 2012 by 10 percent, primarily due to declines in our Corporate and Refining and Marketing segments, in addition to declines in our Conventional segment with reduced capital investment at our Shaunavon property. Within our oil sands operations there was a decrease at Pelican Lake, as the rate at which we are expanding the polymer flood has slowed to better match our production growth, and at Telephone Lake, as increases in spending related to the dewatering pilot were offset with the recognition of scientific research and development credits. Declines in capital investment were partially offset by increases at Foster Creek and Christina Lake, with continued focus on the development of our expansion phases, and at Narrows Lake, with construction commencing on phase A in the quarter.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended September 30, 2013	Percent Change	2012	Nine Months Ended September 30, 2013	Percent Change	2012
Oil Sands						
Foster Creek	**49,092**	**(22)%**	63,245	**53,450**	**(7)%**	57,421
Christina Lake	**52,732**	**63%**	32,380	**45,211**	**58%**	28,577
Pelican Lake	**24,826**	**5%**	23,539	**24,162**	**9%**	22,231
Conventional						
Heavy Oil	**15,507**	**-%**	15,492	**16,163**	**1%**	15,938
Light and Medium Oil	**33,651**	**(6)%**	35,695	**36,081**	**-%**	36,083
NGLs [(1)]	**1,130**	**13%**	999	**1,018**	**(2)%**	1,041
Total Crude Oil Production	**176,938**	**3%**	171,350	**176,085**	**9%**	161,291

(1) NGLs include condensate volumes.

Our crude oil production increased for the three and nine months ended September 30, 2013, primarily from higher production at Christina Lake. Production from Christina Lake phase D, which started in the third quarter of 2012, reached full capacity in the first quarter of 2013 and first production was achieved at phase E in mid-July 2013.

For the three months ended September 30, 2013, Foster Creek production averaged 49,092 barrels per day, a 22 percent decrease from 2012 due to a variety of factors. In the third quarter of 2012, Foster Creek production averaged 63,245 barrels per day (126,490 barrels per day, gross), exceeding plant capacity. In the fourth quarter of 2012, we made a decision to defer some routine workover activity until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers. In 2013, we have been catching up on routine well maintenance. These factors, along with the commencement of a planned turnaround in the third quarter of 2013 which decreased production by approximately 4,400 barrels per day and minor treating issues, contributed to lower production compared to the prior year.

Pelican Lake production increased due to additional infill wells coming on-stream throughout 2012 and 2013 and increased response from our polymer flood program.

Our crude oil production from the Conventional segment during the third quarter declined slightly and remained flat year-to-date as better horizontal well performance from our current drilling program was offset by the divestiture of our Shaunavon asset. Prior to closing the sale, our Shaunavon asset was producing an average of approximately 3,600 barrels per day in the second quarter of 2013 and 4,200 barrels per day year-to-date (year-to-date 2012 – 4,265 barrels per day).

Natural Gas Production Volumes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(MMcf per day)	**2013**	2012	**2013**	2012
Conventional	**498**	550	**512**	569
Oil Sands	**25**	27	**23**	33
	523	577	**535**	602

In the low commodity price environment, management of our natural gas spending resulted in production declines during the three and nine months ended September 30, 2013, in line with our decision to focus on high rate of return projects and direct capital investment to our crude oil properties.

Operating Netbacks

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		**2013**		2012	
	Crude Oil (1) ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil (1) ($/bbl)	Natural Gas ($/Mcf)	**Crude Oil (1)** ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil (1) ($/bbl)	Natural Gas ($/Mcf)
Price (2)	**86.28**	**2.83**	65.35	2.30	**69.91**	**3.20**	67.89	2.25
Royalties	**7.40**	**0.05**	7.83	0.02	**5.28**	**0.05**	6.91	0.03
Transportation and Blending (2)	**3.61**	**0.10**	2.45	0.08	**3.00**	**0.11**	2.69	0.10
Operating Expenses	**15.29**	**1.13**	14.14	1.08	**15.88**	**1.14**	14.27	1.05
Production and Mineral Taxes	**0.59**	**0.03**	0.53	0.02	**0.58**	**0.02**	0.56	0.02
Netback Excluding Realized Risk Management	**59.39**	**1.52**	40.40	1.10	**45.17**	**1.88**	43.46	1.05
Realized Risk Management Gain (Loss)	**(2.02)**	**0.38**	2.02	1.24	**0.45**	**0.31**	0.66	1.21
Netback Including Realized Risk Management	**57.37**	**1.90**	42.42	2.34	**45.62**	**2.19**	44.12	2.26

(1) *Includes NGLs.*
(2) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for the three months ended September 30, 2013 was $25.16 per barrel (2012 – $23.06 per barrel) and $28.05 per barrel (2012 – $26.96 per barrel) for the nine months ended September 30, 2013.*

In the three months ended September 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $18.99 per barrel from 2012 primarily due to higher sales prices, consistent with increased benchmark prices with the average WTI price increasing US$13.61 per barrel and the WTI-WCS differential narrowing US$4.24 per barrel, and lower royalties, partially offset by increased transportation and blending and operating costs.

For the nine months ended September 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, rose $1.71 per barrel from 2012 primarily due to higher sales prices and lower royalties, partially offset by higher operating costs. Sales price increases were consistent with increases in benchmark prices with the average WCS price increasing US$1.18 per barrel, despite a widening WTI-WCS differential as a result of a larger increase in the WTI price as compared to WCS.

Our average natural gas netback, excluding realized risk management gains and losses, increased $0.42 and $0.83 per Mcf in the third quarter and year-to-date, respectively. This was predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining [(1)]

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	**Percent Change**	2012	**2013**	**Percent Change**	2012
Crude Oil Runs (Mbbls/d)	**464**	**5%**	442	**440**	**(1)%**	446
Heavy Crude Oil	**240**	**14%**	210	**223**	**5%**	213
Crude Utilization (percent)	**101**	**3%**	98	**96**	**(3)%**	99
Refined Product (Mbbls/d)	**487**	**5%**	463	**461**	**(1)%**	467

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

Crude oil runs, including heavy crude oil, crude utilization and refined product output increased during the three months ended September 30, 2013 as a result of both plants operating in the quarter with minimal disruptions. Year-to-date, there was a reduction in crude oil runs, crude utilization and refined product output primarily as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter of 2013. Despite these decreases, our heavy crude oil processed increased five percent, reflecting our ability to process a greater proportion of heavy oil feedstock and the optimization of our total crude input slate.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, price differentials, 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 rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [(1)]

	Nine Months Ended September 30,				
	2013	2012	**Q3 2013**	Q2 2013	Q3 2012
Crude Oil Prices (US$/bbl)					
Brent Futures					
Average	**108.49**	112.20	**109.65**	103.35	109.42
End of Period	**108.37**	112.39	**108.37**	102.16	112.39
WTI					
Average	**98.20**	96.16	**105.81**	94.17	92.20
End of Period	**102.33**	92.19	**102.33**	96.56	92.19
Average Differential Brent-WTI	**10.29**	16.04	**3.84**	9.18	17.22
WCS					
Average	**75.34**	74.16	**88.33**	75.01	70.48
End of Period	**70.39**	82.26	**70.39**	82.16	82.26
Average Differential WTI-WCS	**22.86**	22.00	**17.48**	19.16	21.72
Condensate (C5 @ Edmonton) Average	**104.24**	101.83	**103.79**	101.45	96.12
Average Differential WTI-Condensate (Premium)/Discount	**(6.04)**	(5.67)	**2.02**	(7.28)	(3.92)
Refining Margin 3-2-1 Average Market Crack Spreads (US$/bbl)					
Chicago	**24.93**	27.61	**16.19**	31.06	35.64
Midwest Combined ("Group 3")	**24.17**	28.59	**17.35**	27.24	35.99
Natural Gas Average Prices					
AECO (C$/GJ)	**3.00**	2.07	**2.67**	3.40	2.08
NYMEX (US$/MMBtu)	**3.67**	2.59	**3.58**	4.09	2.81
Basis Differential NYMEX-AECO (US$/MMBtu)	**0.57**	0.41	**0.89**	0.56	0.61
Foreign Exchange Rate (US$/C$1)					
Average	**0.977**	0.998	**0.963**	0.977	1.005

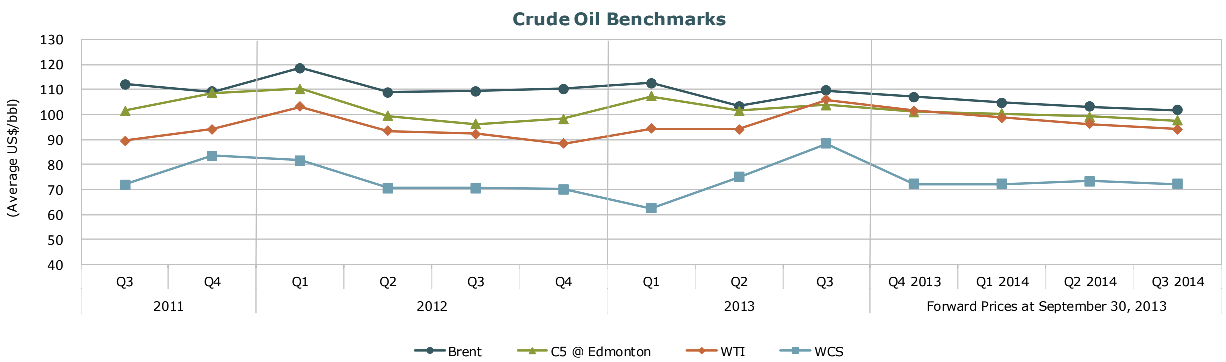
(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.

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. The average price of Brent crude oil increased by US$0.23 per barrel for the third quarter, compared to 2012, due to increased global supply outages with the largest contributor being labour and political unrest in Libya and fear of further supply outages arising from an escalation of events in the Syrian conflict. Year-to-date, there was a US$3.71 per barrel decline in the average price of Brent crude oil due to concerns over the pace of growth of the Chinese economy this spring while 2012 prices increased as a result of the Iranian nuclear situation and associated sanctions.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average price of WTI increased by US$13.61 per barrel and US$2.04 per barrel for the three and nine months ended September 30, 2013, respectively, compared to 2012, as a result of new pipeline infrastructure being added from the Cushing area to the U.S. Gulf Coast thereby relieving congestion that developed due to rapid growth in U.S. inland supply.

WCS is 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 by US$4.24 per barrel in the third quarter, compared to 2012, due to improved pipeline access from inland markets to the heavy crude oil refining complex in the U.S. Gulf Coast through pipeline expansions and more effective use of existing pipeline infrastructure. Substantial increases in rail shipments and more frequent supply outages also reduced pipeline congestion for all grades of crude oil. For the nine months of 2013, the WTI-WCS average differential widened by US$0.86 per barrel due to increased levels of congestion early in the year.

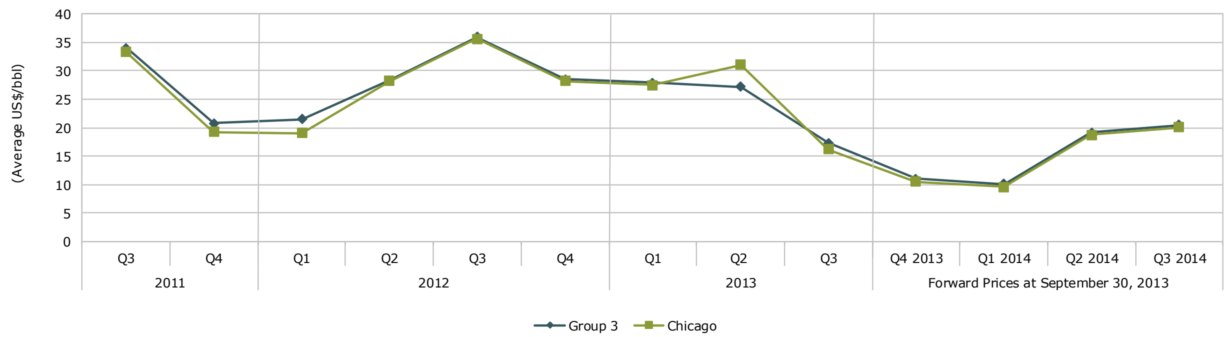


Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The WTI-Condensate differential is the Edmonton benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. Condensate differentials at Edmonton weakened by US$5.94 per barrel in the third quarter, as condensate traded at a discount to WTI for the first time since the third quarter of 2010. Despite strengthening U.S. condensate prices the reductions in pipeline congestion caused WTI prices to increase more than condensate prices. Year-to-date, condensate differentials strengthened by US$0.37 per barrel, compared to 2012, as greater access to export markets for U.S. condensate improved Gulf Coast prices and growing Canadian condensate requirements saw a further strengthening of Edmonton prices, which was partially offset by strengthening WTI prices.

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 and on a last in, first out accounting basis. 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 feedstock costs which are based on a first in, first out accounting basis. Average market crack spreads in the U.S. inland Chicago and Group 3 markets for the third quarter of 2013 fell sharply compared to 2012, primarily due to the strengthening of WTI prices as inland congestion issues were being resolved and as a result of higher refinery crude oil runs which kept product markets well supplied. Average market crack spreads for the Chicago and Group 3 markets also fell year-to-date, due to the rise in WTI prices in the third quarter of 2013.

Refining 3-2-1 Crack Spread Benchmarks



Other Benchmarks

Average natural gas prices increased in both the third quarter and the nine months of 2013 as the impact to markets from growth in northeastern U.S. natural gas production and an extremely warm winter in the previous year was gradually reduced. The low prices of 2012 have significantly slowed the pace of supply growth outside of the northeastern U.S., while steady demand growth has enabled markets to be balanced without price-induced switching from coal to gas-fired generation in the power sector.

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 improves our reported results, although a weaker Canadian dollar also inflates our current period's reported refining capital investment. For the three and nine months ended September 30, 2013, the Canadian dollar weakened relative to the U.S. dollar, compared to the same periods last year, caused by a general downturn in commodity markets.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section.

($ millions, except per share amounts)	Nine Months Ended September 30, 2013	2012	2013 Q3	Q2	Q1	2012 Q4	Q3	Q2	Q1	2011 Q4	Q3
Revenues	**13,910**	13,118	**5,075**	4,516	4,319	3,724	4,340	4,214	4,564	4,329	3,858
Operating Cash Flow (1)	**3,478**	3,473	**1,148**	1,119	1,211	963	1,310	1,078	1,085	1,019	945
Cash Flow (1)	**2,774**	2,946	**932**	871	971	697	1,117	925	904	851	793
Per Share – Diluted	**3.66**	3.88	**1.23**	1.15	1.28	0.92	1.47	1.22	1.19	1.12	1.05
Operating Earnings (1) (2)	**959**	1,056	**313**	255	391	(188)	432	284	340	332	303
Per Share – Diluted (2)	**1.27**	1.39	**0.41**	0.34	0.52	(0.25)	0.57	0.37	0.45	0.44	0.40
Net Earnings (2)	**720**	1,112	**370**	179	171	(117)	289	397	426	266	510
Per Share – Basic (2)	**0.95**	1.47	**0.49**	0.24	0.23	(0.15)	0.38	0.53	0.56	0.35	0.68
Per Share – Diluted (2)	**0.95**	1.47	**0.49**	0.24	0.23	(0.15)	0.38	0.52	0.56	0.35	0.67
Capital Investment (3)	**2,364**	2,390	**743**	706	915	978	830	660	900	903	631
Cash Dividends	**549**	498	**182**	183	184	167	166	166	166	151	150
Per Share	**0.726**	0.66	**0.242**	0.242	0.242	0.22	0.22	0.22	0.22	0.20	0.20

(1) Non-GAAP measure and defined in this MD&A.
(2) We have restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more details.
(3) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

Revenues Variance

During the three and nine months ended September 30, 2013, revenues increased $735 million (17 percent) and $792 million (six percent), respectively.

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2012	**4,340**	**13,118**
Increase (Decrease) due to:		
Oil Sands	**345**	**434**
Conventional	**87**	**172**
Refining and Marketing	**393**	**463**
Corporate and Eliminations	**(90)**	**(277)**
Revenues for the Periods Ended September 30, 2013	**5,075**	**13,910**

Upstream revenues rose for the third quarter by 31 percent due to higher crude oil sales and condensate prices, a rise in crude oil sales and condensate volumes and higher realized natural gas prices, partially offset by lower natural gas production.

Year-to-date upstream revenues rose 14 percent due to increased crude oil sales volumes, higher natural gas sales prices, a rise in condensate volumes used in blending, higher crude oil sales prices, reduced royalties and increased condensate prices, offset by a decline in natural gas production.

Revenues for the three and nine months ended September 30, 2013 generated by the Refining and Marketing segment increased 13 percent and five percent, respectively. In the third quarter of 2013, we had higher revenues from third party sales, undertaken to provide operational flexibility, primarily due to an increase in purchased crude oil volumes and increases in crude oil and condensate pricing, as well as higher revenue from refining primarily as a result of increased refined product output.

Revenue from third party sales was higher on a year-to-date basis as a result of increased purchased crude oil volumes and higher crude oil and condensate pricing. Refining revenue increased due to a weakening of the Canadian dollar and an increase in refined product prices, partially offset by reduced refined product output, as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Cash Flow

Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. 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. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2013**	2012	**2013**	2012
Revenues	**5,265**	4,440	**14,352**	13,283
(Add Back) Deduct:				
Purchased Product	**3,172**	2,403	**8,065**	7,500
Transportation and Blending	**464**	398	**1,482**	1,323
Operating Expenses	**437**	419	**1,342**	1,203
Production and Mineral Taxes	**11**	9	**30**	28
Realized (Gain) Loss on Risk Management Activities	**33**	(99)	**(45)**	(244)
Operating Cash Flow	**1,148**	1,310	**3,478**	3,473

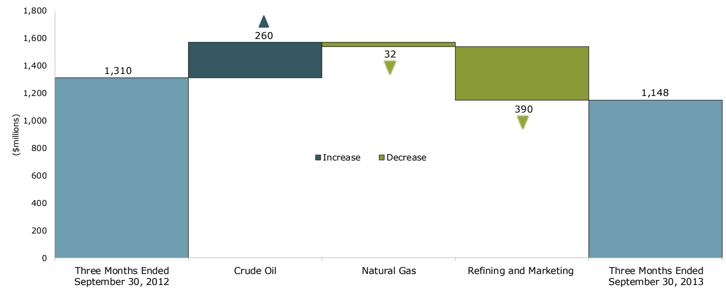
Operating Cash Flow Variance for the Three Months Ended September 30, 2013 compared to September 30, 2012

In the third quarter, Operating Cash Flow decreased $162 million (12 percent).

Operating Cash Flow from crude oil increased 40 percent due to higher average sales prices, consistent with the increase in the WTI benchmark price and the WTI-WCS differential narrowing, and increased production volumes, partially offset by realized risk management losses as compared to gains in 2012, and higher operating and transportation and blending expenses.

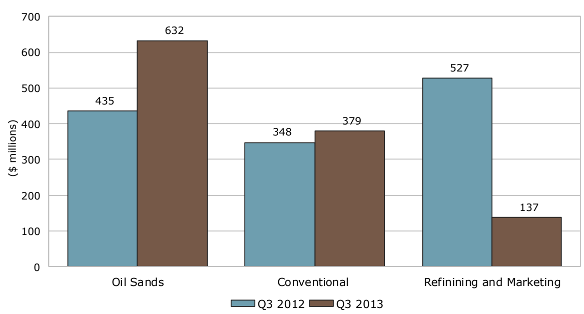
Operating Cash Flow from natural gas decreased 25 percent as lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.

Operating Cash Flow Variance for the Three Months Ended September 30, 2013 compared to September 30, 2012

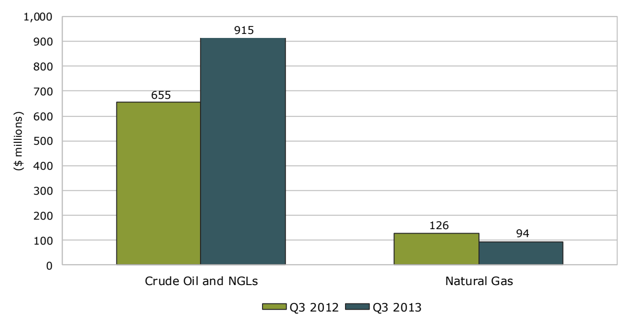


Refining and Marketing Operating Cash Flow declined 74 percent primarily related to the sharp decline in the market crack spreads and increases in refinery feedstock costs, consistent with the narrowing of the WTI-WCS differential and increases in the cost of RINs, partially offset by higher refined product output.

Operating Cash Flow by Segment



Upstream Operating Cash Flow by Product



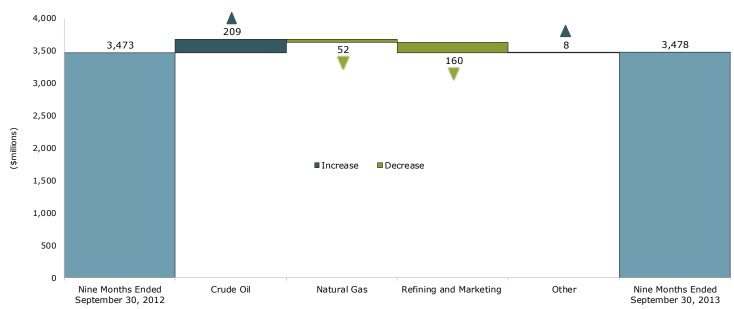
Operating Cash Flow Variance for the Nine Months Ended September 30, 2013 compared to September 30, 2012

Year-to-date, Operating Cash Flow increased $5 million.

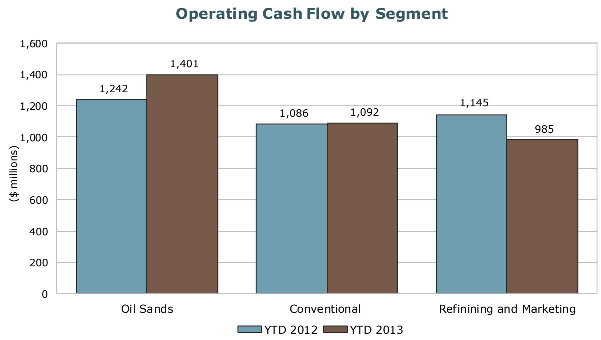
Operating Cash Flow from crude oil increased 11 percent due to growing production volumes, higher average sales prices consistent with the increase in benchmark prices, and a reduction in royalties, partially offset by higher operating expenses.

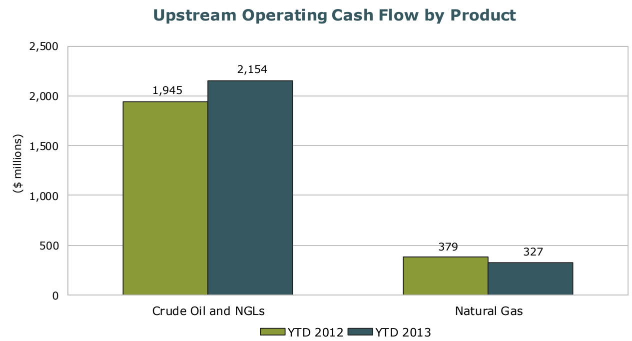
Operating Cash Flow from natural gas declined 14 percent due to lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.

Operating Cash Flow Variance for the Nine Months Ended September 30, 2013 compared to September 30, 2012



Refining and Marketing Operating Cash Flow was lower by 14 percent due to lower market crack spreads, higher refinery feedstock costs, consistent with the increase in the WCS benchmark price and increases in the cost of RINs, and decreased refined product output as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.





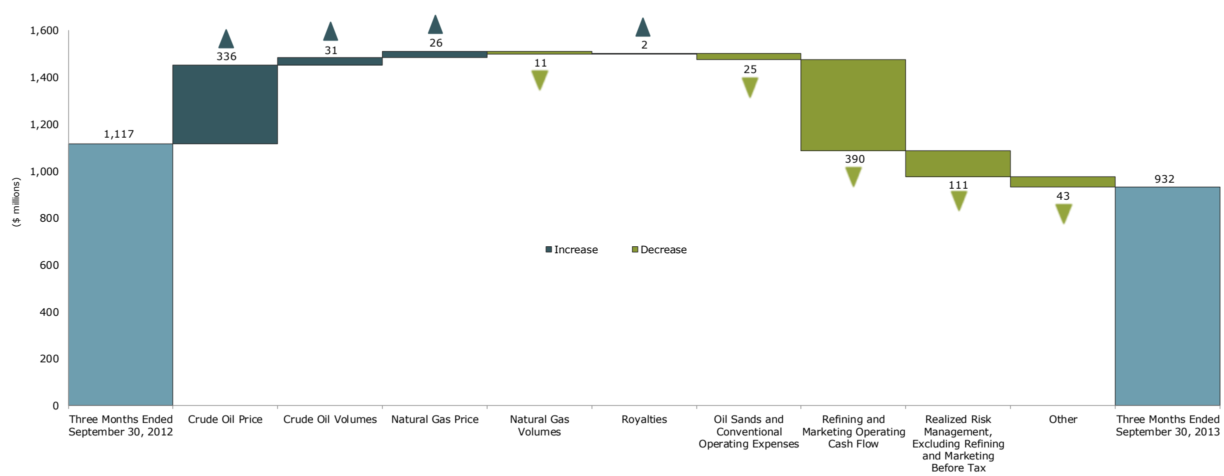
Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

Cash Flow is a non-GAAP measure 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 is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Cash From Operating Activities	**840**	1,029	**2,563**	2,662
(Add Back) Deduct:				
Net Change in Other Assets and Liabilities	**(25)**	(19)	**(90)**	(71)
Net Change in Non-Cash Working Capital	**(67)**	(69)	**(121)**	(213)
Cash Flow	**932**	1,117	**2,774**	2,946

Cash Flow Variance for the Three Months Ended September 30, 2013 compared to September 30, 2012



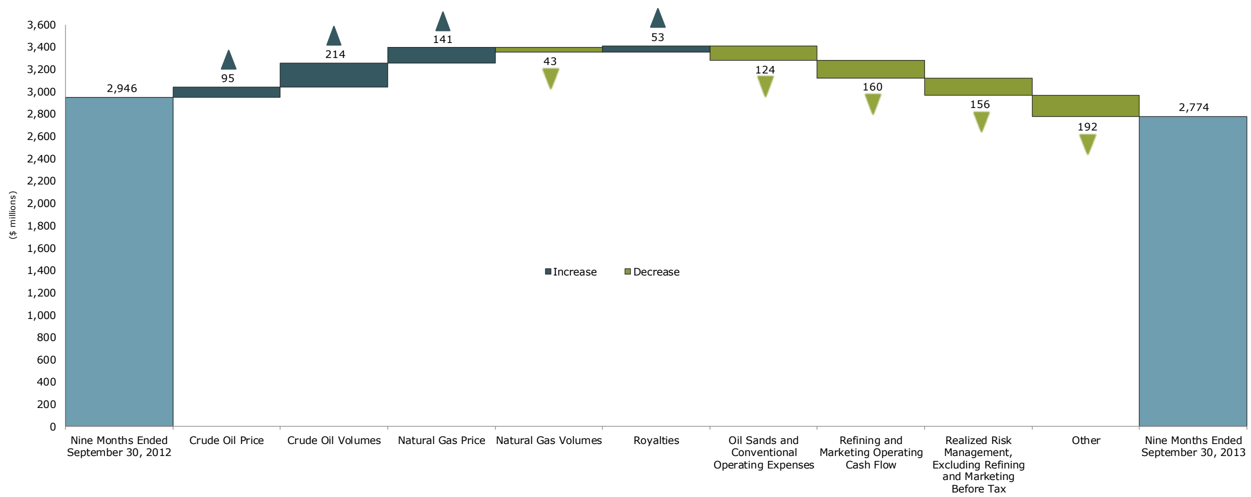
In the third quarter, our Cash Flow decreased $185 million or 17 percent due to:

- A decline in Operating Cash Flow from Refining and Marketing of $390 million related to the sharp decline in market crack spreads and increases in refinery crude oil feedstock costs consistent with the narrowing of the WTI-WCS differential and higher costs associated with RINs, partially offset by higher refined product output;
- Realized risk management losses before tax, excluding Refining and Marketing, of $12 million compared to gains of $99 million in 2012;
- An increase in finance costs primarily due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014;
- An increase in crude oil upstream operating expenses of $26 million, partially from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.15 to $15.29 per barrel due to higher fuel prices, consistent with the increase in the benchmark AECO natural gas price and increased fuel usage; higher workover activities; and rising electricity costs as a result of increases in market prices and consumption; and
- A nine percent decline in natural gas production from expected natural declines.

The decreases in our Cash Flow were partially offset by:

- A 32 percent increase in our average sales price of crude oil to $86.28 per barrel;
- A decrease in current tax of $36 million as it includes a recovery of U.S. tax which reflects lower estimates of U.S. source income for 2013;
- An increase in our crude oil sales volumes by three percent; and
- A 23 percent increase in our average sales price of natural gas to $2.83 per Mcf.

Cash Flow Variance for the Nine Months Ended September 30, 2013 compared to September 30, 2012



Year-to-date, our Cash Flow decreased $172 million primarily due to:

- A decrease in Operating Cash Flow from Refining and Marketing of $160 million as a result of lower market crack spreads, increases in refinery crude oil feedstock costs consistent with increases in benchmark prices and higher costs associated with RINs, and declines in refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter;
- Realized risk management gains before tax, excluding Refining and Marketing, of $74 million compared to gains of $230 million in 2012;
- An increase in upstream operating expenses of $124 million, partially from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.61 to $15.88 per barrel primarily due to higher fuel prices, consistent with the increase in the AECO benchmark price and increased fuel usage; increased workover activities related to Foster Creek and Pelican Lake; and rising electricity costs, as a result of higher market rates and consumption;
- Increased general and administrative expenses, excluding non-cash long-term incentive costs, due to higher rent and staffing costs;
- Pre-exploration expense of $63 million recorded in the second quarter of 2013;
- An 11 percent decline in natural gas production from expected natural declines; and
- An increase in finance costs primarily due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014.

The decreases in our Cash Flow were partially offset by:

- A seven percent increase in our crude oil sales volumes;
- A 42 percent increase in our average sales price of natural gas to $3.20 per Mcf;
- A three percent increase in our average sales price of crude oil to $69.91 per barrel; and
- A decrease in royalties of $53 million primarily at Foster Creek as a result of lower crude oil production volumes and increased capital and operating expenditures.

Operating Earnings

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as net earnings excluding 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 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.

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Net Earnings	**370**	289	**720**	1,112
Add Back (Deduct):				
Unrealized Risk Management (Gain) Loss, after-tax (1)	**(5)**	218	**147**	44
Non-operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2)	**(53)**	(76)	**91**	(100)
Gain (Loss) on Divestiture of Assets, after-tax	**1**	1	**1**	-
Operating Earnings	**313**	432	**959**	1,056

(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 decreased $119 million or 28 percent in the third quarter, primarily as a result of:
- Lower Cash Flow as discussed above; and
- Increase in DD&A of $33 million primarily due to higher DD&A rates.

The decrease in Operating Earnings was partially offset by:
- A decline in deferred income tax expense of $56 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, primarily because of decreased U.S. income; and
- A realized foreign exchange gain of $33 million on the early redemption of the US$800 million of senior unsecured notes that was due in September 2014.

Year-to-date Operating Earnings decreased $97 million or nine percent, primarily as a result of:
- Increased DD&A of $189 million, including an impairment loss on our Lower Shaunavon asset held for sale, recorded in the second quarter of 2013; and
- Previously discussed declines in Cash Flow.

The decline in Operating Earnings was partially offset by:
- A decrease in deferred income tax expense of $164 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses;
- No non-cash long-term incentive expense or recovery in 2013 as compared to an expense in 2012;
- Lower exploration expense; and
- A realized foreign exchange gain of $33 million on the extinguishment of debt.

Net Earnings Variance

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2012	**289**	**1,112**
Increase (Decrease) due to:		
Operating Cash Flow	**(162)**	**5**
Corporate and Eliminations:		
Unrealized Risk Management (Gain) Loss, after-tax	**223**	**(103)**
Unrealized Foreign Exchange (Gain) Loss	**(12)**	**(168)**
Expenses (1)	**(27)**	**(59)**
Depreciation, Depletion and Amortization	**(33)**	**(189)**
Exploration Expense	**-**	**(41)**
Income Taxes, Excluding Income Taxes on Unrealized Risk Management (Gain) Loss	**92**	**163**
Net Earnings for the Periods Ended September 30, 2013	**370**	**720**

(1) *Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, (gain) loss on divestiture of assets, after-tax, other (income) loss, net and Corporate and Eliminations operating expenses.*

In addition to the changes discussed above in the Cash Flow and Operating Earnings sections, our net earnings increased 28 percent during the third quarter, primarily due to unrealized risk management gains, after-tax, of $5 million in the quarter, compared to losses of $218 million in 2012. These increases were partially offset by unrealized foreign exchange gains of $48 million in the quarter, compared to gains of $60 million in 2012.

For the nine months ended September 30, 2013, our net earnings decreased 35 percent primarily due to unrealized foreign exchange losses of $86 million, compared to gains of $82 million in 2012 and unrealized risk management losses after-tax of $147 million compared to losses of $44 million in 2012.

Net Capital Investment

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Oil Sands	**523**	516	**1,731**	1,606
Conventional	**178**	231	**510**	591
Refining and Marketing	**19**	38	**70**	60
Corporate	**23**	45	**53**	133
Capital Investment	**743**	830	**2,364**	2,390
Acquisitions	**1**	8	**5**	44
Divestitures	**(241)**	-	**(242)**	(65)
Net Capital Investment (1)	**503**	838	**2,127**	2,369

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

Oil Sands capital investment in 2013 has been focused on the development of the expansion phases at Foster Creek and Christina Lake, development of phase A at Narrows Lake and infill drilling activities related to our Pelican Lake polymer flood. Increases in capital investment were partially offset by declines at Telephone Lake, with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012 and the recognition of scientific research and experimental development credits in the third quarter of 2013, and decreased spending at Pelican Lake, as the rate at which we are expanding the polymer flood has slowed to better match our production growth in 2013. Capital investment includes the drilling of 337 gross stratigraphic test wells. The results of these stratigraphic test wells will be used primarily to support the expansion and development of our Oil Sands projects.

In 2013, Conventional capital investment has been centered on drilling, completion and recompletion programs as well as work on facilities, partially offset by reduced capital investment in our Shaunavon asset.

Our capital investment in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety in 2013.

Spending on technology development is included in our capital investment. Our teams look for ways to improve existing technology, evaluate new ideas and pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas and improve our refining processes.

Capital investment in our Corporate and Eliminations segment decreased as costs related to tenant improvements and information technology were lower due to the move into our new office space in the first quarter of 2013.

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

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our use 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 allows us to be financially resilient in times of lower cash flows.

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Cash Flow	**932**	1,117	**2,774**	2,946
Capital Investment (Committed and Growth)	**743**	830	**2,364**	2,390
Free Cash Flow (1)	**189**	287	**410**	556
Dividends Paid	**182**	166	**549**	498
	7	121	**(139)**	58

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

Over the next decade, we expect to increase our net crude oil production to approximately 525,000 barrels per day. In order to meet project targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 billion for the next decade. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. As at September 30, 2013, we had cash and cash equivalents of $1 billion to fund future capital investment. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of our financial metrics.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. 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, NGLs and natural gas in Alberta and Saskatchewan, including the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

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. 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.

Revenue by Reportable Segment

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Oil Sands	**1,269**	924	**3,285**	2,851
Conventional	**537**	450	**1,584**	1,412
Refining and Marketing	**3,459**	3,066	**9,483**	9,020
Corporate and Eliminations	**(190)**	(100)	**(442)**	(165)
	5,075	4,340	**13,910**	13,118

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects and we also produce heavy oil from our wholly owned Pelican Lake operations. We have several emerging projects in the early stages of assessment, including Telephone Lake and Grand Rapids. The Oil Sands segment also includes 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 compared to 2012 include:

- Christina Lake production increasing 63 percent, to an average of 52,732 barrels per day. Phase D reached full production capacity in 2013 and phase E, our tenth expansion phase, started up in July 2013;
- Foster Creek production averaging 49,092 barrels per day, a decrease of 22 percent, resulting from a number of production matters discussed below;
- Receiving regulatory approval for an optimization program at Christina Lake phases C, D and E which is expected to add 22,000 barrels per day of gross capacity in 2015; and
- Operating cash flow increasing 45 percent as a result of higher crude oil sales prices and increased production volumes.

Oil Sands – Crude Oil

Financial Results

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Gross Sales	**1,324**	998	**3,368**	2,994
Less: Royalties	**67**	84	**124**	175
Revenues	**1,257**	914	**3,244**	2,819
Expenses				
Transportation and Blending	**425**	367	**1,351**	1,211
Operating	**175**	142	**519**	405
(Gain) Loss on Risk Management	**27**	(23)	**(9)**	(20)
Operating Cash Flow	**630**	428	**1,383**	1,223
Capital Investment	**522**	515	**1,728**	1,600
Operating Cash Flow net of Related Capital Investment	**108**	(87)	**(345)**	(377)

Capital expenditures in excess of Operating Cash Flow for the Oil Sands segment are funded through Operating Cash Flow generated by our conventional and refining operations.

Production

(barrels per day)	Three Months Ended September 30, 2013	Percent Change	2012	Nine Months Ended September 30, 2013	Percent Change	2012
Foster Creek	**49,092**	**(22)%**	63,245	**53,450**	**(7)%**	57,421
Christina Lake	**52,732**	**63%**	32,380	**45,211**	**58%**	28,577
	101,824	**6%**	95,625	**98,661**	**15%**	85,998
Pelican Lake	**24,826**	**5%**	23,539	**24,162**	**9%**	22,231
	126,650	**6%**	119,164	**122,823**	**13%**	108,229

Three Months Ended September 30, 2013 Compared to September 30, 2012

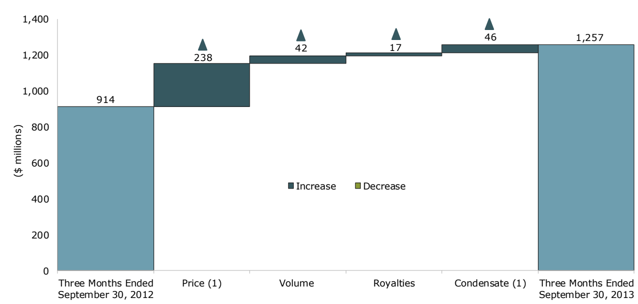
Revenue Variance

Pricing

In the third quarter, our average crude oil sales price was $82.52 per barrel, 34 percent higher than 2012, generally consistent with the increase in the WCS benchmark price and strengthening of the Christina Dilbit Blend ("CDB") price.

In the third quarter, approximately 88 percent of our Christina Lake production was sold as CDB (2012 – 85 percent), which sells at a discount to WCS. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.

Revenue Variance for the Three Months Ended September 30, 2013 Compared to September 30, 2012



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

Production

In the third quarter of 2013, Foster Creek production averaged 49,092 barrels per day, a 22 percent decrease from 2012. Our planned major turnaround began in September reducing our volumes by 4,400 barrels per day for the third quarter. We also experienced some minor treating issues in the quarter.

In the third quarter of 2012, we were producing approximately 126,000 barrels per day gross, above our nameplate capacity of 120,000 barrels per day gross. In the fourth quarter of 2012 we chose to defer some routine well maintenance until 2013. This deferral of maintenance resulted in a higher than usual inventory of well maintenance work and had a negative impact on our 2013 production volumes.

Through the nine months ended September 30, 2013, we have been able to complete the majority of our backlog in well work and have recently had time to analyze the data and more fully assess how we are operating the initial phases of Foster Creek. Based on this new information, we have made two key observations on the way we operate Foster Creek. First, with respect to wells, we require more preventative maintenance and are investing in improved instrumentation which will allow for increased data collection and monitoring capability. We have also improved our liner design, which we expect to improve reliability. The second key observation relates to the evolution to common steam chambers in the initial phases of the project and our need to focus on optimizing the formation of common steam chambers across the field rather than on a well or pad basis.

Foster Creek is the industry's first commercial SAGD project and is a top tier asset that will continue to evolve as we optimize the management of the facilities and maximize the recovery of the reserves. We expect to operate Foster Creek phases A to E at a production level of between 100,000 to 110,000 barrels per day in the near-term at a steam to oil ratio of about 2.4 to 2.5. As we continue to learn more about operating a SAGD project with one common steam chamber, we will look to further optimize production.

Christina Lake production increased as a result of phase D reaching full capacity, approximately six months after production began in the third quarter of 2012, and phase E production continuing to ramp up as expected after first production in mid-July 2013. In the third quarter, we had unplanned minor downtime related to phase E start-up and commissioning.

Pelican Lake production continues to increase from additional infill wells coming on-stream throughout 2012 and 2013 and increased response from our polymer flood program.

Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent) to the gross revenues from the project. Gross revenues are a function of volumes and realized prices.

Royalties for Foster Creek and Pelican Lake, post-payout projects, use an annualized calculation which is based on the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of volumes, realized prices and allowed operating and capital costs.

Royalties decreased in the third quarter primarily as a result of lower volumes at Foster Creek with the production matters noted above, and the commencement of the planned turnaround, as well as increased projected annual capital expenditures and operating costs resulting in a royalty calculation based on gross revenues.

Effective Royalty Rates

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(percent)	**2013**	2012	**2013**	2012
Foster Creek	**7.6**	19.1	**5.7**	13.0
Christina Lake	**7.0**	5.3	**6.4**	6.4
Pelican Lake	**7.7**	6.6	**6.7**	5.1

Expenses

Transportation and Blending

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce its viscosity in order to transport the product to market. Transportation and blending costs rose $58 million or 16 percent in the third quarter. Blending costs rose $46 million, mainly due to the higher average cost of condensate and increased condensate volumes required for blending with the increase in production at Christina Lake, offset by lower production volumes at Foster Creek. Transportation charges were higher due to production increases and higher sales into the U.S. market which attract higher tariffs.

Operating

Our operating costs for the third quarter were primarily for workforce, workover activities, repairs and maintenance and fuel costs. In total, operating costs increased $33 million or $2.08 per barrel.

Per-unit Operating Costs

($/bbl)	Three Months Ended September 30, 2013	Percent Change	2012	Nine Months Ended September 30, 2013	Percent Change	2012
Foster Creek	**17.12**	**49%**	11.50	**15.73**	**28%**	12.26
Christina Lake	**11.46**	**(16)%**	13.59	**13.42**	**(2)%**	13.76
Pelican Lake	**19.90**	**14%**	17.47	**20.46**	**20%**	17.04

At Foster Creek operating costs rose $5.62 per barrel or $13 million. The total dollar increase was associated with:

- Workover activities, as we continue to resolve production matters;
- Repairs and maintenance and workforce costs as a result of a planned turnaround commencing in late September; and
- Fuel prices consistent with the rising benchmark AECO natural gas price and higher fuel consumption.

Increases were partially offset by a decline in chemical costs due to the planned turnaround and the operational issues mentioned above.

Christina Lake operating costs decreased $2.13 on a per barrel basis as a result of higher production volumes. The total dollar increase of $16 million was due to:

- Increasing fuel usage, as a result of rising production and higher fuel prices consistent with the benchmark AECO natural gas price;
- Additional repairs and maintenance costs mainly related to routine maintenance;
- Higher workforce, workover and chemicals costs associated with increased production; and
- Electricity due to higher prices and increased consumption.

Operating costs at Pelican Lake increased $2.43 on a per barrel basis or $4 million due to higher chemical costs and consumption related to the expansion of the polymer flood program and property taxes as a result of the expanded development areas.

Risk Management

Risk management activities resulted in realized losses of $27 million in the third quarter of 2013 (2012 – realized gains of $23 million), consistent with the average benchmark prices exceeding our contract prices.

Nine Months Ended September 30, 2013 Compared to September 30, 2012

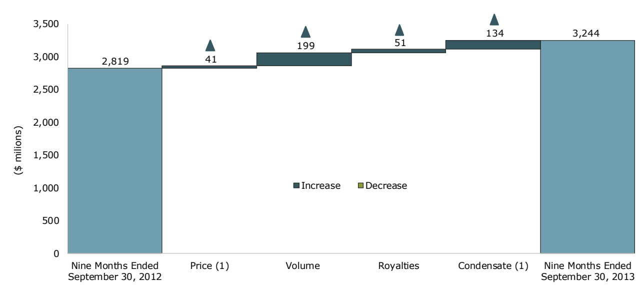
Revenue Variance

Pricing

For the nine months ended September 30, 2013, our average crude oil sales price was $64.29 per barrel, a two percent increase from 2012, generally consistent with the increase in the WCS benchmark price and strengthening of the CDB price.

Approximately 88 percent of our Christina Lake production was sold as CDB (2012 – 70 percent), which sells at a discount to WCS. The CDB price differential to WCS improved $1.34 per barrel compared to 2012, as CDB continues to gain wider market acceptance in 2013. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.

Revenue Variance for the Nine Months Ended September 30, 2013 Compared to September 30, 2012



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

Production

Year-to-date production declined at Foster Creek as we have been catching up on the backlog of well maintenance because of a decision made in the fourth quarter of 2012 to defer some of that work. Most of the maintenance backlog is now complete. The substantial increase in production at Christina Lake resulted from phase D, which started up in the third quarter of 2012 and reached full production capacity in 2013, and the start-up of phase E in mid-July 2013. Pelican Lake production increased due to additional infill wells coming on-stream throughout 2012 and 2013 as well as increased response from our polymer flood program.

Royalties

Year-to-date, royalties decreased $51 million primarily related to lower volumes and increased projected annual capital expenditures and operating expense at Foster Creek resulting in a royalty calculation based on gross revenues.

Expenses

Transportation and Blending

Transportation and blending costs rose $140 million or 12 percent year-to-date. Blending costs increased $134 million, mainly due to the increased condensate volumes required for blending with the increase in production from Christina Lake and higher average condensate prices. Transportation charges were higher mainly due to the production growth at Christina Lake.

Operating

Year-to-date, operating costs were primarily for workforce, workover activities, fuel, repairs and maintenance and chemicals. In total, operating costs increased $114 million.

At Foster Creek, operating costs rose $3.47 per barrel or $36 million. The total dollar increase was related to:

- Increased workover activities, as we continue to resolve production matters;
- Rising fuel prices, consistent with the increase in the benchmark AECO natural gas price and higher fuel consumption;
- Higher workforce to support expansions; and
- Higher electricity as a result of increased market rates on purchased electricity, while our cogeneration units were down for maintenance. The cogeneration units returned to operation in July 2013.

Increases were partially offset by lower repairs and maintenance with the 2013 planned turnaround being completed in the fourth quarter. The 2012 planned turnaround was completed in the second quarter.

Christina Lake operating costs decreased $0.34 on a per barrel basis. The total dollar increase of $56 million was related to:

- Higher fuel prices, consistent with the benchmark AECO natural gas price and increased usage to support production growth;
- Higher workforce to support expansions;
- Additional waste, fluid handling and trucking costs due to treating and emulsion hauling associated with the ramp-up of phase D and E and the planned turnaround in the second quarter of 2013; and
- Increased repairs and maintenance cost associated with the planned turnaround.

Operating costs at Pelican Lake increased $3.42 on a per barrel basis or $22 million. The total dollar increase was due to increased workover activities due to equipment failure, additional chemical consumption related to expansion of the polymer flood and electricity with a rise in market rates and higher consumption.

Risk Management

Risk management activities resulted in realized gains of $9 million (2012 – realized gains of $20 million) year-to-date, consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production for the three and nine months ended September 30, 2013 was 25 MMcf per day and 23 MMcf per day, respectively, decreasing as the result of expected natural declines. The internal use of our natural gas production at Foster Creek decreased in the three months ended September 30, 2013 due to the commencement of a planned turnaround in September 2013 and other plant downtime. Internal use of natural gas increased slightly on a year-to-date basis.

Operating Cash Flow was $13 million year-to-date (2012 – $21 million) due primarily to lower realized gains on risk management.

Oil Sands – Capital Investment

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Foster Creek	**205**	199	**604**	527
Christina Lake	**162**	147	**499**	425
	367	346	**1,103**	952
Pelican Lake	**96**	128	**350**	371
Narrows Lake	**40**	7	**90**	25
Telephone Lake	**1**	13	**71**	117
Grand Rapids	**6**	7	**32**	46
Other (1)	**13**	15	**85**	95
Capital Investment (2)	**523**	516	**1,731**	1,606

(1) *Includes new resource plays and Athabasca natural gas.*
(2) *Includes expenditures on PP&E and E&E assets.*

Foster Creek

Capital investment for the third quarter was higher due to phase F pipeline construction and drilling and phase H procurement, partially offset by a reduction in phase G engineering and procurement. For the nine months ended September 30, 2013, spending increased mainly due to phase H site preparation, piling and procurement, phase F drilling and phase G piling and procurement. Year-to-date spending includes the drilling of 111 gross stratigraphic test wells (2012 – 124 gross wells), maintenance capital and the construction of a new camp facility.

Christina Lake

Christina Lake capital investment increased for the three and nine months ended September 30, 2013, primarily due to phase F plant construction, procurement and engineering and phase E plant and well pad construction and drilling of well pairs. Year-to-date capital investment also includes the drilling of stratigraphic test wells (2013 – 69 gross wells; 2012 – 97 gross wells) and maintenance and infrastructure capital.

Pelican Lake

Pelican Lake capital investment was lower in the three and nine months ended September 30, 2013 as the rate at which we were expanding the polymer flood has slowed to better match our production growth. These decreases were partially offset by engineering and procurement for long lead items related to facility construction and maintenance. Capital investment also included the drilling of six stratigraphic test wells (2012 – five wells).

Narrows Lake

Capital investment increased at Narrows Lake in the third quarter and year-to-date due to engineering and procurement, commencement of phase A plant construction in August 2013, and infrastructure. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 38 gross wells).

Telephone Lake

Capital investment on the dewatering pilot, which commenced in the fourth quarter of 2012, continued in 2013 with the removal and reinjection of water and monitoring of results. Capital investment decreased in the third quarter, as increases related to the dewatering pilot were offset by the recognition of $16 million in scientific research and experimental development credits. In the nine months ended September 30, 2013, capital investment was lower than the prior period with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Gross Production Wells Drilled (1)

	Nine Months Ended September 30, 2013	2012
Foster Creek	**31**	20
Christina Lake	**18**	25
	49	45
Pelican Lake	**38**	52
Grand Rapids	**-**	1
	87	98

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

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. Additional production capacity of 45,000 gross barrels per day is expected from phase F in the third quarter of 2014, with production from phases G and H expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February

2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Foster Creek capital investment for 2013 is forecasted to be between $810 million and $830 million.

At Christina Lake, phase E development spending for the completion of drilling and well pad and facility construction is expected to continue to the end of 2014. We expect the ramp-up of phase E will take six to nine months overall, similar to phases C and D, with production capacity expected to reach 138,000 barrels per day gross early in 2014. We received regulatory approval to add cogeneration facilities and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G in the fourth quarter of 2012. Expansion work on these phases is continuing in 2013 as planned and we expect production from phases F and G in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program at Christina Lake phases C, D and E which is expected to add 22,000 barrels per day of gross capacity in 2015. We submitted a joint application and EIA to regulators in March 2013 for the phase H expansion, a 50,000 barrel per day phase, for which we expect to receive regulatory approval in the fourth quarter of 2014. In 2013, Christina Lake capital investment is forecasted to be between $675 million and $690 million.

At Pelican Lake, we are continuing with the infill drilling program in addition to piloting new techniques to optimize production. In 2013, the rate at which we are expanding the polymer flood, including construction of a new battery, has slowed to better match our production growth. In 2013, Pelican Lake capital investment is forecasted to be between $480 million and $500 million.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A. We are continuing with site construction, engineering and procurement and construction of the phase A plant started in the third quarter of 2013. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $150 million and $160 million in 2013.

Additional capital investment of approximately $240 million to $250 million in 2013 is expected for our emerging SAGD projects, including Telephone Lake and Grand Rapids. At Telephone Lake, we are advancing the regulatory application for the project and anticipate receiving approval in the second quarter of 2014. In 2013, we are continuing with the dewatering pilot and plan to complete the pilot by the end of October 2013. We have successfully replaced water and confined air, displacing approximately 65 percent of below ground top water in the pilot area to date.

At Grand Rapids we anticipate regulatory approval by the end of 2013. Steam injection started on the second pilot well pair in the third quarter of 2012 and first production was achieved in February 2013. The pilot experienced facility constraints that impacted the production of both well pairs in the first half of 2013. A facility turnaround was performed in the third quarter of 2013 that mitigated these constraints.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed another stratigraphic test well program over the winter drilling season. The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake are to support the expansion phases, while the other stratigraphic test wells were drilled to continue gathering 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 in the winter months, typically between the end of the fourth quarter and the end of the first quarter. Since 2012, we have been developing the SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. This rig does not require roads for many of its locations and reduces the water, drill cuttings and pad size compared to traditional drilling methods. Our first prototype rig has now drilled 42 wells and we are completing the construction of a second rig.

Gross Stratigraphic Test Wells Drilled

	Nine Months Ended September 30, 2013	2012
Foster Creek	**111**	124
Christina Lake	**69**	97
	180	221
Pelican Lake	**6**	5
Narrows Lake	**26**	38
Telephone Lake	**28**	29
Grand Rapids	**1**	41
Other	**96**	95
	337	429

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, and developing tight oil assets in Alberta. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

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

- Crude oil production averaging 50,288 barrels per day, decreasing four percent primarily as successful horizontal well performance associated with our current drilling program was offset by the sale of our Shaunavon asset; and
- Generating Operating Cash Flow, net of capital investment, of $201 million, an increase of 72 percent from 2012.

Conventional – Crude Oil

Financial Results

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Gross Sales	**455**	368	**1,258**	1,187
Less: Royalties	**51**	38	**125**	130
Revenues	**404**	330	**1,133**	1,057
Expenses				
Transportation and Blending	**34**	27	**115**	96
Operating	**71**	78	**236**	224
Production and Mineral Taxes	**10**	7	**28**	24
(Gain) Loss on Risk Management	**4**	(9)	**(17)**	(9)
Operating Cash Flow	**285**	227	**771**	722
Capital Investment	**173**	224	**493**	562
Operating Cash Flow Net of Related Capital Investment	**112**	3	**278**	160

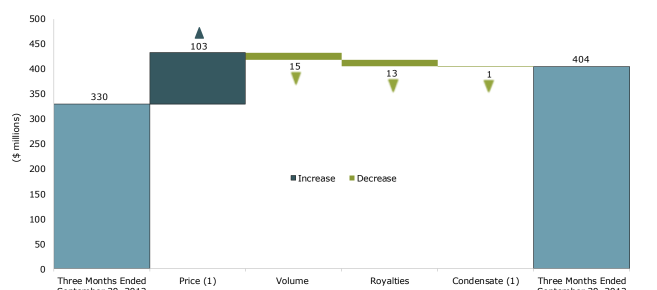
Production

(barrels per day)	Three Months Ended September 30, 2013	Percent Change	2012	Nine Months Ended September 30, 2013	Percent Change	2012
Heavy Oil	**15,507**	**-%**	15,492	**16,163**	**1%**	15,938
Light and Medium Oil	**33,651**	**(6)%**	35,695	**36,081**	**-%**	36,083
NGLs	**1,130**	**13%**	999	**1,018**	**(2)%**	1,041
	50,288	**(4)%**	52,186	**53,262**	**-%**	53,062

Three Months Ended September 30, 2013 Compared to September 30, 2012

Revenue Variance

Revenue Variance for the Three Months Ended September 30, 2013 Compared to September 30, 2012



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

Pricing

In the third quarter, our average crude oil sales price increased 30 percent to $95.54 per barrel, consistent with the change in crude oil benchmark prices and the narrowing of associated differentials.

Production

Our crude oil production was 1,898 barrels per day lower in the third quarter primarily due to a 2,044 barrels per day decline in light and medium crude oil production as a result of the sale of our Shaunavon asset in July 2013, partially offset by improved horizontal well performance. During the third quarter of 2013 we had no production volumes associated with Shaunavon (2012 – 4,550 barrels per day).

Royalties

Royalties increased by $13 million in the quarter, as a result of higher crude oil prices, partially offset by a decline in production volumes. The effective crude oil royalty rate in the third quarter for the Conventional segment was

12.4 percent (2012 – 11.1 percent). Most of our crude oil production in the Conventional segment is located on fee lands which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs were $7 million higher for the third quarter. Transportation costs rose $8 million due to the higher cost associated with transporting our light and medium crude oil production by rail. During the quarter, we transported approximately 4,100 barrels per day by rail to the East Coast and the U.S. (2012 – 3,150 barrels per day). The overall cost of condensate used in blending decreased $1 million as a result of lower condensate volumes, partially offset by higher condensate prices.

Operating

In the third quarter of 2013, operating costs of $71 million were predominantly composed of workover activities, electricity and workforce. Compared to the third quarter of 2012, operating costs declined $7 million primarily due to decreases in production volumes as a result of the Shaunavon sale, partially offset by rising electricity costs due to higher market rates.

Risk Management

Risk management activities in the third quarter resulted in realized losses of $4 million (2012 – realized gains of $9 million) consistent with the average benchmark prices exceeding our contract prices.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment increased by $109 million in the third quarter due to higher Operating Cash Flow and lower capital investment.

Nine Months Ended September 30, 2013 Compared to September 30, 2012

Revenue Variance

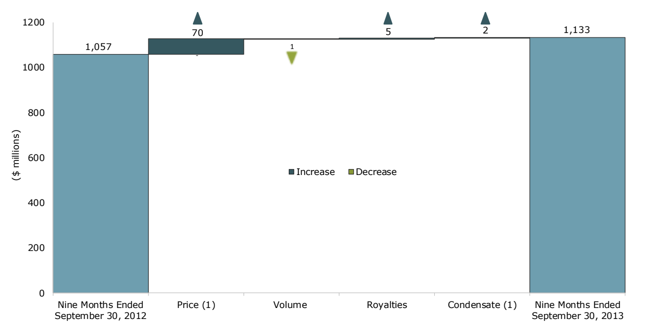
Pricing

Year-to-date, our average crude oil sales price increased six percent to $82.61 per barrel, consistent with the change in crude oil benchmark prices and as a result of higher realized prices on volumes shipped by rail.

Production

Overall, our crude oil production remained flat as higher heavy crude oil production was offset by reduced production from the sale of our Shaunavon asset in July 2013. During the nine months ended September 30, 2013, Shaunavon production averaged 2,807 barrels per day (2012 – 4,265 barrels per day).

Revenue Variance for the Nine Months Ended September 30, 2013 Compared to September 30, 2012



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

Royalties

Royalties decreased $5 million largely due to lower royalties in Suffield as a result of lower production volumes, partially offset by higher prices. The effective crude oil royalty rate during the nine months of the year was 11.1 percent (2012 – 12.2 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $19 million year-to-date. Transportation costs rose $17 million due to the higher cost associated with transporting our light and medium crude oil production by rail. During the nine months of 2013, we transported approximately 6,000 barrels per day by rail to the East Coast and the U.S. (2012 – 2,000 barrels per day). The overall cost of condensate used in blending increased $2 million as a result of higher condensate volumes and higher condensate prices.

Operating

Year-to-date, operating costs were predominantly composed of workforce, workover activities, and electricity. Operating costs rose $12 million as compared to 2012, primarily due to rising electricity costs from higher market rates, increased workforce costs, higher property taxes and workover activities associated with high-return well optimizations that have helped mitigate production declines, partially offset by declines in repairs and maintenance.

Risk Management

Risk management activities resulted in realized gains of $17 million (2012 – realized gains of $9 million), consistent with our contract prices exceeding average benchmark prices.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment, increased by $118 million due to higher Operating Cash Flow and lower capital investment.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Gross Sales	**130**	116	**447**	350
Less: Royalties	**2**	1	**6**	4
Revenues	**128**	115	**441**	346
Expenses				
Transportation and Blending	**4**	4	**15**	15
Operating	**50**	53	**155**	155
Production and Mineral Taxes	**1**	2	**2**	4
(Gain) Loss on Risk Management	**(18)**	(62)	**(45)**	(186)
Operating Cash Flow	**91**	118	**314**	358
Capital Investment	**5**	7	**17**	29
Operating Cash Flow Net of Related Capital Investment	**86**	111	**297**	329

Three Months Ended September 30, 2013 Compared to September 30, 2012

Revenues Variance

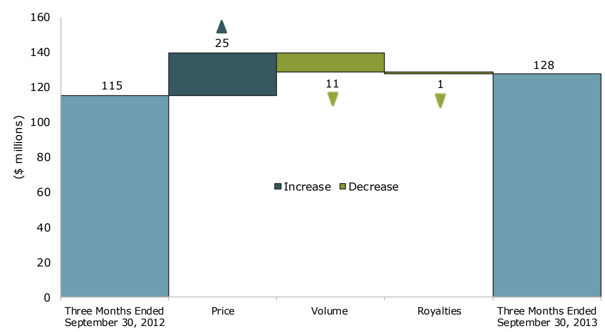
Pricing

In the third quarter, our average natural gas sales price increased $0.54 per Mcf to $2.85 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased nine percent to 498 MMcf per day in the third quarter primarily due to expected natural declines.

Revenue Variance for the Three Months Ended September 30, 2013 Compared to September 30, 2012



Royalties

Royalties increased in the third quarter as a result of higher prices, despite production declines. The average royalty rate in the third quarter was 1.5 percent (2012 – 1.1 percent). Most of our natural gas production in the Conventional segment is located on fee lands where we hold mineral rights which results in mineral tax being recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs remained flat as a result of higher pipeline rates offset by lower production volumes.

Operating

Our operating expenses were composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses decreased $3 million due to a reduction in natural gas production.

Risk Management

Risk management activities resulted in realized gains in the third quarter of $18 million (2012 – realized gains of $62 million), consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

Our Conventional natural gas assets generate significant Operating Cash Flow with minimal capital investment. Operating Cash Flow, net of capital investment decreased 23 percent to $86 million in the third quarter due to lower Operating Cash Flow and relatively flat capital investment.

Nine Months Ended September 30, 2013 Compared to September 30, 2012

Revenue Variance

Pricing

Year-to-date, our average natural gas sales price increased $0.95 per Mcf to $3.20 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

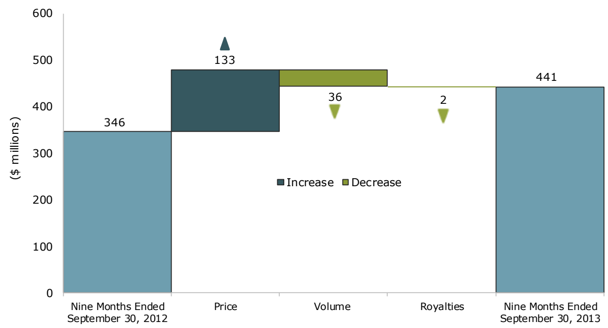
Production

Production decreased 10 percent to 512 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased as a result of higher prices, despite declines in production. The average royalty rate was 1.5 percent (2012 – 1.3 percent).

Revenue Variance for the Nine Months Ended September 30, 2013 Compared to September 30, 2012



Expenses

Transportation

Transportation costs remained flat year-to-date with higher pipeline rates offset by lower production volumes.

Operating

For the nine months ended September 30, 2013, our operating expenses are composed primarily of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses remained flat when compared to 2012.

Risk Management

Risk management activities resulted in year-to-date realized gains of $45 million (2012 – realized gains of $186 million) consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow from natural gas net of capital investment decreased $32 million to $297 million, due to lower Operating Cash Flow offset by reduced capital investment.

Conventional – Capital Investment (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2013**	2012	**2013**	2012
Crude Oil	**173**	224	**493**	562
Natural Gas	**5**	7	**17**	29
	178	231	**510**	591

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

Capital investment in our Conventional segment focused on crude oil opportunities. In the three and nine months ended September 30, 2013, capital was invested primarily in our tight oil drilling programs and in drilling and facilities work at Weyburn. Spending on natural gas activities continues to be managed in response to the low price natural gas environment.

In June 2013, we entered into a purchase and sale agreement with an unrelated third party, to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of $240 million plus closing adjustments. We continue to market certain of our Bakken assets. The Bakken properties for sale had crude oil production averaging 617 barrels per day year-to-date in 2013 (2012 – 1,228 barrels per day).

Conventional Drilling Activity

(net wells, unless otherwise stated)	Nine Months Ended September 30, 2013	2012
Crude Oil	**117**	202
Recompletions	**649**	745
Gross Stratigraphic Test Wells	**32**	7

Crude oil wells drilled, primarily horizontal wells, reflect the ongoing development of our Conventional properties. Well recompletions are mostly related to low-risk southern Alberta coal bed methane development that continues to deliver acceptable rates of return.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

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

- Our refineries processing 464,000 barrels per day of crude oil, including 240,000 barrels per day of heavy crude oil, resulting in 487,000 barrels per day of refined product output, an increase of five percent, as refined product output was reduced in 2012 as a result of minor refinery outages; and
- Operating Cash Flow decreasing 74 percent to $137 million primarily due to a sharp decline in market crack spreads and higher refinery feedstock costs consistent with the increase in WCS benchmark price and the narrowing of the WTI-WCS differential, partially offset by higher refined product output.

Refinery Operations [1]

	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Crude Oil Capacity [2] (Mbbls/d)	**457**	452	**457**	452
Crude Oil Runs (Mbbls/d)	**464**	442	**440**	446
Heavy Oil	**240**	210	**223**	213
Light/Medium	**224**	232	**217**	233
Crude Utilization (percent)	**101**	98	**96**	99
Refined Products (Mbbls/d)	**487**	463	**461**	467
Gasoline	**244**	224	**230**	231
Distillate	**152**	148	**143**	152
Other	**91**	91	**88**	84

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity of Wood River increased effective January 1, 2013.

On a 100 percent basis, our refineries have a capacity of approximately 457,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine between 235,000 to 255,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy oil production.

In the three months ended September 30, 2013, the amount of crude oil processed increased five percent of which the amount of heavy crude oil increased 14 percent as both refineries operated efficiently with minimal disruptions compared to minor outages experienced in the third quarter of 2012. Year-to-date, our crude oil processed decreased one percent primarily as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter of 2013.

Our crude utilization represents the percentage of crude oil, heavy and other, that is processed in our refineries relative to the total capacity. The amount of heavy crude oils processed, such as WCS and CDB, is dependent on the quality of available crude oils with the total crude input slate being optimized to maximize economic benefit.

Total refined product output increased by five percent in the third quarter and declined one percent year-to-date, with the proportion of gasoline, distillate and other refined products remaining relatively the same. The improvement in the third quarter was primarily due to minor refinery outages in 2012. The year-to-date decline is the result of planned maintenance in the first quarter of 2013 and an unplanned hydrocracker outage in the second quarter of 2013.

Financial Results

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Revenues	**3,459**	3,066	**9,483**	9,020
Purchased Product	**3,172**	2,403	**8,065**	7,500
Gross Margin	**287**	663	**1,418**	1,520
Expenses				
Operating	**129**	136	**404**	389
(Gain) Loss on Risk Management	**21**	-	**29**	(14)
Operating Cash Flow	**137**	527	**985**	1,145
Capital Investment	**19**	38	**70**	60
Operating Cash Flow, Net of Capital Investment	**118**	489	**915**	1,085

Three Months Ended September 30, 2013 Compared to September 30, 2012

Gross Margin

The gross margin for the Refining and Marketing segment declined $376 million, or 57 percent in the third quarter, as a result of sharp declines in market crack spreads due to increases in refinery feedstock costs consistent with the increase in WTI benchmark pricing. In addition, narrower discounts on both Canadian heavy and U.S. inland crude oil and higher costs associated with RINs increased feedstock costs at our refineries, negatively affecting gross margin.

As part of the U.S. Environmental Protection Agency's ("EPA") Renewable Fuel Standards, refineries in the U.S. are obligated to blend renewable fuels (such as ethanol) into petroleum-based motors fuel products at rates determined by the EPA. To the extent they do not, refineries must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into their motor fuel products and consequently we are obligated to purchase RINs in the open market. Since the beginning of 2013, the cost of RINs has increased significantly due primarily to the current and potential impending increases to the EPA's mandated blending quotas. In the three months ended September 30, 2013, the cost associated with RINs increased $45 million compared to 2012, consistent with the increase in the ethanol benchmark price of US$0.83 per barrel. Despite the recent increase in RIN prices, these costs remain a minor component of our total refinery feedstock costs.

Operating

Total operating costs for the three months ended September 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were lower by $7 million, or five percent, due to lower maintenance expense during the quarter, partially offset by higher utilities expense from increased throughput and natural gas prices.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment decreased $390 million, or 74 percent, primarily due to declines in market crack spreads, as well as, narrower discounts on both Canadian heavy and U.S. inland crude oil, increasing feedstock costs.

Nine Months Ended September 30, 2013 Compared to September 30, 2012

Gross Margin

The gross margin for the Refining and Marketing segment declined $102 million, or seven percent, year-to-date as a result of lower market crack spreads, increases in refinery crude oil feedstock costs consistent with increases in the WCS benchmark prices, declines in refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter, and increased costs associated with RINs. The cost associated with RINs is a minor component of our total refinery feedstock costs and increased $105 million as compared to 2012, consistent with the increase in the ethanol benchmark price of US$0.64 per barrel. Refined product prices increased during the nine months ended September 30, 2013.

Operating

Total operating costs for the nine months ended September 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were higher by $15 million, or four percent, due to planned maintenance activities in the first quarter and higher utilities as natural gas prices have increased.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment declined $160 million, or 14 percent year-to-date due to lower market crack spreads, increases in refinery crude oil feedstock costs and declines in refined product output.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Wood River Refinery	**12**	22	**38**	28
Borger Refinery	**7**	15	**32**	31
Marketing	**-**	1	**-**	1
	19	38	**70**	60

Capital expenditures year-to-date focused on capital maintenance and projects improving refinery reliability and safety. In the first quarter of 2012, we recognized Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment for the nine months ended September 30, 2012.

Future capital investment may include heavy crude debottlenecking opportunities at our Wood River Refinery.

DD&A

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Oil Sands	**153**	127	**451**	352
Conventional	**220**	222	**753**	680
Refining and Marketing	**37**	36	**102**	109
Corporate and Eliminations	**20**	12	**59**	35
	430	397	**1,365**	1,176

Oil Sands DD&A in the third quarter increased $26 million (year-to-date – $99 million increase) due to additional sales volumes at Christina Lake and Pelican Lake and higher DD&A rates for all of our properties. The year-to-date DD&A rates averaged 16 percent higher due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment was $2 million lower in the third quarter (year-to-date – increased $73 million) primarily due to the sale of the Shaunavon asset. Year-to-date, DD&A was higher as a result of an increase in the average DD&A rate of eight percent from 2012 due to lower proved reserves. During the second quarter of 2013 there was an impairment loss of $57 million related to our Lower Shaunavon asset sold in July 2013.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. The increase in 2013 is due to the depreciation of our new office space leaseholds which commenced in October 2012.

CORPORATE AND ELIMINATIONS

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. Unrealized gains on risk management before tax were $8 million for the third quarter (2012 – unrealized losses of $293 million) and year-to-date unrealized losses before tax were $196 million (2012 – unrealized losses of $60 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
General and Administrative	**103**	104	**268**	253
Finance Costs	**160**	120	**407**	344
Interest Income	**(23)**	(28)	**(73)**	(84)
Foreign Exchange (Gain) Loss, net	**(55)**	(51)	**93**	(42)
(Gain) Loss on Divestitures	**1**	1	**1**	-
Other (Income) Loss, net	**-**	-	**-**	(4)
	186	146	**696**	467

Three and Nine Months Ended September 30, 2013 Compared to September 30, 2012

General and Administrative

General and administrative expenses remained consistent quarter over quarter, with slight increases in staffing and rent costs offset by slight declines in long-term incentive costs. For the nine months ended September 30, 2013, the increase of $15 million was due to higher staffing and rent costs, offset by lower long-term incentive costs.

Finance Costs

Finance costs include interest expense on our long-term debt, 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, finance costs were $40 million higher (year-to-date – $63 million increase) than 2012 due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014, interest incurred on US$1.25 billion of senior unsecured notes issued on August 17, 2012 and US$800 million of senior unsecured notes issued August 15, 2013. Increases were partially offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the third quarter was 5.2 percent (2012 – 5.2 percent) and for the nine months ended September 30, 2013 was 5.3 percent (2012 – 5.3 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. Interest income for the three and nine months ended September 30, 2013 decreased by $5 million and $11 million, respectively, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

Foreign Exchange

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Unrealized Foreign Exchange (Gain) Loss	**(48)**	(60)	**86**	(82)
Realized Foreign Exchange (Gain) Loss	**(7)**	9	**7**	40
	(55)	(51)	**93**	(42)

The majority of unrealized losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at September 30, 2013 partially offset by unrealized gains on our U.S. dollar denominated Partnership Contribution Receivable. During the third quarter a realized foreign exchange gain of $33 million was recorded on the early redemption of the US$800 million senior unsecured notes that were due in September 2014.

Income Tax Expense

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Current Tax				
Canada	**60**	56	**147**	139
United States	**(20)**	20	**38**	45
Total Current Tax	**40**	76	**185**	184
Deferred Tax	**132**	110	**211**	408
	172	186	**396**	592
Effective Tax Rate	**31.7%**	39.2%	**35.5%**	34.7%

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. 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, variations in the estimate of reserves and 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. Our effective tax rate for the third quarter has decreased in comparison to 2012 due to lower U.S. income offset by increased Canadian income. Our year-to-date effective tax rate is comparable to 2012 because the relative levels of Canadian and U.S. source income are similar.

Current tax expense for the three months ended September 30, 2013 decreased as it includes a recovery of U.S. tax which reflects lower estimates of U.S. source income for 2013. Current tax expense for the nine months ended September 30, 2013 is comparable to 2012.

Deferred income tax expense for the third quarter of 2013 is higher than in 2012 as a result of increased Canadian income, primarily due to unrealized risk management gains in the quarter as compared to losses in 2012, partially offset by decreased U.S. income. Deferred income tax expense for the nine months ended September 30, 2013 decreased compared to 2012, primarily because of lower earnings.

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Net Cash From (Used In)				
Operating Activities	**840**	1,029	**2,563**	2,662
Investing Activities	**(451)**	(741)	**(2,157)**	(2,361)
Net Cash Provided (Used) Before Financing Activities	**389**	288	**406**	301
Financing Activities	**(190)**	852	**(539)**	760
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**-**	(6)	**(3)**	(13)
Increase (Decrease) in Cash and Cash Equivalents	**199**	1,134	**(136)**	1,048

Operating Activities

Cash from operating activities was $189 million lower in the third quarter (year-to-date – decrease of $99 million). The declines in both the three and nine months ended September 30, 2013 was mainly due to decreases in Cash Flow as discussed in the Financial Results section of this MD&A.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $1,128 million at September 30, 2013 compared to $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

Cash used in investing activities in the third quarter was $290 million lower (year-to-date – decrease of $204 million) than in 2012. The change in both the three and nine months ended September 30, 2013 was primarily due to the proceeds received on the sale of our Shaunavon asset.

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 finally to growth capital. In the third quarter, we paid a dividend of $0.242 per share, an increase of 10 percent from 2012 (2012 – $0.22 per share). Total dividend payments year-to-date are $549 million (2012 – $498 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

In the third quarter, cash flow used in financing activities increased $1,042 million (year-to-date – $1,299) primarily as a result of the issuance and repayment of debt as discussed below.

On August 15, 2013, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$800 million under our U.S. base shelf prospectus. We issued US$450 million of our senior unsecured notes with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043. The net proceeds of the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014. The offering allowed us to secure favorable interest rates while also extending the weighted average term to maturity of our long-term debt.

Our long-term debt was $4,830 million at September 30, 2013 with no principal payments due until October 2019 (US$1.3 billion). The $151 million increase in long-term debt from December 31, 2012 was related to foreign exchange.

Available Sources of Liquidity

As at ($ millions)	September 30, 2013 Amount	Term
Cash and Cash Equivalents	**1,024**	**Not Applicable**
Committed Credit Facility	**3,000**	**November 2017**
Canadian Base Shelf Prospectus [(1)]	**1,500**	**June 2014**
U.S. Base Shelf Prospectus [(1)]	**US$1,200**	**July 2014**

(1) Availability is subject to market conditions.

A portion of our future cash requirements may be funded through management of our asset portfolio. In the first quarter of 2013, Cenovus decided to launch a public sales process to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. In the third quarter, the Shaunavon asset was sold for proceeds of $240 million plus closing adjustments. We continue to market certain of our Bakken properties.

On May 9, 2013, we amended our U.S. base shelf prospectus for senior unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at September 30, 2013, we have unused capacity of US$1.2 billion, the availability of which is dependent on market conditions.

In September 2013, we renegotiated our existing $3.0 billion committed credit facility extending the maturity date from November 30, 2016 to November 30, 2017.

As at September 30, 2013, 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 our non-GAAP measure of 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, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**September 30, 2013**	December 31, 2012
Debt to Capitalization	**32%**	32%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x

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 ratio of between 1.0 to 2.0 times. At September 30, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

At September 30, 2013, our financial position, as measured by our Debt to Capitalization ratio and Debt to Adjusted EBITDA ratio, remained relatively consistent with the end of 2012. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.

Outstanding Share Data and Stock-based Compensation Plans

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, 2013, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus. Options issued by Cenovus prior to February 24, 2011, have associated tandem stock appreciation rights ("TSARs") and options issued after February 24, 2011 have associated net settlement rights ("NSRs").

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which, upon vesting, entitle the holder to receive either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. DSUs vest immediately and are equivalent in value to a Cenovus common share on the date of redemption.

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSRs and PSUs are 1.41, 5.68 and 1.50 years, respectively. See the notes to the interim and annual Consolidated Financial Statements for details of our stock-based compensation plans.

Total Outstanding Common Shares and Stock-based Compensation Plans

(thousands of units)	September 30, 2013
Common Shares	**755,842**
Stock Options	
NSRs	**26,153**
TSARs	**7,627**
Cenovus Replacement TSARs (held by Encana Employees)	**2,191**
Encana Replacement TSARs (held by Cenovus Employees)	**4,023**
Other Stock-based Compensation Plans	
PSUs	**5,789**
DSUs	**1,182**

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, debt, future building leases, marketing agreements and capital commitments. 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. For further information, please see the notes to the interim and annual Consolidated Financial Statements.

Year-to-date, Cenovus entered into various firm transportation agreements totaling approximately $11 billion. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years, subsequent to the date of commencement, and will help align our future transportation requirements within our anticipated production growth.

In addition, Cenovus entered into an office lease agreement totaling approximately $1 billion over a 22 year term beginning upon completion of construction of the building expected to be late in 2017.

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 legal claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with our 2012 annual MD&A.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. Our exposure to liquidity risk, safety risk, transportation restrictions, capital project execution and operating risk, reserves replacement risk, environmental risk and regulatory risk has not changed substantially since December 31, 2012.

A description of the risk factors and uncertainties 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, 2012. The following provides an overview of our commodity price risk management activities and the effect of our risk management position on earnings for the three and nine months ending September 30, 2013.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are influenced by a number of factors including global and regional supply and demand, transportation constraints and alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

We manage our commodity price exposure through a combination of integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts.

The details of these financial instruments as at September 30, 2013 are disclosed in the notes to the interim Consolidated Financial Statements. The financial impact is summarized below.

Financial Impact of Risk Management Activities

	Three Months Ended September 30,					
	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(32)**	**22**	**(10)**	26	(189)	(163)
Natural Gas	**19**	**(15)**	**4**	65	(83)	(18)
Refining	**(22)**	**2**	**(20)**	6	(11)	(5)
Power	**2**	**(1)**	**1**	2	(10)	(8)
Gain (Loss) on Risk Management	**(33)**	**8**	**(25)**	99	(293)	(194)
Income Tax Expense (Recovery)	**(11)**	**3**	**(8)**	26	(75)	(49)
Gain (Loss) on Risk Management, after-tax	**(22)**	**5**	**(17)**	73	(218)	(145)

	Nine Months Ended September 30,					
	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**22**	**(147)**	**(125)**	26	102	128
Natural Gas	**46**	**(51)**	**(5)**	200	(144)	56
Refining	**(30)**	**1**	**(29)**	18	(3)	15
Power	**7**	**1**	**8**	-	(15)	(15)
Gain (Loss) on Risk Management	**45**	**(196)**	**(151)**	244	(60)	184
Income Tax Expense (Recovery)	**7**	**(49)**	**(42)**	64	(16)	48
Gain (Loss) on Risk Management, after-tax	**38**	**(147)**	**(109)**	180	(44)	136

In the three months ended September 30, 2013, management of commodity price risk resulted in realized losses on crude oil financial instruments consistent with the average benchmark prices exceeding our contract prices. We recognized realized gains on our natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recognized unrealized gains on our crude oil financial instruments as a result of the decrease in forward commodity prices, the widening of forward light/heavy differentials, compared to prices at the end of the prior quarter, and the realization of settled positions. Management of our natural gas financial instruments resulted in unrealized losses as a result of the increase in forward commodity prices and the realization of settled positions.

For the nine months ended September 30, 2013, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments consistent with our contract prices exceeding the average benchmark price. We recognized unrealized losses on our crude oil and natural gas financial instruments as a result of the increase in forward commodity prices, the narrowing of forward light/heavy differentials, compared to prices at the end of the prior year, and the realization of settled positions.

Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding our critical accounting judgments, estimates and accounting policies the following should be read in conjunction with our 2012 annual MD&A.

We are required to make judgments, estimates and assumptions 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 details 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, 2012.

Critical Accounting Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in Cenovus's annual and interim Consolidated Financial Statements and accompanying notes. On January 1, 2013, as required, we adopted the standards related to joint arrangements, consolidations and associates, which required critical judgments. See discussion below under Joint Arrangements, Consolidation, Associates and Disclosures for details. Further information on our critical accounting judgments in applying accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty for the nine months of 2013. Further information on our key sources of estimation uncertainty can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Changes in Accounting Policies

Joint Arrangements, Consolidation, Associates and Disclosures

As disclosed in the Consolidated Financial Statements, effective January 1, 2013, Cenovus adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to International Accounting Standard ("IAS") 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Cenovus performed a comprehensive review of its interests in other entities and identified two individually significant interests, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), for which it shares joint control. Previously, Cenovus accounted for these jointly controlled entities using proportionate consolidation.

Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of Cenovus's accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements have been classified as joint operations under IFRS 11 and Cenovus's share of the assets, liabilities, revenues and expenses have been recognized in our interim Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, Cenovus considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially, on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

There has been no impact on the recognized assets, liabilities and comprehensive income of Cenovus with the application of these standards.

Employee Benefits

As disclosed in the Consolidated Financial Statements, effective January 1, 2013, Cenovus adopted, as required, by IAS 19 "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). Cenovus applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

The amendments require the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor approach' previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through other comprehensive income. In addition, Cenovus replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in net earnings.

IAS 19R requires termination benefits to be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs. This requirement had no impact on the Consolidated Financial Statements.

The impact on adoption of IAS 19R was not material and is shown below:

Consolidated Statements of Earnings and Comprehensive Income

($ millions)	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012	Year Ended December 31, 2012
Increase (Decrease) due to:			
Net Earnings	-	1	2
Other Comprehensive Income	(1)	(3)	(4)

Consolidated Balance Sheets

($ millions)	December 31, 2012	January 1, 2012
Increase (Decrease) due to:		
Net Defined Benefit Liability (1)	32	30
Deferred Income Taxes	(8)	(8)
Shareholders' Equity	(24)	(22)

(1) *Composed of the defined benefit pension and other post-employment benefit plans.*

Fair Value Measurement

Effective January 1, 2013, Cenovus adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, Cenovus applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within other comprehensive income ("OCI") to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to other comprehensive income or comprehensive income.

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, Cenovus complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. Refer to the interim Consolidated Financial Statements for the additional disclosure. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

Future Accounting Pronouncements

In May 2013, the IASB released an amendment to IAS 36 "*Impairment of Assets*". This amendment requires entities to disclose the recoverable amount of an impaired Cash Generating Unit ("CGU"). The amendment is effective January 1, 2014. Early adoption is permitted.

A description of additional standards and interpretations that will be adopted by Cenovus in future periods can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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. Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes.

In September 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year, and also to the Dow Jones Sustainability North America Index for the fourth consecutive year. In June 2013, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada. Corporate Knights also named Cenovus to their Global 100 ranking for the first time as announced during the World Economic Forum in Davos. These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

In July 2013, we published our 2012 CR report, with highlights including our investments in innovation and research, local and Aboriginal spending in our operating areas, advancements made in minimizing our environmental impacts, long-term agreements signed with Aboriginal communities, and our involvement with and investments in charities and non-profit organizations. Our CR policy and CR report are available on our website at cenovus.com.

In October 2013, we were recently named to the Canada 200 Climate Disclosure Leadership Index for the fourth consecutive year. The index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions.

OUTLOOK

We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and net crude oil production of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be enabled by technology, innovation and continued respect for the health and safety of our employees, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

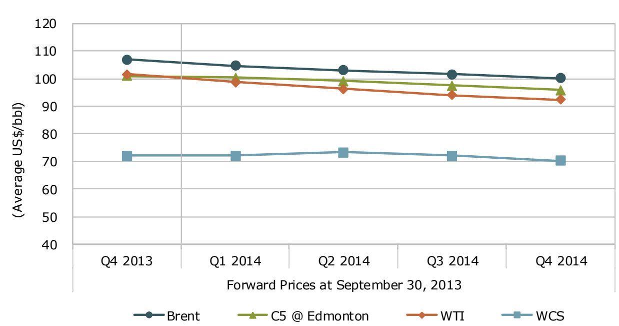
The outlook commentary herein is focused on the next six to 18 months. We also direct our readers to review the guidance for 2013 that we published on our website, cenovus.com, in connection with our news release.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

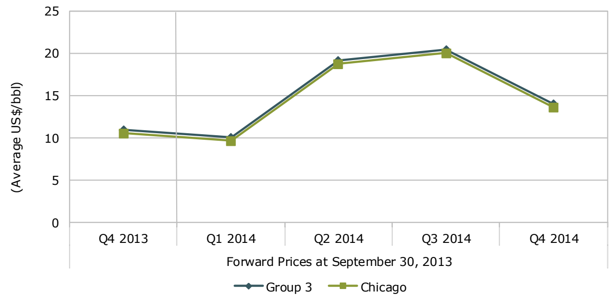
- The general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth and production interruptions. Indicators suggest a continued gradual improvement in demand growth from both U.S. and Chinese markets. Global supply disruptions are difficult to predict, however, political instability which is the root cause of supply outages is unlikely to be resolved quickly;
- The Brent-WTI differential is expected to remain near recent levels as modest firming of WTI prices relative to U.S. Gulf Coast prices should be offset by weakening Gulf Coast prices relative to Brent;
- We expect WCS prices to weaken relative to U.S. Gulf Coast and WTI pricing. With several new oil sands projects starting up over the coming months, inland heavy crude oil supply should increase and push the pipeline system back into a constrained situation until significant new rail capacity is added toward the end of the year and the first quarter of 2014;

Crude Oil Benchmarks – Forward Prices



- Refining crack spreads can be expected to remain weak as we move into the historically softer winter months. The strong Chicago-WTI crack spreads witnessed over the past two to three years due to inland crude congestion are not expected to reappear in the near future as the Keystone XL Gulf Coast portion of the pipeline will solidify the excess pipeline capacity that has recently developed from the Cushing area to the Gulf Coast; and
- Natural gas prices are expected to gradually firm toward the US$4 per MMBtu level through the end of the year but will be affected by winter temperatures. The sharp reduction in drilling activity over the past couple of years has finally resulted in a flattening of supply growth. With continued growth in demand, some additional firming in prices will be required to encourage more producer activity to keep supply growth in line with demand growth.

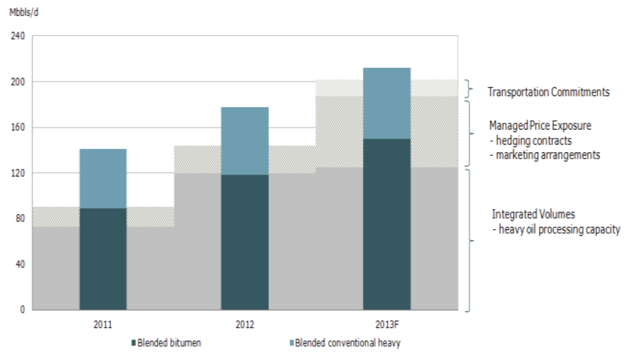
Refining 3-2-1 Crack Spread Benchmarks – Forward Prices



While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Crude Oil Congestion



(1) Expected net production capacity.

Update on Key Strategic Priorities

Market Access

We are focused on near and mid-term strategies to broaden market access for Canadian oil. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We anticipate increasing our rail shipping capacity for oil to approximately 10,000 barrels per day by the end of 2013, subject to favorable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil. During the nine months of 2013, we transported approximately 6,000 barrels per day by rail, allowing us to realize higher prices on our crude oil and diversify our customer base. We also entered into $11 billion of new pipeline commitments (some of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth.

Long-term Cost Structures

We have a track record of cost efficiency. To continue to meet our business plan, we must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we have a number of opportunities to improve our cost efficiency by further leveraging our supply chain management to improve capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within the industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section in our annual MD&A.

ADVISORY

Forward-looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "projected", "objectives", "may", "strategy" 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, projections contained in our 2013 guidance, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, broadening market access, improving cost structure, expected reserves and 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 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 disclosed in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates 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.

We updated our guidance for 2013, published on our website, cenovus.com, and provided details of the events and circumstances that led to the update in our July 24, 2013 and October 24, 2013 news release.

For the period 2014 to 2023, assumptions include: Brent US$100.00-US$110.00; WTI of US$96.00-US$106.00/bbl; Western Canada Select of C$71.00-C$91.00/bbl; NYMEX of US$4.50-US$4.75/MMBtu; AECO of C$3.89-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$15.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 780 million.

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; the 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, including sufficient crude-by-rail or other alternate 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 interim 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 risk management, see "Risk Management" in this MD&A and in our MD&A for the year ended December 31, 2012. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2012, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

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

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
		GJ	Gigajoule
		CBM	Coal Bed Methane

Other	
TM	Trademark of Cenovus Energy Inc.