MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED MARCH 31, 2013

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., ("we", "our", "Cenovus", or the "Company") dated April 23, 2013, should be read in conjunction with our March 31, 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 Operating Results, Financial Results and 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 March 31, 2013, we had a market capitalization of approximately $24 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 in the first quarter of 2013 was in excess of 180,000 barrels per day, our average natural gas production was 545 MMcf per day and our refinery operations produced an average of 439,000 barrels per day of refined product.

Our Strategy

Our strategy is to create long-term value for our shareholders 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:

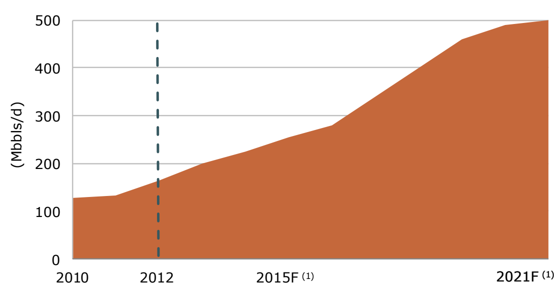
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the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

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of 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 400,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 500,000 barrels per day by the end of 2021. We are focusing on the development of our substantial crude oil resources predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows 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 capacity.

Oil Sands

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

	Ownership Interest (percent)	Q1 2013 Net Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects			
Foster Creek	50	55,996	310,000
Christina Lake	50	44,351	300,000
Narrows Lake	50	-	130,000
Emerging Projects			
Grand Rapids	100	-	180,000
Telephone Lake	100	-	300,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca Region of northeastern Alberta. In addition to current production, expansion work is underway at phases F, G and H at Foster Creek with added production capacity from phase F expected in the third quarter of 2014. Christina Lake is anticipating production from phase E in the third quarter of 2013, with expansion work currently underway for phases F and G. In the first quarter of 2013, we submitted joint applications and environmental impact assessments ("EIAs") for Foster Creek phase J and Christina Lake phase H. We anticipate receiving regulatory approval for Foster Creek in the first quarter of 2015 and Christina Lake 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 in December 2012 for phase A. Site preparation and procurement is underway and we anticipate first production in 2017.

Two of our emerging projects are Grand Rapids and Telephone Lake. 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 commercial SAGD operation. We anticipate regulatory approval in the fourth quarter of 2013. Our Telephone Lake property is located within the Borealis Region. In December 2011, we submitted a revised joint application and EIA due to an increase in the project development area. We anticipate receiving regulatory approval in 2014.

Also located within the Athabasca Region, is our wholly owned Pelican Lake property. Pelican Lake produces heavy oil using polymer flood technology and has expected ultimate production capacity of 55,000 barrels per day.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows, which 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.

	Three Months Ended March 31, 2013	
($ millions)	Crude Oil and NGLs	Natural Gas
Operating Cash Flow	235	111
Capital Investment	190	8
Operating Cash Flow in Excess of Related Capital Investment	**45**	**103**

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

Refining and Marketing

Our operations include 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)	Q1 2013 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)	Three Months Ended March 31, 2013
Operating Cash Flow	528
Capital Investment	25
Operating Cash Flow in Excess of Related Capital Investment	**503**

Technology and Environment

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

Dividend

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

Net Asset Value

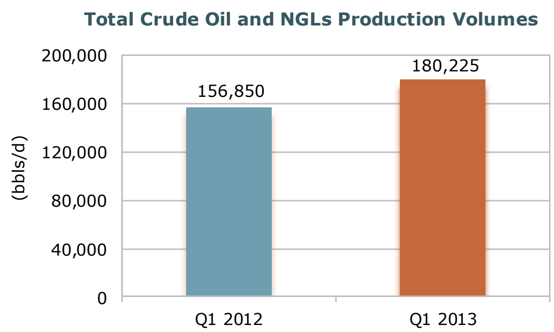
We measure our success in a number of ways with a key measure being growth in net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

OPERATING AND FINANCIAL HIGHLIGHTS

The first quarter of 2013 highlights the strength of our integrated approach. Despite continued volatility in crude oil prices, Operating Cash Flow and Cash Flow increased from 2012, as a result of strong refining margins and increases in crude oil production. During the first quarter of 2013, the West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differential widened 49 percent, averaging US$31.96 per barrel (2012 – US$21.42 per barrel), and the Brent-WTI differential widened by 19 percent. While upstream operations are negatively impacted by wider WTI-WCS differentials, our refining operations are able to capture value from both the WTI-WCS differential for Canadian crude oil in lower feedstock costs and the Brent-WTI differential in higher selling prices for the sale of refined products.

Operational Results for the First Quarter of 2013

In the first quarter, crude oil production from our Oil Sands segment averaged 124,034 barrels per day, an increase of 21 percent compared to 2012. Christina Lake, phase D, our ninth SAGD expansion phase, began producing in the third quarter of 2012 and the facility exceeded gross nameplate capacity of 98,000 barrels per day, achieving a new single day production high in the quarter of 100,176 gross barrels per day. Pelican Lake production increased while Foster Creek production remained relatively flat.



Within our Conventional segment, crude oil and NGLs production averaged 56,191 barrels per day, an increase of four percent, as a result of successful well performance in Alberta. Alberta crude oil production increased nine percent to an average of 32,047 barrels per day.

Our refining operations produced 439,000 barrels per day of refined products, a decrease of about 26,000 barrels per day, or six percent, due to planned maintenance activities in March. We processed an average of 416,000 (Q1 2012 – 445,000) barrels per day of crude oil, of which 197,000 barrels per day was heavy crude oil (Q1 2012 – 199,000). Despite decreases in refined product volumes, strong refining margins, resulting from discounted crude oil feedstock costs and higher market crack spreads, generated strong Operating Cash Flow.

Other significant operational results in the first quarter, as compared to 2012, include:

- Christina Lake production averaging 44,351 barrels per day, an increase of 79 percent, as phase C reached full capacity in the second quarter of 2012 and the start-up of phase D in the third quarter of 2012;
- Foster Creek production averaging 55,996 barrels per day, a decrease of two percent, as a higher than usual number of wells came off production as a result of downhole mechanical issues;
- Pelican Lake production averaging 23,687 barrels per day, an increase of 14 percent as a result of our infill drilling and polymer flood program;
- Natural gas production declining 14 percent to an average of 545 MMcf per day, primarily due to expected natural declines;
- Completing planned refinery maintenance; and
- Increasing our access to new markets with more volumes of crude oil being shipped on a pipeline to the West Coast and approximately 6,000 barrels per day transported by rail to the East Coast and the U.S.

Financial Results for the First Quarter of 2013

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.

In the first quarter, our integrated approach allowed us to mitigate the impact of wider WTI-WCS price differentials which resulted in decreased Canadian crude oil prices, with continued high refining margins and strong crude oil production, resulting in total Operating Cash Flow of $1,211 million, a 12 percent increase, and Cash Flow of $971 million, a seven percent increase. Operating Earnings were $391 million, a 15 percent increase, primarily due to higher cash flow, while net earnings declined 60 percent to $171 million, primarily due to unrealized risk management and foreign exchange losses, as compared to gains in 2012. We paid a quarterly dividend of $0.242 per share (2012 – $0.22 per share), an increase of 10 percent, demonstrating our continuing commitment to pay a strong and sustainable dividend as part of delivering total shareholder return.

Other financial highlights for the first quarter, as compared to 2012, include:

Revenues

Revenues of $4,319 million, decreasing $245 million or five percent as a result of:
- Our crude oil average sales price (excluding financial hedging) decreasing 27 percent to $54.02 per barrel;
- Refining and Marketing revenues decreasing $46 million due to planned refinery maintenance activities reducing refined product output; and
- A decrease in natural gas sales volumes of 14 percent primarily due to expected natural declines in production.

Partially offsetting these decreases in revenues were:
- Crude oil sales volumes increasing 12 percent;
- Royalties decreasing by 52 percent primarily due to lower crude oil prices and higher capital investment;
- Increased condensate volumes used for blending, partially offset by decreased condensate prices; and
- Our natural gas average sales price (excluding financial hedging) increasing 30 percent to $3.25 per Mcf.

Operating Cash Flow

Operating Cash Flow of $1,211 million, increasing $126 million or 12 percent due to:
- Operating Cash Flow from our Refining and Marketing segment increasing $261 million due to lower refinery feedstock costs, partially offset by a decrease in refined product output as a result of planned maintenance activities.

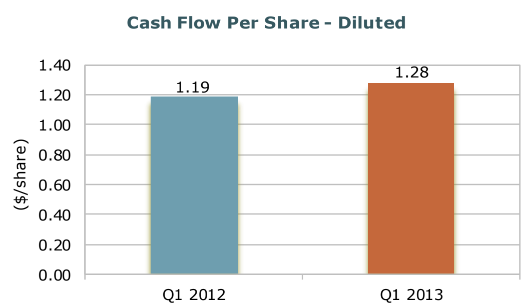
Partially offset by a decline in upstream operating cash flow of $135 million resulting from:
- A reduction in upstream revenues as a result of average crude oil sales price decreases, partially offset by production volume increases and a reduction in royalties; and
- Higher upstream operating costs of $21 million, primarily as a result of increased production at Christina Lake, rising fuel costs consistent with the increase in the benchmark AECO price, higher chemical costs related to the expanded polymer flood and increased workforce costs related to our phased expansions. This was partially offset by lower repairs and maintenance costs.

Cash Flow

Cash Flow of $971 million, increasing $67 million or seven percent due to an increase in Operating Cash Flow, partially offset by higher general and administrative expenses, excluding non-cash long-term incentive charges.

Operating Earnings

Operating Earnings of $391 million, increasing $51 million, as a result of increases in Cash Flow offset by changes in non-cash items.



Net Earnings

Net earnings of $171 million, decreasing $255 million or 60 percent, primarily as a result of unrealized risk management and foreign exchange losses in the quarter compared to gains in 2012.

Capital Investment

Capital investment of $915 million was consistent with 2012, increasing two percent, primarily due to phase expansions at our oil sands operations.

OPERATING RESULTS

Crude Oil and NGLs Production Volumes

(barrels per day)	Three Months Ended March 31, 2013	Percent Change	2012
Oil Sands			
Foster Creek	**55,996**	**(2)%**	57,214
Christina Lake	**44,351**	**79%**	24,733
Pelican Lake	**23,687**	**14%**	20,730
Conventional			
Heavy Oil	**16,712**	**1%**	16,624
Light and Medium Oil	**38,508**	**6%**	36,411
NGLs [(1)]	**971**	**(15)%**	1,138
Total Crude Oil and NGLs Production	**180,225**	**15%**	156,850

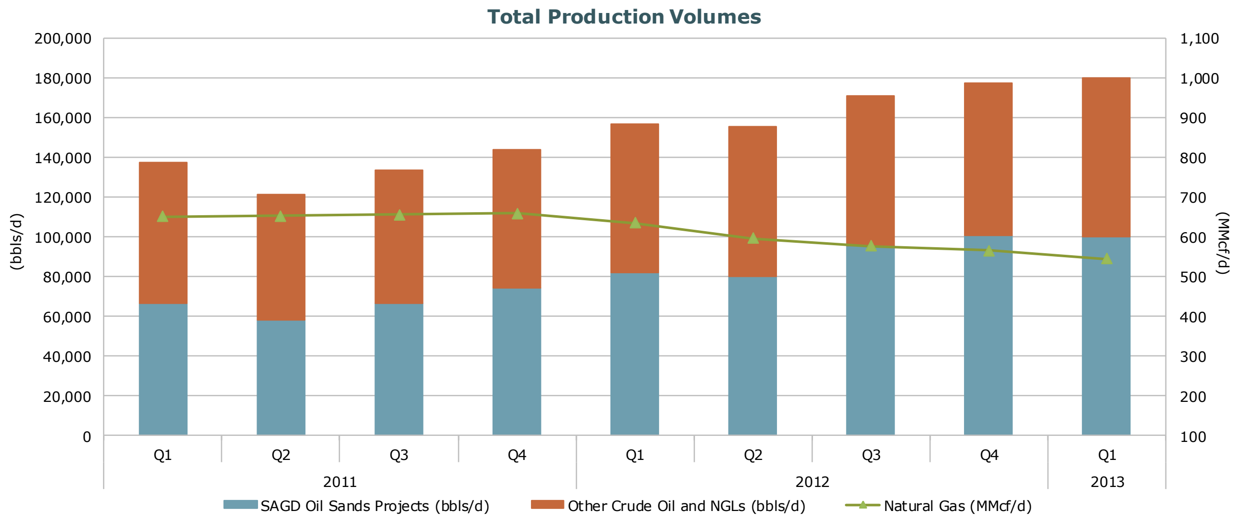
(1) NGLs include condensate volumes.

In the first quarter, our crude oil and NGLs production increased as Christina Lake phase C reached full capacity in the second quarter of 2012 and the start-up of phase D in the third quarter of 2012. Rising production at Pelican Lake from our infill drilling and polymer flood program and increased light and medium crude oil production as a result of better horizontal well performance in Alberta also increased production. The increases were slightly offset by decreases in production at Foster Creek as during the quarter a higher than usual number of wells came off production as a result of downhole mechanical issues.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended March 31, 2013	2012
Conventional	**525**	595
Oil Sands	**20**	41
	545	636

In the first quarter, our natural gas production declined compared to 2012, as expected, in line with our decision to direct capital investment to our oil properties. In the low commodity price environment, we have chosen to manage natural gas capital spending for the past several years focusing on high rate of return projects.



Operating Netbacks

	Three Months Ended March 31,			
	2013		2012	
	Crude Oil ($/bbl)	**Natural Gas ($/Mcf)**	Crude Oil ($/bbl)	Natural Gas ($/Mcf)
Price [1]	**54.02**	**3.25**	74.22	2.50
Royalties	**3.43**	**0.05**	8.10	0.06
Transportation and Blending [1]	**2.82**	**0.15**	2.83	0.13
Operating Expenses	**15.27**	**1.14**	14.81	1.08
Production and Mineral Taxes	**0.56**	**0.03**	0.59	0.02
Netback Excluding Realized Risk Management	**31.94**	**1.88**	47.89	1.21
Realized Risk Management Gain (Loss)	**2.64**	**0.39**	(1.68)	1.03
Netback Including Realized Risk Management	**34.58**	**2.27**	46.21	2.24

(1) Heavy crude oil is mixed with purchased condensate. The crude oil price and transportation and blending costs exclude the impact of condensate purchases of $31.26 per barrel (2012 – $30.36 per barrel).

In the first quarter, our average netback for crude oil, excluding realized risk management gains and losses, decreased $15.95 per barrel from 2012, primarily due to lower sales prices. Sales prices decreased in the first quarter, consistent with significantly lower benchmark prices, as the average WTI–WCS differential widened to US$31.96 per barrel compared to US$21.42 per barrel in 2012. The price decreases were partially offset by a reduction in royalties at Foster Creek.

Our average netback for natural gas, excluding realized risk management gains and losses, increased $0.67 per Mcf in the first quarter compared to 2012, predominantly from 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 March 31,		
	2013	**Percent Change**	2012
Crude Oil Runs (Mbbls/d)	**416**	**(7)%**	445
Heavy Oil	**197**	**(1)%**	199
Crude Utilization (percent)	**91**	**(7)%**	98
Refined Product (Mbbls/d)	**439**	**(6)%**	465

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

Planned maintenance activities during the first quarter lowered crude oil runs, utilization rates and refined product output. Despite these decreases, our heavy oil processed in the first quarter remained consistent with 2012, reflecting our ability to process a greater proportion of heavy oil feedstock and the optimization of our total crude input slate during a period of lower feedstock costs.

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)

	Q1 2013	Q4 2012	Q1 2012
Crude Oil Prices (US$/bbl)			
Brent Futures			
Average	**112.64**	110.13	118.45
End of Period	**110.02**	111.11	122.88
WTI			
Average	**94.36**	88.23	103.03
End of Period	**97.23**	91.82	103.02
Average Differential Brent-WTI	**18.28**	21.90	15.42
WCS			
Average	**62.40**	70.12	81.61
End of Period	**82.71**	59.16	79.52
Average Differential WTI-WCS	**31.96**	18.11	21.42
Condensate (C5 @ Edmonton) Average	**107.23**	98.14	110.16
Average Differential WTI-Condensate (Premium)	**(12.87)**	(9.91)	(7.13)
Refining Margin 3-2-1 Average Crack Spreads (2) (US$/bbl)			
Chicago	**27.53**	28.18	19.00
Midwest Combined ("Group 3")	**27.93**	28.49	21.50
Natural Gas Average Prices			
AECO ($/GJ)	**2.92**	2.90	2.39
NYMEX (US$/MMBtu)	**3.34**	3.40	2.74
Basis Differential NYMEX-AECO (US$/MMBtu)	**0.27**	0.31	0.21
Foreign Exchange Rate (US$ per C$1)			
Average	**0.992**	1.009	0.999

(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.*

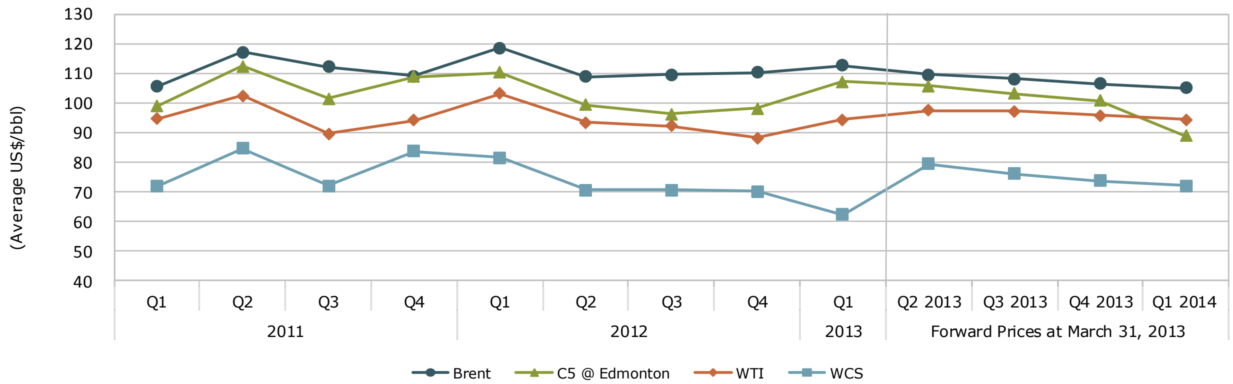
(2) *The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and a last in, first out accounting basis.*

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. In the first quarter, the average price of Brent crude oil was slightly lower than the same period in 2012, averaging near US$113 per barrel, mostly due to reduced worries that planned economic sanctions and potential military action against Iran could potentially reduce Iranian crude oil production. Partially mitigating the price decrease were global demand increases that outpaced supply from countries that are not members in the Organization of the Petroleum Exporting Countries.

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. WTI has been trading at a significant discount to Brent prices for the past two years as inland crude oil supply growth has strained pipeline takeaway capacity from inland crude oil markets. These discounts widened in the first quarter compared to the same period in 2012, as extended refinery outages in the U.S. Midwest lowered demand for inland light crude oil, and restrictions to flows on the pipeline from Cushing to the U.S. Gulf Coast markets created congestion. Towards the end of the quarter, discounts started to ease in anticipation of improvements in the pipeline flows moving crude oil volumes from the Cushing-area market.

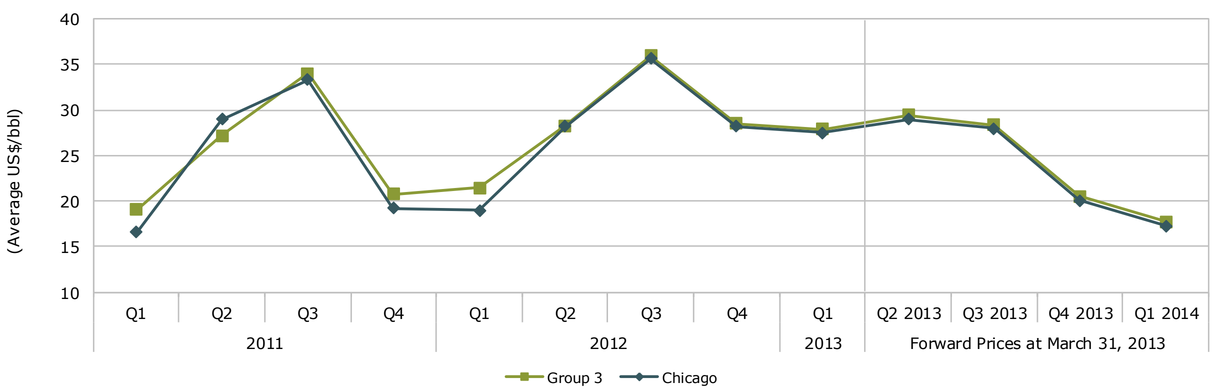
WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential widened significantly in the first quarter, as increased supply from resolution of outages, the anticipation of additional production from northern Alberta and increased seasonal condensate requirements further aggravated an already congested transportation network out of the Western Canadian Sedimentary Basin ("WCSB"). Near the end of the quarter, differentials narrowed due to delays in the anticipated northern Alberta production and new outages in heavy crude oil supply.



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 widened by US$5.74 per barrel in the first quarter, compared to 2012, despite weakening Gulf Coast condensate differentials. This resulted from increased condensate premiums at Edmonton due to limited transportation options from the Gulf Coast to Edmonton. Also contributing to the wider WTI-Condensate differentials was weakness in WTI pricing.

Refining 3-2-1 Crack Spread Benchmarks

Average crack spreads in the U.S. inland Chicago and Group 3 markets for the first quarter rose from the same period in 2012 due to increased inland North American crude oil (WTI) discounts and extended outages at a number of U.S. Midwest refineries.



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

Other Benchmarks

Average natural gas prices in the first quarter increased as gas in storage dropped significantly from the same period in 2012 due to stronger demand and falling supply. The increase in demand is primarily due to the surge in residential and commercial demand with more normal weather in 2013, compared to milder temperatures that occured in the first quarter of 2012. Although gas-fired power generation has declined significantly from 2012, it remains strong in comparison to previous years.

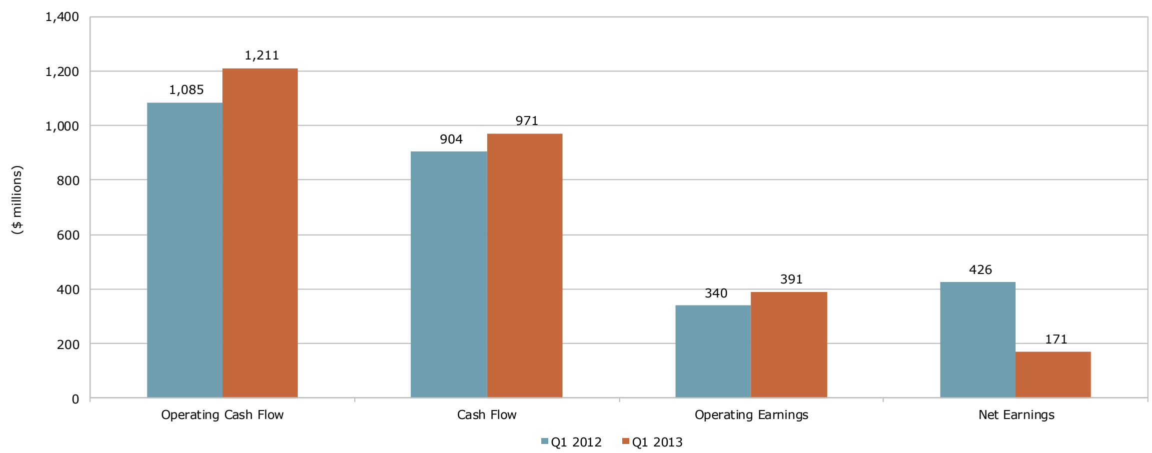
A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also inflates our current period's reported refining capital investment. During the first quarter, the Canadian dollar weakened slightly relative to the U.S. dollar, compared to the same period last year, but remained close to parity.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

Operating Cash Flow, Cash Flow, Operating Earnings and Net Earnings



($ millions, except per share amounts)	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1
Revenues	**4,319**	3,724	4,340	4,214	4,564	4,329	3,858	4,009	3,500
Operating Cash Flow (1)	**1,211**	963	1,310	1,078	1,085	1,019	945	1,064	834
Cash Flow (1)	**971**	697	1,117	925	904	851	793	939	693
Per Share – Diluted	**1.28**	0.92	1.47	1.22	1.19	1.12	1.05	1.24	0.91
Operating Earnings (1) (2)	**391**	(188)	432	284	340	332	303	395	209
Per Share – Diluted (2)	**0.52**	(0.25)	0.57	0.37	0.45	0.44	0.40	0.52	0.28
Net Earnings (2)	**171**	(117)	289	397	426	266	510	655	47
Per Share – Basic (2)	**0.23**	(0.15)	0.38	0.53	0.56	0.35	0.68	0.87	0.06
Per Share – Diluted (2)	**0.23**	(0.15)	0.38	0.52	0.56	0.35	0.67	0.86	0.06
Capital Investment (3)	**915**	978	830	660	900	903	631	476	713
Cash Dividends	**184**	167	166	166	166	151	150	151	151
Per Share	**0.242**	0.22	0.22	0.22	0.22	0.20	0.20	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

($ millions)	
Revenues for the Three Months Ended March 31, 2012	**4,564**
Increase (Decrease) due to:	
Oil Sands	**(50)**
Conventional	**(27)**
Refining and Marketing	**(46)**
Corporate and Eliminations	**(122)**
Revenues for the Three Months Ended March 31, 2013	**4,319**

Upstream revenues declined five percent due to lower realized crude oil and condensate prices and lower natural gas production, partially offset by increased crude oil production and condensate volumes, reduced royalties, and higher realized natural gas prices. Revenues generated by the Refining and Marketing segment decreased by two percent due to a decline in refined product output as a result of planned maintenance activities. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility partially offset decreases in refining revenues.

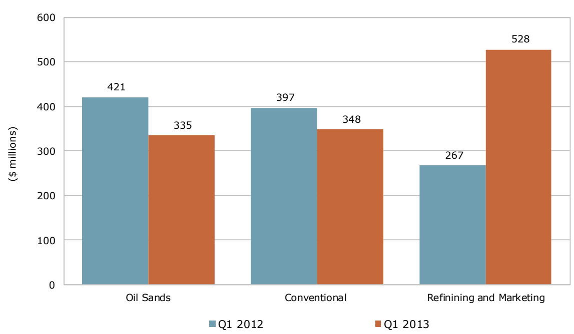
Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Cash Flow

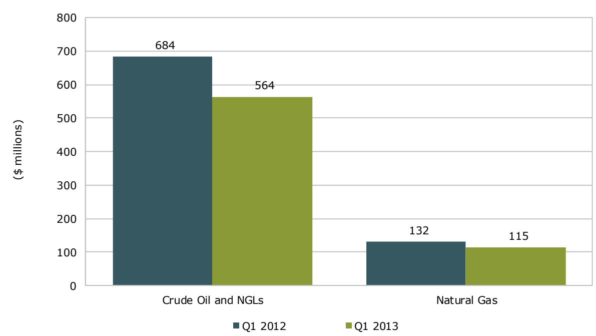
Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities. Items within the Corporate and Eliminations segment are excluded in the calculation of Operating Cash Flow.

	Three Months Ended March 31,	
($ millions)	**2013**	2012
Revenues	**4,441**	4,564
(Add Back) Deduct:		
Purchased Product	**2,277**	2,589
Transportation and Blending	**558**	494
Operating Expenses	**443**	415
Production and Mineral Taxes	**10**	10
Realized (Gain) Loss on Risk Management Activities	**(58)**	(29)
Operating Cash Flow	**1,211**	1,085

Operating Cash Flow by Segment



Operating Cash Flow by Upstream Product

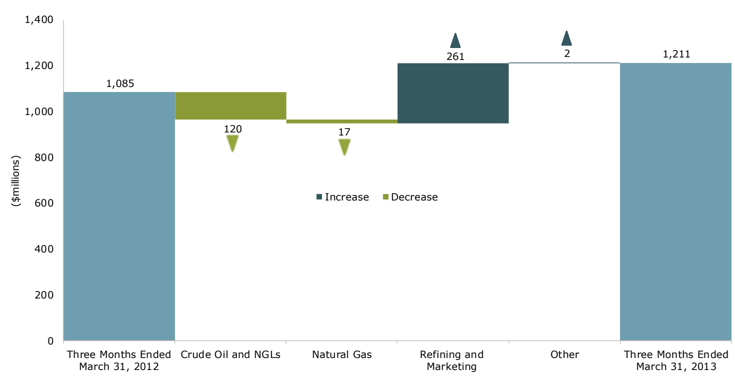


Operating Cash Flow Variance for the Three Months Ended March 31, 2013 compared to March 31, 2012

During the first quarter, Operating Cash Flow increased $126 million or 12 percent as compared to 2012.

Operating Cash Flow from crude oil and NGLs production decreased $120 million (18 percent) due to lower average crude oil sales prices partially offset by production volume increases.

Operating Cash Flow from natural gas declined $17 million (13 percent), due to reduced production volumes from expected natural declines, partially offset by increased natural gas sales prices.



Refining and Marketing Operating Cash Flow rose $261 million (98 percent) due to lower refinery feedstock costs, partially offset by reduced refinery output due to planned maintenance activities.

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.

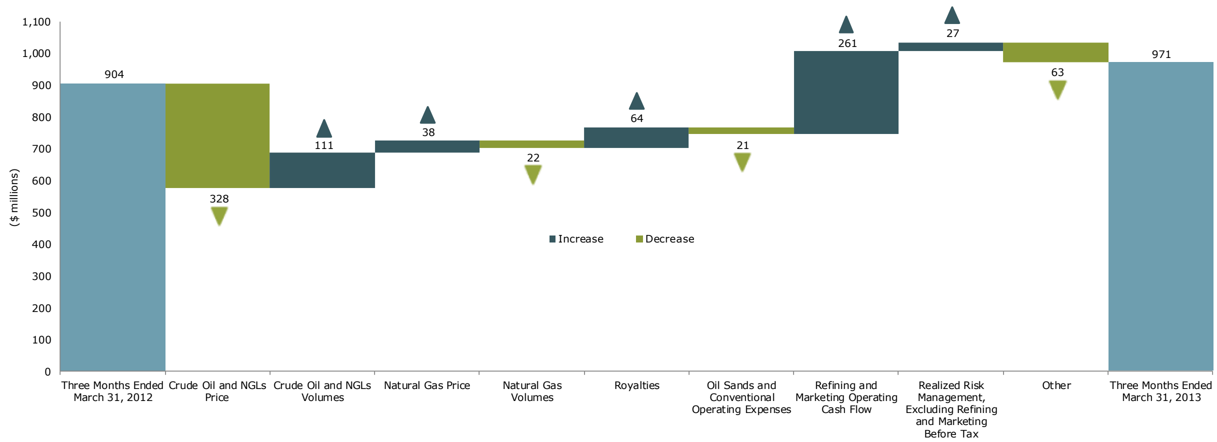
	Three Months Ended March 31,	
($ millions)	**2013**	2012
Cash From Operating Activities	**895**	665
(Add Back) Deduct:		
Net Change in Other Assets and Liabilities	**(34)**	(32)
Net Change in Non-Cash Working Capital	**(42)**	(207)
Cash Flow	**971**	904

Cash Flow Variance for the Three Months Ended March 31, 2013 compared to March 31, 2012

Our integrated approach enables us to capture the full value chain from production to refined products. This was demonstrated in the quarter as the reduction in our realized crude oil price, from widening light/heavy differentials, decreased our upstream Operating Cash Flow but resulted in higher refining Operating Cash Flow through lower feedstock costs.

In the first quarter, our Cash Flow increased $67 million, or seven percent, primarily due to:

- An increase in Operating Cash Flow from Refining and Marketing of $261 million due to lower refinery feedstock costs, partially offset by reduced refined product output as a result of planned maintenance activities;
- A 12 percent increase in our crude oil sales volumes;
- A decrease in royalties of $64 million primarily at Foster Creek as a result of decreased crude oil prices and increased capital, and in our Conventional segment, also as a result of declines in crude oil prices;
- A 30 percent increase in our average sales price of natural gas to $3.25 per Mcf; and
- Realized risk management gains before tax, excluding Refining and Marketing, of $62 million compared to gains of $35 million in 2012.



The increase in our Cash Flow was partially offset by:

- A 27 percent decrease in our average sales price of crude oil to $54.02 per barrel;
- An increase in general and administrative expense, excluding non-cash long-term incentive costs;
- A 14 percent decline in natural gas production, primarily as a result of expected natural declines; and
- An increase in upstream operating expenses of $21 million, partially from higher crude oil production at Christina Lake and Pelican Lake. On a per unit basis, crude oil operating costs increased to $15.27 per barrel primarily due to increases in fuel costs consistent with the increase in the benchmark AECO price.

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.

Operating Earnings

($ millions)	Three Months Ended March 31, 2013	2012
Net Earnings	**171**	426
Add Back (Deduct):		
Unrealized Risk Management (Gain) Loss, after-tax (1)	**173**	(48)
Non-operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2)	**47**	(38)
Operating Earnings	**391**	340

(1) *The unrealized risk management gain (loss), after-tax includes the reversal of unrealized gain (loss) recognized in prior periods.*
(2) *After-tax unrealized foreign exchange gain (loss) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gain (loss) 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 increased $51 million or 15 percent from 2012 due to an increase in Cash Flow, as previously discussed, and a non-cash long term incentive recovery in 2013 compared to an expense in 2012, partially offset by higher depreciation, depletion and amortization ("DD&A") and higher deferred tax expense.

Net Earnings Variance

($ millions)	
Net Earnings for the Three Months Ended March 31, 2012	**426**
Increase (Decrease) due to:	
Operating Cash Flow	**126**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss), after-tax	**(221)**
Unrealized Foreign Exchange Gain (Loss)	**(81)**
Expenses (1)	**4**
Depreciation, Depletion and Amortization	**(55)**
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**(28)**
Net Earnings for the Three Months Ended March 31, 2013	**171**

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

In the first quarter, our net earnings decreased $255 million or 60 percent, primarily as a result of unrealized risk management losses, after tax, of $173 million, compared to gains of $48 million in 2012. Other significant factors that impacted our net earnings for the quarter include:

- Unrealized foreign exchange losses of $50 million, compared to gains of $31 million in 2012;
- An increase of $55 million in DD&A due to higher crude oil production and increased DD&A rates from higher future development costs associated with total proved reserves partially offset by decreased natural gas production; and
- Increased Operating Cash Flow as previously discussed.

Net Capital Investment

($ millions)	Three Months Ended March 31, 2013	2012
Oil Sands	**677**	636
Conventional	**198**	231
Refining and Marketing	**25**	(2)
Corporate	**15**	35
Capital Investment	**915**	900
Acquisitions	**3**	8
Divestitures	**(1)**	(66)
Net Capital Investment (1)	**917**	842

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

Oil Sands capital investment in the first quarter was focused on the development of the expansion phases at Foster Creek and Christina Lake and facility expansion and infill drilling activities related to our Pelican Lake polymer flood. In addition, capital investment at Narrows Lake focused on site preparation and procurement for phase A subsequent to receipt of partner approval in December 2012. Construction of the phase A plant is scheduled to start in the third quarter of 2013. Capital investment includes the drilling of 312 gross stratigraphic test wells. The result of these stratigraphic test wells will be used primarily to support the expansion and development of our Oil Sands projects.

Conventional capital investment was centered on drilling, completion and recompletion programs as well as work on facilities in Saskatchewan and Alberta.

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

Included in our capital investment is spending on technology development. Our teams look for ways to either improve existing technology or pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas.

Capital investment in our Corporate and Eliminations segment was for information technology and tenant improvements to new office space.

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 allow us to be financially resilient in times of lower cash flows.

($ millions)	Three Months Ended March 31, 2013	2012
Cash Flow	**971**	904
Capital Investment (Committed and Growth)	**915**	900
Free Cash Flow [1]	**56**	4
Dividends Paid	**184**	166
	(128)	(162)

(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 500,000 barrels per day. In order to meet these project targets, we anticipate capital expenditures to average between $3.0 and $3.5 billion a year. 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 March 31, 2013, we had cash and cash equivalents of approximately $978 million 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 March 31, 2013	2012
Oil Sands	**986**	1,036
Conventional	**509**	536
Refining and Marketing	**2,946**	2,992
Corporate and Eliminations	**(122)**	-
	4,319	4,564

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 Grand Rapids and Telephone Lake. 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 first quarter, compared to 2012 include:

- Christina Lake production increasing 79 percent, to an average of 44,351 barrels per day as phase C reached full capacity in the second quarter of 2012 and the start-up of phase D in the third quarter of 2012;
- Foster Creek production averaging 55,996 barrels per day, a decrease of two percent, as a higher than usual number of wells came off production as a result of downhole mechanical issues;
- Filing joint applications and EIAs for Foster Creek phase J and Christina Lake phase H;
- Successfully completing a winter stratigraphic test well program with 312 gross wells drilled to further progress our Oil Sands projects; and
- Successful operation of the dewatering pilot at Telephone Lake.

Oil Sands – Crude Oil

Financial Results

($ millions)	Three Months Ended March 31, 2013	2012
Gross Sales	**995**	1,087
Less: Royalties	**21**	65
Revenues	**974**	1,022
Expenses		
Transportation and Blending	**511**	449
Operating	**163**	138
(Gain) Loss on Risk Management	**(29)**	18
Operating Cash Flow	**329**	417
Capital Investment	**676**	631
Operating Cash Flow Deficiency net of Related Capital Investment	**(347)**	(214)

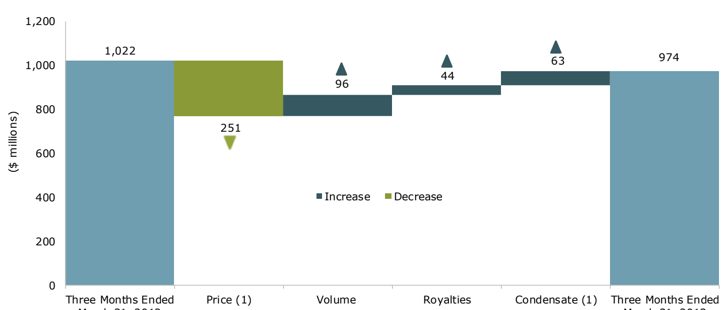
Capital expenditures in excess of Operating Cash Flow for the Oil Sands segment are funded through Operating Cash Flow generated by our conventional and refining operations.

Revenues

Pricing

In the first quarter, our average crude oil sales price was $45.92 per barrel, a 33 percent decrease from 2012, generally consistent with the decrease in the WCS benchmark price.

In the first quarter, approximately 84 percent (2012 – 54 percent) of our Christina Lake production was sold as Christina Dilbit Blend ("CDB"), which sells at a discount to WCS. CDB price differential to WCS improved approximately $3.00 per barrel compared to 2012, as CDB gained wider market acceptance in the quarter. The remaining Christina Lake production is sold as part of the WCS stream and is subject to a quality equalization charge.



(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

(barrels per day)	Three Months Ended March 31, 2013	Percent Change	2012
Foster Creek	**55,996**	**(2)%**	57,214
Christina Lake	**44,351**	**79%**	24,733
	100,347	**22%**	81,947
Pelican Lake	**23,687**	**14%**	20,730
	124,034	**21%**	102,677

In the first quarter, Foster Creek production decreased two percent as we experienced a higher than usual number of wells off production as a result of downhole mechanical issues resulting in a loss of production of approximately 4,000 barrels per day for the quarter. Efforts are underway to resolve the downhole issues and we expect production to return to near full capacity of 120,000 gross barrels per day in the third quarter of 2013. Foster Creek has three well pads that are in steam rampdown and are being converted to the blowdown phase. At the later stage of production life, we start to reduce the steam injection and shift to co-injection of methane to optimize the use of steam and reduce energy input. The first well pad started rampdown in the fourth quarter of 2011. Steam injection of one of the pads is no longer occurring; this is referred to as the blowdown phase.

The substantial increase in production at Christina Lake resulted from phase C reaching full capacity in the second quarter of 2012 and the start-up of phase D in the third quarter of 2012 which reached a one day high of 100,176 barrels per day in the quarter. First quarter production at Christina Lake was negatively impacted by treating issues, unplanned plant outages related to commissioning construction, electricity supply and pump failures. These factors resulted in a loss of production of approximately 1,000 barrels per day for the quarter.

Pelican Lake production rose steadily with volumes averaging 14 percent higher due to infill wells being brought on-stream in 2012.

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 depending on 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.

During the first quarter, the decrease of $44 million in royalties was primarily related to lower realized prices and increased capital expenditures at Foster Creek resulting in a royalty based on gross revenues. The effective royalty rates for the first quarter were 2.9 percent at Foster Creek (2012 – 13.9 percent), 5.7 percent at Christina Lake (2012 – 7.0 percent) and 6.2 percent at Pelican Lake (2012 – 4.5 percent).

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 $62 million or 14 percent in the first quarter. The condensate (blending) portion of the cost increase was $63 million, the result of higher condensate volumes required for the increased production at Christina Lake, partially offset by decreases in the average cost of condensate. Transportation charges were lower due to volumes shipped on the Trans Mountain pipeline system which we have a long-term commitment for firm service since February 2012.

Operating

Our operating costs for the first quarter were primarily for workforce, fuel, workover activities, and repairs and maintenance. In total, operating costs increased $25 million. At Christina Lake increases were related to higher fuel prices and volume, waste fluid handling and trucking costs, and workforce. At Foster Creek we had higher fuel prices and volume, and workforce, partially offset by lower repairs and maintenance. Increases at Pelican Lake were for higher chemical cost related to the expanded polymer flood.

Per Unit Operating Costts	Three Months Ended March 31,		
($/bbl)	**2013**	**Percent Change**	2012
Foster Creek	**14.03**	**9%**	12.85
Christina Lake	**12.93**	**(16)%**	15.33
Pelican Lake	**19.23**	**20%**	16.05

On a per barrel basis, Foster Creek operating costs increased $1.18 per barrel due to increased fuel prices and volume and workforce, partially offset by a reduction in repairs and maintenance activity. Christina Lake operating costs decreased $2.40 on a per barrel basis due to the increase in production. Operating costs increased $3.18 per barrel at Pelican Lake mainly due to increased polymer volumes and workover activities.

Risk Management

Risk management activities in the first quarter resulted in realized gains of $29 million (2012 – realized losses of $18 million), 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 decreased to 20 MMcf per day in the first quarter (2012 – 41 MMcf per day) as the result of anticipated natural declines. In addition, the internal use of our natural gas production increased at Foster Creek as deliverability issues encountered in the first quarter of 2012 were not present in the first quarter.

Operating Cash Flow was $4 million in the first quarter (2012 – $4 million) due to lower production volumes offset partially by higher sales prices.

Oil Sands – Capital Investment

	Three Months Ended March 31,	
($ millions)	**2013**	2012
Foster Creek	**210**	159
Christina Lake	**175**	138
	385	297
Pelican Lake	**143**	139
Narrows Lake	**25**	9
Telephone Lake	**53**	91
Grand Rapids	**18**	34
Other (1)	**53**	66
Capital Investment (2)	**677**	636

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

Foster Creek

Foster Creek capital investment increased in the first quarter compared to 2012 primarily as a result of higher phase G spending on module assembly and piling work, and phase H site preparation, piling and procurement. Capital spending on phase F, where first production is expected in the third quarter of 2014, has been at consistent levels to 2012. Spending in the quarter includes the drilling of 111 gross stratigraphic test wells (2012 – 124 gross wells) and spending on the construction of a new camp facility.

Christina Lake

Christina Lake capital investment increased in the first quarter compared to 2012 primarily due to phase E plant and well pad construction and phase F procurement, plant construction and major equipment fabrication. Capital investment also included the drilling of stratigraphic test wells (2013 – 68 gross wells; 2012 – 97 gross wells) and higher spending on maintenance capital. The increases in capital investment were partially reduced by the completion of phase D construction in the second quarter of 2012.

Pelican Lake

Pelican Lake capital investment in the first quarter increased compared to 2012 due to infill drilling for expansion of the polymer flood, facilities expansions and infrastructure capital. Facilities spending focused on upgrades to the emulsion pipelines, corrosion mitigation on pad piping and electrical transformer upgrades to increase capacity for future facilities and infill pad power requirements. Capital investment also included the drilling of six stratigraphic test wells in the first quarter of 2013 (2012 – five wells).

Narrows Lake

Capital investment increased at Narrows Lake in the first quarter compared to 2012 as site preparation and procurement for phase A progressed subsequent to final partner approval in December 2012. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 38 gross wells).

Telephone Lake

Capital investment at Telephone Lake decreased in the first quarter compared to 2012 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. The dewatering pilot commenced in the fourth quarter of 2012 and continues in 2013 with the removal and reinjection of water and monitoring of results. Capital investment also included the drilling of 28 stratigraphic test wells in the first quarter (2012 – 29 wells).

Gross Production Wells Drilled (1)

	Three Months Ended March 31,	
	2013	2012
Foster Creek	**1**	10
Christina Lake	**5**	9
	6	19
Pelican Lake	**18**	13
Grand Rapids	**-**	1
	24	33

(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. Capital investment for 2013 is forecasted to be between $790 million and $870 million.

Production from phase E at Christina Lake is anticipated in the third quarter of 2013. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G. Expansion work on these phases is continuing in 2013 as planned. We submitted a joint application and EIA to regulators in March 2013 for phase H expansion. In 2013, capital investment is forecasted to be between $570 million and $630 million.

At Pelican Lake we are continuing with the expansion of the infill drilling program, in addition to piloting new techniques to optimize production. During the first quarter of 2013, the rate at which we are expanding the polymer flood has slowed to better match our production growth.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A. Site preparation and procurement is underway, with construction of the phase A plant scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have 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 $140 million and $160 million in 2013.

Additional capital investment of approximately $270 to $300 million in 2013 is expected to be incurred at our emerging SAGD projects, including Grand Rapids and Telephone Lake. We anticipate regulatory approval for Grand Rapids by the end of 2013. Steam injection started on the second pilot well pair during the third quarter of 2012 and first production was achieved in February 2013. At Telephone Lake, we are advancing the regulatory application for the project and continuing with operation of the dewatering pilot. We anticipate receiving regulatory approval in 2014.

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 have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval.

To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, typically between the end of the fourth quarter and the end of the first quarter. In 2012, we developed the SkyStrat™ drilling rig, which uses a helicopter and an experimental lightweight drilling rig to allow stratigraphic well drilling to occur year-round in remote exploratory drilling locations. We have drilled 18 wells using the SkyStrat™ drilling rig in the last two years.

Gross Stratigraphic Test Wells Drilled

	Three Months Ended March 31, 2013	2012
Foster Creek	**111**	124
Christina Lake	**68**	97
	179	221
Pelican Lake	**6**	5
Narrows Lake	**26**	38
Telephone Lake	**28**	29
Grand Rapids	**1**	41
Other	**72**	85
	312	419

CONVENTIONAL

Our Conventional operations include the development and production of crude oil and NGLs and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In Saskatchewan, our Conventional properties are predominantly crude oil producing properties, most notably the carbon dioxide enhanced oil recovery project in Weyburn. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil products produced. The reliability of these properties to deliver consistent production and Operating Cash Flow is important to funding our future crude oil growth. We plan to continue assessing the potential of new crude oil projects within our existing properties, as well as new regions, especially tight oil opportunities.

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

- Alberta crude oil production averaging 32,047 barrels per day, increasing nine percent primarily due to increased light and medium crude oil production as a result of successful horizontal well performance; and
- Generating Operating Cash Flow in excess of capital investment of $103 million from our Conventional natural gas assets, a decrease of nine percent from 2012. In the low commodity price environment, we have chosen to manage natural gas capital spending for the past several years focusing on high rate of return projects.

In the first quarter of 2013, Management decided to launch a public sales process to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. The associated property, plant and equipment and decommissioning liabilities of $362 million and $33 million, respectively, were reclassified at March 31, 2013 as assets and liabilities held for sale. During the first quarter, Lower Shaunavon and Bakken properties held for sale had crude oil production averaging 5,661 barrels per day (2012 – 5,725 barrels per day).

Conventional – Crude Oil and NGLs

Financial Results

($ millions)	Three Months Ended March 31, 2013	2012
Gross Sales	**389**	454
Less: Royalties	**35**	54
Revenues	**354**	400
Expenses		
Transportation and Blending	**40**	38
Operating	**84**	79
Production and Mineral Taxes	**9**	9
(Gain) Loss on Risk Management	**(14)**	7
Operating Cash Flow	**235**	267
Capital Investment	**190**	216
Operating Cash Flow in Excess of Related Capital Investment	**45**	51

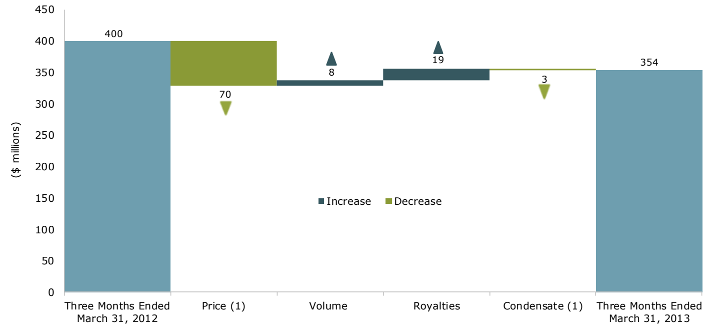
Revenues

Pricing

Our average crude oil sales price in the first quarter decreased 16 percent to $72.11 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil and NGLs production increased four percent in the first quarter, primarily due to an increase in light and medium crude oil production in Alberta, as a result of better horizontal well performance. Crude oil production in Alberta increased nine percent to an average of 32,047 barrels per day while production in Saskatchewan decreased one percent to an average of 23,173 barrels per day.



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

(barrels per day)	Three Months Ended March 31, 2013	Percent Change	2012
Heavy Oil			
Alberta	**16,712**	**1%**	16,624
Light and Medium Oil			
Alberta	**15,335**	**19%**	12,898
Saskatchewan	**23,173**	**(1)%**	23,513
NGLs	**971**	**(15)%**	1,138
	56,191	**4%**	54,173

Royalties

Royalties decreased $19 million largely due to lower royalties in Weyburn as a result of lower realized crude oil prices. The effective crude oil royalty rate in the first quarter for the Conventional segment was 10.1 percent (2012 – 13.4 percent). Most of our crude oil production in the Conventional segment is located on fee land which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs increased $2 million in the first quarter of 2013. Transportation costs increased $5 million due to higher produced volumes, a higher proportion of our volumes being subject to spot pipeline tolls and rising costs associated with accessing new markets, such as transporting our growing light and medium crude oil production by rail. The overall cost of condensate used in blending decreased $3 million as a result of lower condensate prices.

Operating

Operating costs are predominantly composed of workforce, workover activities, electricity, and repairs and maintenance. Operating costs increased $5 million in the first quarter of 2013 primarily due to higher electricity, workforce, and waste fluid handling and trucking costs.

Risk Management

Risk management activities in the first quarter resulted in realized gains of $14 million (2012 – realized losses of $7 million), consistent with our contract prices exceeding the average benchmark prices.

Operating Cash Flow in Excess of Capital Investment

Operating Cash Flow in excess of capital investment decreased by $6 million, or 12 percent, in the first quarter due to lower Operating Cash Flow being partially offset by a reduction in capital investment of $26 million.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended March 31, 2013	2012
Gross Sales	**154**	135
Less: Royalties	**2**	2
Revenues	**152**	133
Expenses		
Transportation and Blending	**7**	6
Operating	**51**	54
Production and Mineral Taxes	**1**	1
(Gain) Loss on Risk Management	**(18)**	(56)
Operating Cash Flow	**111**	128
Capital Investment	**8**	15
Operating Cash Flow in Excess of Related Capital Investment	**103**	113

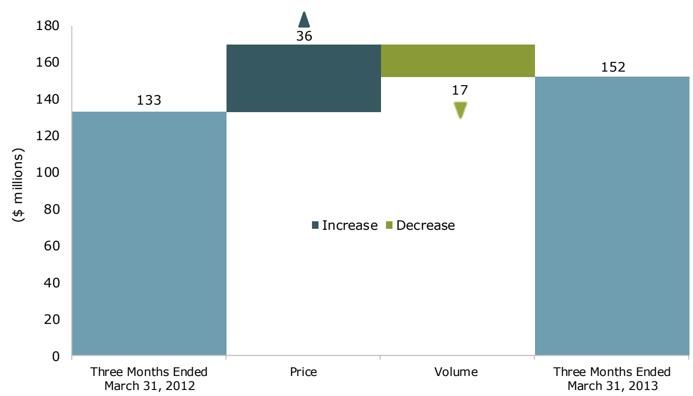
Revenues

Pricing

Our average natural gas sales price in the first quarter increased to $3.25 per Mcf compared to $2.50 per Mcf in 2012, consistent with the increase in the benchmark AECO price.

Production

Production decreased 12 percent to 525 MMcf per day, primarily due to expected natural declines.



Royalties

Royalties remained the same during the first quarter as compared to 2012, as a result of increased prices, despite declines in production. The average royalty rate in the first quarter was 1.7 percent (2012 – 1.7 percent). Most of our natural gas production in the Conventional segment is located on fee land where we hold mineral rights which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs increased $1 million due to increased pipeline rates, offset by decreased production volumes.

Operating

Our operating expenses are composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses decreased $3 million in the first quarter of 2013 due to the reduction in natural gas activity. On a per barrel basis there was a slight increase as a result of higher property taxes and lease costs and electricity.

Risk Management

Risk management activities resulted in realized gains in the first quarter of $18 million (2012 – realized gains of $56 million), consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow in Excess of Capital Investment

Operating Cash Flow from natural gas in excess of capital investment decreased $10 million, or nine percent, due to lower Operating Cash Flow, as a result of lower realized risk management gains and lower production volumes offset by a $7 million reduction in capital investment in the first quarter as compared to 2012.

Conventional – Capital Investment [1]

($ millions)	Three Months Ended March 31, 2013	2012
Crude Oil	**190**	216
Natural Gas	**8**	15
	198	231

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

Capital investment in our Conventional segment focused on crude oil opportunities. Capital was invested in our tight oil drilling programs in southeastern Alberta. In addition, drilling and facilities work continued at Weyburn. Spending on natural gas activities continues to be managed in response to the continuing low price natural gas environment.

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

Conventional Drilling Activity

(net wells, unless otherwise stated)	Three Months Ended March 31, 2013	2012
Crude Oil	**60**	102
Recompletions	**293**	452
Gross Stratigraphic Test Wells	**3**	7

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 first quarter, compared to 2012, include:

- Operating Cash Flow increasing 98 percent to $528 million due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and higher market crack spreads;
- Our refineries processing 416,000 barrels per day of crude oil, including 197,000 barrels per day of heavy crude oil, resulting in 439,000 barrels per day of refined product output; and
- Successfully completed planned maintenance activities.

Refinery Operations [1]

	Three Months Ended March 31, 2013	2012
Crude Oil Capacity [2] (Mbbls/d)	**457**	452
Crude Oil Runs (Mbbls/d)	**416**	445
Heavy Oil	**197**	199
Light/Medium	**219**	246
Crude Utilization (percent)	**91**	98
Refined Products (Mbbls/d)	**439**	465
Gasoline	**225**	230
Distillate	**133**	154
Other	**81**	81

(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 up to 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.

During the first quarter, the amount of crude oil processed decreased seven percent and the amount of heavy oil processed decreased one percent, compared to 2012 as a result of planned maintenance activities.

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 decreased by six percent over 2012 with the proportion of gasoline, distillate and other refined products remaining relatively the same. The decrease was primarily due to planned maintenance activity that occurred in the first quarter of 2013.

Financial Results

($ millions)	Three Months Ended March 31, 2013	2012
Revenues	**2,946**	2,992
Purchased Product	**2,277**	2,589
Gross Margin	**669**	403
Expenses		
Operating	**137**	130
(Gain) Loss on Risk Management	**4**	6
Operating Cash Flow	**528**	267
Capital Investment	**25**	(2)
Operating Cash Flow in Excess of Capital Investment	**503**	269

Gross Margin

The gross margin for the Refining and Marketing segment increased $266 million, or 66 percent in the first quarter, primarily due to lower refinery feedstock costs, partially offset by lower refined product output from planned maintenance activities. Refined product prices were relatively flat in the first quarter as compared to 2012.

Operating

Total operating costs consist mainly of labour, maintenance, utilities and supplies. Operating costs in the first quarter of 2013 increased $7 million due to planned maintenance activities.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment increased $261 million to $528 million in the first quarter of 2013 as a result of lower refinery feedstock costs, partially offset by higher operating costs.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended March 31, 2013	2012
Wood River Refinery	**13**	(8)
Borger Refinery	**12**	6
Marketing	**-**	-
	25	(2)

Capital expenditures in the first quarter of 2013 were focused on capital maintenance and projects improving refinery reliability and safety. Our 2012 capital investment was reduced by Illinois state tax credits of $14 million related to capital expenditures in prior periods at the Wood River Refinery.

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. The unrealized losses on risk management were $230 million for the first quarter (2012 – gains of $64 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

General and Administrative and Financing Costs

($ millions)	Three Months Ended March 31, 2013	2012
General and Administrative	**83**	93
Finance Costs	**123**	113
Interest Income	**(27)**	(29)
Foreign Exchange (Gain) Loss, net	**52**	(16)
Other (Income) Loss, net	**2**	(5)
	233	156

Expenses

General and Administrative

General and administrative expenses decreased $10 million in the first quarter of 2013 primarily due to a decrease of $20 million in long-term incentive costs as a result of a reduction in the price of Cenovus's common shares, partially offset by an increase in salaries and office rent.

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 first quarter, finance costs were $10 million higher than 2012 due to the interest incurred on the US$1.25 billion of senior unsecured notes issued on August 17, 2012, 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 first quarter was 5.3 percent (2012 – 5.4 percent).

Interest Income

Interest income primarily includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. Interest income in the first quarter decreased by $2 million, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

Foreign Exchange

During the first quarter, we recognized net foreign exchange losses of $52 million (2012 – gains of $16 million) which includes unrealized losses of $50 million (2012 – unrealized gains of $31 million) and realized losses of $2 million (2012 – realized losses of $15 million). The majority of unrealized losses are due to translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at March 31, 2013, partially offset by unrealized gains on our U.S. dollar denominated Partnership Contribution Receivable.

DD&A

	Three Months Ended March 31,	
($ millions)	**2013**	2012
Oil Sands	**148**	115
Conventional	**256**	236
Refining and Marketing	**32**	38
Corporate and Eliminations	**19**	11
	455	400

Oil Sands DD&A in the first quarter increased $33 million due to higher sales volumes at Christina Lake and Pelican Lake as well as higher DD&A rates for all of our properties, increasing 15 percent, due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment increased $20 million in the first quarter due to higher crude oil sales volumes and higher DD&A rates, increasing 17 percent from lower proved reserves, partially offset by reduced natural gas sales volumes.

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

Income Tax Expense

	Three Months Ended March 31,	
($ millions)	**2013**	2012
Current Tax		
Canada	**30**	62
United States	**54**	12
Total Current Tax	**84**	74
Deferred Tax	**39**	94
	123	168
Effective Tax Rate	**42%**	28%

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. The increase in our effective tax rate in 2013, when compared to 2012, reflects a loss in Canada, a lower tax rate jurisdiction, and income in the U.S., a higher tax rate jurisdiction. The loss in Canada is due to unrealized risk management losses.

In the first quarter, our current tax expense has increased in comparison to 2012, due to increased income from our U.S. operations and the anticipated utilization of all remaining federal net operating losses. This is partially offset by a decrease in income from Canadian operations. Deferred tax expense for 2013 is lower due to unrealized risk management losses compared to gains in the comparative period, partially offset by increased income in the U.S. operations.

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

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended March 31,	
($ millions)	**2013**	2012
Net Cash From (Used In)		
Operating Activities	**895**	665
Investing Activities	**(903)**	(832)
Net Cash Provided (Used) Before Financing Activities	**(8)**	(167)
Financing Activities	**(166)**	138
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(8)**	(6)
Increase (Decrease) in Cash and Cash Equivalents	**(182)**	(35)

Operating Activities

Cash from operating activities was $230 million higher in the first quarter, mainly due to the $67 million increase in Cash Flow as discussed in the Financial Results section of this MD&A. Cash from operating activities was also impacted by the net change in non-cash working capital.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $938 million at March 31, 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 first quarter was $71 million higher than 2012, primarily due to proceeds on the divestiture of our Boyer property in the first quarter of 2012 for $66 million.

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 first 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 in the first quarter were $184 million (2012 – $166 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

During the first quarter, cash flow used in financing activities increased $304 million. During the first quarter, we did not issue any short-term borrowings as compared to the issuance of $273 million of short-term borrowings in 2012.

Our long-term debt was $4,778 million at March 31, 2013 with no payments of principal due until September 2014 (US$800 million). We had cash and cash equivalents of $978 million at March 31, 2013. The change in long-term debt from December 31, 2012, of $99 million was primarily related to foreign exchange.

Available Sources of Liquidity

($ millions)	Amount	Term
Cash and Cash Equivalents	**978**	**Not Applicable**
Committed Credit Facility	**3,000**	**November 2016**
Canadian Base Shelf Prospectus [1]	**1,500**	**June 2014**
U.S. Base Shelf Prospectus [1]	**US$ 750**	**July 2014**

(1) Availability is subject to market conditions.

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.

As at March 31, 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 Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairment, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**March 31, 2013**	December 31, 2012
Debt to Capitalization	**33%**	32%
Debt to Adjusted EBITDA (times)	**1.1x**	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 of between 1.0 to 2.0 times. At March 31, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

Our debt levels at March 31, 2013 were higher than at March 31, 2012 as a result of the public offering in the U.S. of senior unsecured notes in the third quarter 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 second preferred shares. As at March 31, 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 entitle the holder to receive upon vesting 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 1.82, 6.14 and 2.00 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)	**March 31, 2013**
Common Shares	**755,774**
Stock Options	
NSRs	**25,561**
TSARs	**8,330**
Cenovus Replacement TSARs (held by Encana Employees)	**2,841**
Encana Replacement TSARs (held by Cenovus Employees)	**4,286**
Other Stock-based Compensation Plans	
PSUs	**5,797**
DSUs	**1,161**

Contractual Obligations and Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), 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.

During the first quarter, Cenovus entered into various firm transportation agreements totaling approximately $3.2 billion over the next 20 years helping to align our future transportation requirements with our anticipated production growth.

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. For a further and more in-depth discussion of our risk management see our annual MD&A for the year ended 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 update on our commodity price risk management.

Commodity Price Risk

Fluctuations in future commodity prices create volatility in our financial performance. Commodity prices are impacted 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 activities including 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 March 31, 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 March 31,					
	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**43**	**(190)**	**(147)**	(26)	30	4
Natural Gas	**19**	**(42)**	**(23)**	60	36	96
Refining	**(4)**	**2**	**(2)**	(5)	3	(2)
Power	**-**	**-**	**-**	-	(5)	(5)
Gain (Loss) on Risk Management	**58**	**(230)**	**(172)**	29	64	93
Income Tax Expense	**14**	**(57)**	**(43)**	6	16	22
Gain (Loss) on Risk Management, after-tax	**44**	**(173)**	**(129)**	23	48	71

In the first quarter of 2013, our strategy to manage commodity price risk resulted in realized gains on both crude oil and natural gas financial instruments as contract benchmark commodity prices settled below our contract prices. We recognized unrealized losses on our crude oil and natural gas financial instruments as a result of the increase in forward commodity prices for both crude oil and natural gas and the contraction of forward light/heavy differentials compared to our contract prices. 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 in the first quarter 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 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, International Accounting Standard ("IAS") 19 "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). Cenovus applied the standard retrospectively, as required, 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 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 amendment 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 March 31, 2012	Year Ended December 31, 2012
Increase (Decrease) due to:		
Net Earnings	-	2
Other Comprehensive Income	-	(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

There were no new or amended standards issued during the first quarter of 2013 that are applicable to Cenovus in future periods. A description of 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") during the three months ended March 31, 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.

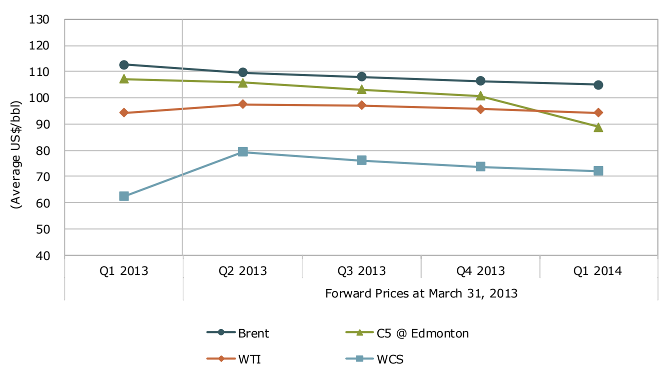
OUTLOOK

We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Grand Rapids and Telephone Lake. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

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 and production interruptions. Short-term prices are likely to remain volatile and be impacted by market expectations;
- Brent-WTI differentials are expected to narrow over the first half of 2013 as new pipeline capacity is added to move crude oil from Cushing to U.S. Gulf Coast markets;
- WCS prices should weaken relative to U.S. Gulf Coast pricing as inland crude oil supply continues to grow at a faster pace than rail and pipeline takeaway capacity, further constraining an already congested transportation system;

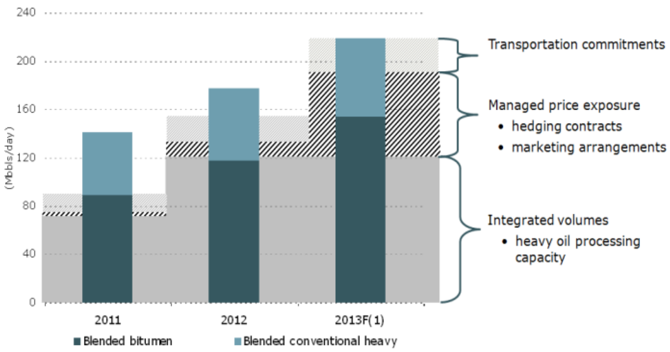


- Refining crack spreads are projected to soften in 2013 when new pipeline capacity out of Cushing should cause WTI crude oil discounts to moderate. Refiners processing WCSB crude oil should continue to see strong margins; and
- Natural gas prices should continue to firm, as supply declines with reduced rig activity and demand growth continues due to still very competitive North American gas pricing.

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 Priorities for 2013

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. This will include increasing our rail shipping capacity for oil to approximately 10,000 barrels per day for 2013, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil. During the first quarter 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 customers base.

Attacking 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 timely regulatory and partner approvals, environmental regulations and 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. We also direct our readers to review the guidance for 2013 that we published on our website, cenovus.com, in connection with our December 2012 news release.

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

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

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at 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.

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; 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 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 and NGLs		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.