Second Quarter
2013

Cenovus oil sands production climbs 17% in second quarter
Company starts producing oil from Christina Lake phase E

- Total oil production was more than 171,000 barrels of oil per day (bbls/d) net in the second quarter, a 10% increase when compared with the same period in 2012.
- Combined oil sands production at Foster Creek and Christina Lake averaged nearly 94,000 bbls/d net in the second quarter, up 17% from a year earlier. Production at Christina Lake climbed 35% to an average of more than 38,000 bbls/d net.
- Christina Lake phase E started steam injection in June, with first production achieved in mid-July.
- Operating cash flow increased 4% to $1.1 billion in the second quarter when compared with the same period a year earlier.
- Cash flow was $871 million in the quarter, a 6% decrease when compared with 2012, mainly due to a conventional oil pre-exploration expense and higher cash tax.
- Discovered bitumen initially-in-place increased 66% since 2009 to 93 billion barrels, reflecting the success of Cenovus's stratigraphic drilling program in converting undiscovered resource inventory to discovered.
- An agreement to sell Cenovus's Shaunavon tight oil asset for $240 million (plus closing adjustments) was announced in early June and closed in early July.

"At Cenovus, we continue to play to our strengths and deliver on our commitments," said Brian Ferguson, Cenovus President & Chief Executive Officer. "We have a track record of predictable and reliable development of our vast oil sands resources. In July, we started producing oil at our tenth expansion phase in the oil sands, Christina Lake phase E, and we expect to bring on a new phase of production in each of the next several years."

Production & financial summary

(for the period ended June 30) Production (before royalties)	**2013 Q2**	2012 Q2	% change
Oil sands total (bbls/d)	**93,797**	80,317	17
Conventional oil[1] (bbls/d)	**77,330**	75,249	3
Total oil (bbls/d)	**171,127**	155,566	10
Natural gas (MMcf/d)	**536**	596	-10
Financial ($ millions, except per share amounts)			
Cash flow[2]	**871**	925	-6
Per share diluted	**1.15**	1.22	
Operating earnings[2]	**255**	284	-10
Per share diluted	**0.34**	0.37	
Net earnings	**179**	397	-55
Per share diluted	**0.24**	0.52	
Capital investment	**706**	660	7

[1] Includes natural gas liquids (NGLs) and Pelican Lake production.

[2] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the earnings reconciliation summary in the operating earnings table.

Calgary, Alberta (July 24, 2013) – Cenovus Energy Inc. (TSX, NYSE: CVE) delivered a solid operational quarter, buoyed by growing oil production from both its oil sands and conventional assets. Combined production from the company's oil sands projects, Christina Lake and Foster Creek, averaged nearly 94,000 bbls/d net in the quarter, a 17% increase from the same period a year earlier. This was primarily driven by the start-up of Christina Lake phase D in the third quarter of 2012 and subsequent ramp-up in the first half of 2013.

Average daily oil production at Christina Lake was more than 38,000 bbls/d net in the quarter, a 35% increase when compared with the same period in 2012. Volumes at Christina Lake were reduced during the quarter by the company's first full planned turnaround at the facility, which was completed successfully and safely. Cenovus started injecting steam for phase E in late June and achieved first production last week. The company expects the ramp-up to take place over the next six to nine months, similar to the ramp-up experienced at Christina Lake phase D.

Foster Creek production averaged more than 55,000 bbls/d net in the quarter, 7% higher than the year before. This increase is due to volumes being reduced in the second quarter of 2012 as the result of a full turnaround at the facility. The 2013 turnaround at Foster Creek is planned to start in late September.

Cenovus's conventional oil assets, including Pelican Lake, continued to deliver steady performance. Production averaged more than 77,000 bbls/d in the quarter, a slight increase from the same period in 2012 partly due to successful well performance related to the company's current drilling program to develop tight oil opportunities in Alberta. Work to expand Cenovus's infill drilling and polymer flood program at Pelican Lake is ongoing, resulting in average production of nearly 24,000 bbls/d in the quarter, 7% higher than the same period a year earlier.

Demonstrating the value of integration

Operating cash flow was $1.1 billion in the quarter, an increase of 4% when compared with the same period a year earlier. Operating cash flow from the company's upstream assets benefited from the West Texas Intermediate (WTI) to Western Canadian Select (WCS) differential narrowing in the second quarter, to an average of US$19.16 per barrel (bbl), a 16% decrease from the same period in 2012. Climbing oil production and increased natural gas prices also contributed to higher operating cash flow. Those benefits were partially offset by higher operating costs, lower realized risk management gains and a decline in operating cash flow generated by the company's refining operations.

Operating cash flow from refining was $316 million in the second quarter, an 8% decrease when compared with the same period a year earlier. The narrowing WTI to WCS differential that benefited the company's upstream operations resulted in increased feedstock costs at Cenovus's refineries. Lower refined product output due to an unplanned hydrocracker outage at Wood River in June also contributed to the decline.

Cash flow in the second quarter was $871 million, a 6% decrease compared with the same period a year earlier. This is due to the same factors that affected operating cash flow, as well as a $63 million conventional oil pre-exploration expense and higher cash tax.

Operating earnings were $255 million in the quarter, a 10% decrease compared with the second quarter of 2012, mainly because of lower cash flow and increased depreciation, depletion and amortization (DD&A), which reflected an impairment of $57 million from the sale of the company's Shaunavon asset. Cenovus also incurred a $46 million exploration expense related to another tight oil play in Saskatchewan.

Cenovus's net earnings for the second quarter were $179 million compared with $397 million in the same period a year earlier, primarily as a result of lower unrealized risk management gains and higher unrealized foreign exchange losses in 2013, partially offset by a decline in deferred tax expense.

Cenovus has updated its 2013 full-year guidance to reflect actual results for the first half of the year and the company's outlook for the remainder of the year. Of note is a slight increase to the operating costs range at Foster Creek, Christina Lake and Pelican Lake based on actual costs for the first six months of the year and expectations for the rest of 2013. Total cash flow remains unchanged. Updated guidance can be found at cenovus.com under "Invest in us."

Accessing new markets remains a priority

Cenovus continues to be rigorous in its efforts to identify new markets for its oil. During the second quarter, the company participated in the open season for TransCanada's Energy East pipeline project and is currently awaiting the results of that process.

"Our manufacturing approach to oil sands expansions has made us a low-cost producer," said Ferguson. "This same approach is also extremely valuable to our transportation strategy. We know we'll have significant new production coming on line every year for the next several years, so we can confidently make long term transportation commitments."

Cenovus plans to transport up to 50% of its oil production through firm commitments over the long term. At this point, the company has made commitments to various pipeline projects to move up to 175,000 bbls/d to the West Coast and up to 150,000 bbls/d to the U.S. Gulf Coast. This transportation plan includes growing rail capacity to move up to 10% of production over the long term. In the second quarter, Cenovus used rail to transport about 7,900 bbls/d to the East Coast and to markets in the U.S. The company expects to move approximately 10,000 bbls/d on rail by the end of 2013 and up to 30,000 bbls/d by the end of 2014.

Business operations maintained during Alberta flooding

The June floods that caused major damage in southern Alberta resulted in restricted access to most of downtown Calgary for nearly a week, including Cenovus's head office and other buildings. The company's business continuity plan to handle this type of situation was successfully activated and all critical systems, communications and business functions continued remotely or from a Cenovus office building outside of downtown Calgary. Cenovus's operations in Alberta were minimally affected by the floods.

"Our thoughts remain with the many people whose lives have been impacted by the flooding," said Ferguson. "We commend the volunteers, including Cenovus staff, who are working to help those in need. Cenovus is donating $1 million to agencies assisting with the relief efforts and those community partners impacted by the floods."

Oil Projects

Daily production[1]								
(Before royalties) (Mbbls/d)	2013		2012					2011
	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands								
Foster Creek	**55**	56	58	59	63	52	57	55
Christina Lake	**38**	44	32	42	32	29	25	12
Oil sands total	**94**	100	90	101	96	80	82	67
Conventional oil								
Pelican Lake	**24**	24	23	24	24	22	21	20
Weyburn	**16**	17	16	16	16	16	17	16
Other conventional[2]	**37**	39	37	37	36	36	38	31
Conventional total	**77**	80	76	77	76	75	75	68
Total oil	**171**	180	165	178	171	156	157	134

[1] Totals may not add due to rounding.
[2] Includes NGLs production.

Oil sands

Cenovus has a substantial portfolio of oil sands assets in northern Alberta with the potential to provide decades of growth. The two currently producing operations, Foster Creek and Christina Lake, use steam-assisted gravity drainage (SAGD), which involves drilling into the reservoir and pumping the oil to the surface. Cenovus has begun work on its third project, Narrows Lake, which is part of the Christina Lake Region. These projects are operated by Cenovus and are jointly owned with ConocoPhillips. Cenovus also has an enormous opportunity to deliver increased shareholder value through production growth from future developments. The company has identified several emerging projects and continues to assess its resources to prioritize development plans and support regulatory applications for new projects.

Foster Creek and Christina Lake

Production

- Combined production at Foster Creek and Christina Lake climbed 17% to 93,797 bbls/d net in the second quarter of 2013 compared with the same period a year earlier.
- Foster Creek produced an average of 55,338 bbls/d net in the quarter, a 7% increase when compared with the same period a year earlier. Volumes were reduced in the second quarter of 2012 due to a full turnaround at the facility. The 2013 turnaround at Foster Creek is scheduled to begin in late September.
- Cenovus continues to reduce the backlog of workover activity required on wells and expects Foster Creek production to return to near full capacity in the fourth quarter.
- Christina Lake production averaged 38,459 bbls/d net, a 35% increase over the same period in 2012 due to the start-up of phase D in the second quarter of 2012. Cenovus completed its first major plant turnaround at the facility, which resulted in 11 days of full production outage and reduced production by about 7,600 bbls/d net in the quarter.

- Steam injection at Christina Lake phase E started in June, with first production achieved in mid-July. Cenovus expects the ramp-up of phase E to take six to nine months, similar to phase D, with the phase ultimately having the capacity to produce 40,000 bbls/d gross.

Wedge Well™ technology

- Cenovus's Wedge Well™ technology uses single horizontal wells, drilled between existing SAGD well pairs, to reach oil that would otherwise be unrecoverable. It has the potential to increase overall recovery from the reservoir between 10% and 15%, while reducing the steam to oil ratio (SOR).
- There are 56 wells at Foster Creek using Wedge Well™ technology and Cenovus anticipates bringing an additional 11 of these wells on production in the second half of 2013.
- Christina Lake is also benefiting from the use of Wedge Well™ technology. There are 10 of these wells now producing and Cenovus expects to drill another 15 wells before the end of the year.

Expansions

- At Christina Lake, procurement, plant construction and major equipment fabrication continue for phase F, which is now about 30% complete. Engineering work continues for phase G.
- At Foster Creek, plant construction for the combined F, G and H expansion is approximately 60% complete. The central plant for phase F is about 78% complete and first production is expected in the third quarter of 2014. Pipe rack and equipment module assembly are essentially complete for phase G, and piling work was completed in May. Overall phase G is about 56% complete, with initial production expected in 2015. At phase H, site preparation, piling work and major equipment procurement continue to progress as planned.
- Combined capital investment at Foster Creek and Christina Lake was $351 million in the second quarter, up from $309 million in the same period of 2012 primarily due to planned spending on expansion phases.

Operating costs

- Operating costs at Foster Creek averaged $16.19/bbl in the second quarter, compared with $12.49/bbl a year earlier, as Cenovus incurred higher workover costs and higher prices for fuel and electricity. Non-fuel operating costs were $13.36/bbl in the quarter compared with $10.89/bbl in the same period of 2012, a 23% increase.
- While operating costs are expected to decrease over the remainder of the year compared with the second quarter, Cenovus has updated its guidance to reflect a higher annual average of between $14.90/bbl and $15.90/bbl for Foster Creek's operating costs.
- Operating costs at Christina Lake were $16.83/bbl in the second quarter, an increase from $12.52/bbl in the same period a year ago due to higher repairs and maintenance associated with the turnaround. Other factors included increased costs for waste fluid handling and trucking, and higher prices for fuel and electricity. Non-fuel operating costs at Christina Lake were $13.46/bbl in the quarter compared with $10.83/bbl in 2012, a 24% increase. While operating costs are expected to decrease over the remainder of the year compared with the second quarter, Cenovus has updated its guidance to reflect a slightly higher annual average of between $12.80/bbl and $13.60/bbl for Christina Lake's operating costs.

Steam to oil ratio (SOR)

- Cenovus uses natural gas to produce steam. The SOR measures the number of barrels of steam needed for every barrel of oil produced. A lower SOR means less steam is required, which reduces the amount of natural gas used. This lowers capital and operating costs, and results in fewer emissions and lower water usage per barrel of oil.
- Cenovus continues to achieve among the lowest SORs in the industry. The combined SOR for Cenovus's oil sands operations was 2.1 in the second quarter of 2013.
- The second quarter SOR at Christina Lake was 1.8, unchanged from the same period a year ago.
- Foster Creek's SOR was 2.4, compared with 2.1 in the second quarter of 2012. The increase is due to a high number of wells undergoing maintenance in the second quarter. Cenovus has updated its 2013 guidance to reflect a revised annual average SOR range for Foster Creek of 2.3 to 2.5.

Christina Dilbit Blend (CDB)

- CDB is a heavy oil blend stream launched in the fourth quarter of 2011. Cenovus sold approximately 92% of its Christina Lake production as CDB in the second quarter of 2013, up from 70% in the same period a year earlier.
- The CDB price differential to WCS improved approximately $0.50/bbl to $5.82/bbl when compared with the same period in 2012 as CDB continues to gain wider market acceptance.
- The Wood River Refinery ran approximately 109,000 bbls/d of CDB or equivalent high-TAN crudes during the second quarter of 2013. These crudes represented approximately 56% of the total heavy crude volumes processed at Wood River in the quarter.

Narrows Lake

- Cenovus's next major oil sands development, a three-phase project at Narrows Lake in northern Alberta, received full regulatory approval and partner approval for the first phase in 2012. The first phase of the project is anticipated to have a production capacity of 45,000 bbls/d gross, with first oil expected in 2017.
- Narrows Lake is expected to be the industry's first project to demonstrate solvent aided process (SAP), using butane, on a commercial scale.
- Site preparation, engineering and procurement are progressing as expected. Construction of the phase A plant is scheduled to start later in the third quarter of 2013.
- Cenovus invested $25 million to advance the Narrows Lake project in the second quarter of this year compared with $9 million in the same period in 2012. This included spending on site preparation, engineering and procurement.

Emerging projects

Telephone Lake

- Cenovus's 100%-owned Telephone Lake property is located within the Borealis Region of northern Alberta. A revised application and environmental impact assessment (EIA) submitted in December 2011 is advancing through the regulatory process with approval anticipated in 2014.
- Cenovus is continuing its dewatering pilot project designed to remove a layer of non-potable water that is sitting on top of the oil sands deposit at Telephone Lake. While dewatering is not essential to the development of Telephone Lake, the company believes it could help improve the project's SOR by up to 30%, which should enhance project economics and reduce its impact on the environment.

- The pilot has been running as expected with positive results. Approximately 50% of the water has been displaced and replaced by air. Cenovus plans to complete the pilot in the fourth quarter of 2013.
- Capital spending in the second quarter was $17 million, up from $13 million a year earlier.

Grand Rapids

- At the company's 100%-owned Grand Rapids project, located within the Greater Pelican Region, work continues on a SAGD pilot project. The pilot project is progressing, with both well pairs operational. Cenovus is planning minor facility upgrades in the third quarter, which is expected to help increase production from the well pairs.
- A regulatory application and EIA for the 180,000 bbl/d commercial project has been submitted and Cenovus anticipates regulatory approval by the end of 2013.
- Capital investment at Grand Rapids was $8 million in the second quarter of 2013, up from $5 million a year earlier.

Conventional oil

Pelican Lake

Cenovus produces heavy oil from the Wabiskaw formation at its 100%-owned Pelican Lake operation in the Greater Pelican Region, about 300 kilometres north of Edmonton. While this property produces conventional heavy oil, it's managed as part of Cenovus's oil sands segment. Since 2006, Cenovus has been injecting polymer to enhance production from the reservoir, which is also under waterflood. Based on reservoir performance of the polymer program, the company has a multi-year growth plan for Pelican Lake with production expected to reach 55,000 bbls/d.

- Pelican Lake produced 23,959 bbls/d in the second quarter of 2013, a 7% increase when compared with the same period in 2012 as infill wells drilled to expand the polymer flood continued to come on production.
- Cenovus invested $111 million at Pelican Lake in the second quarter for infill drilling related to the polymer flood program, facility expansion and other infrastructure, up from $104 million in the same period of 2012.
- The company has decided to delay some capital investment originally planned for 2013 to align spending with the moderate production ramp up currently associated with the polymer flood program.
- Operating costs at Pelican Lake averaged $22.21/bbl in the second quarter, a 25% increase from $17.71/bbl in the same quarter a year earlier mainly due to workover activities, higher electricity prices and usage related to the polymer flood expansion, and repairs and maintenance. While operating costs are expected to decrease over the remainder of the year compared with the second quarter, Cenovus has updated its guidance to reflect a slightly higher annual average of between $19.00/bbl and $20.00/bbl for Pelican Lake's operating costs.

Other conventional oil

In addition to Pelican Lake, Cenovus has conventional oil assets in Alberta, including tight oil opportunities, as well as the established Weyburn operation in Saskatchewan that uses carbon dioxide injection to enhance oil recovery.

- Total conventional oil production averaged 53,371 bbls/d in the second quarter, a slight increase when compared with the same quarter in 2012.

- Conventional oil production in Alberta averaged 32,151 bbls/d in the second quarter, up 7% from the same period in the previous year, primarily due to successful horizontal well performance related to the company's current drilling program to develop tight oil opportunities.
- Production at the Weyburn operation remained steady at 15,938 bbls/d net compared with 16,422 bbls/d net in the second quarter of 2012.
- Cenovus entered into an agreement to sell its Shaunavon tight oil asset in southern Saskatchewan for $240 million (plus closing adjustments) in early June, and closed the transaction in early July. An impairment of $57 million was recorded as depreciation, depletion and amortization (DD&A). The company's Bakken asset remains held for sale.
- Cenovus also incurred a $46 million exploration expense related to another tight oil play in Saskatchewan, as well as a $63 million pre-exploration expense related to a separate conventional oil opportunity.
- Cenovus invested $130 million in its conventional oil assets, the majority of which was dedicated to development of emerging tight oil plays in Alberta.
- Operating costs for Cenovus's conventional oil operations increased 12% to $16.34/bbl in the second quarter of 2013 compared with the same period in 2012. This was mainly due to higher workforce and electricity costs.
- Operating cash flow from conventional oil assets in excess of capital investment increased 14% to $121 million in the second quarter when compared with the same period a year earlier.

Natural Gas

Daily production[1]								
(Before royalties) (MMcf/d)	**2013**		2012					2011
	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural gas	**536**	545	594	566	577	596	636	656

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

- Natural gas production in the second quarter of 2013 was approximately 536 million cubic feet per day (MMcf/d), down 10% from the same period last year, driven by expected natural declines and Cenovus's decision to direct capital investment toward its oil opportunities.
- Cenovus's average realized sales price for natural gas, including hedges, was $3.68 per thousand cubic feet (Mcf) in the period compared with $3.31 per Mcf in the second quarter of 2012.
- The company invested $5 million in its natural gas properties in the second quarter of 2013. Operating cash flow from natural gas in excess of capital investment was $113 million.

Refining

Cenovus's refining operations allow the company to capture value from crude oil production through to refined products such as diesel, gasoline and jet fuel. This integrated strategy provides a natural economic hedge when crude oil prices are discounted by providing lower feedstock costs to the Wood River Refinery in Illinois and Borger Refinery in Texas, which Cenovus jointly owns with the operator, Phillips 66.

- Operating cash flow from refining was $316 million in the quarter, 8% less than the same period a year earlier. This was primarily due to increased feedstock costs consistent with higher oil prices, as well as an unplanned hydrocracker outage at Wood River in June that affected product output.
- Cenovus's refineries processed an average of 439,000 bbls/d of crude oil in the second quarter, resulting in 457,000 bbls/d of refined product output. This was about 3% lower than in the same quarter a year ago primarily due to the unplanned outage at Wood River in June.
- The amount of Canadian heavy oil processed in the second quarter of 2013 was 230,000 bbls/d, similar to the same period a year earlier despite the unplanned outage at Wood River.
- Cenovus's refining operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's second quarter 2013 refining operating cash flow would have been $33 million lower than reported under FIFO, compared with $95 million higher in the same quarter of 2012.
- The company invested $26 million in its refining operations during the second quarter, compared with $24 million in the same quarter of 2012.

Financial

Dividend

The Cenovus Board of Directors declared a third quarter dividend of $0.242 per share, payable on September 30, 2013 to common shareholders of record as of September 13, 2013. Based on the July 23, 2013 closing share price on the Toronto Stock Exchange of $32.25, this represents an annualized yield of about 3%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to the dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

Hedging strategy

Cenovus's natural gas and crude oil hedging strategy helps it to achieve more predictability around cash flow and safeguard its capital program. The Board-approved risk management policy allows the company to financially hedge up to 75% of this year's and next year's expected natural gas production, net of internal fuel usage, and up to 50% and 25%, respectively, in the following two years. The policy also allows the company to enter fixed price hedges on as much as 50% of net liquids production this year and next, as well as 25% of net liquids production for each of the following two years. In addition to financial hedges, Cenovus benefits from a natural hedge with its gas production. About 135 MMcf/d of natural gas is expected to be consumed at the company's SAGD and refinery operations, which is more than offset by the gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's financial hedge positions at June 30, 2013 include:

- approximately 10% or 18,500 bbls/d of expected oil production hedged for 2013 at an average Brent price of US$110.36/bbl and an additional 10% or 18,500 bbls/d at an average Brent price of C$111.72/bbl
- approximately 32% or 166 MMcf/d of expected natural gas production hedged for 2013 at an average NYMEX price of US$4.64/Mcf, plus internal usage of about 135 MMcf/d of natural gas and long-term sales of 29 MMcf/d of natural gas
- approximately 49,000 bbls/d of heavy crude exposure hedged for 2013 at an average WCS differential to WTI of US$20.74/bbl
- approximately 14,900 bbls/d of heavy crude exposure hedged for 2014 at an average WCS differential to WTI of US$20.39/bbl

- approximately 9,000 bbls/d of expected oil production hedged for 2014 at an average Brent price of US$100.35/bbl and an additional 6,000 bbls/d at an average Brent price of C$103.81/bbl

Financial highlights

- Operating cash flow was $1.1 billion in the quarter, an increase of 4% when compared with the same period a year earlier. Operating cash flow from the company's upstream assets benefited from the narrowing WTI to WCS differential, as well as climbing oil production and increased natural gas prices, partially offset by higher operating costs, lower realized risk management gains and a decline in operating cash flow generated by the company's refining operations.
- Cash flow in the second quarter was $871 million, or $1.15 per share diluted, compared with $925 million, or $1.22 per share diluted, in the same period a year earlier as higher oil production and prices were more than offset by higher oil production costs, a decrease in operating cash flow from the company's refining operations, higher cash tax, lower realized risk management gains, and a $63 million conventional oil pre-exploration expense.
- Operating earnings in the quarter were $255 million, or $0.34 per share diluted, down 10% from the same quarter in 2012 mainly because of lower cash flow and increased DD&A, which reflected an impairment of $57 million on the company's Shaunavon asset disposition. Cenovus also incurred a $46 million exploration expense related to another tight oil play in Saskatchewan.
- Cenovus had a realized after-tax hedging gain of $16 million in the second quarter. The company received an average realized price, including hedging, of $70.33/bbl for its oil in the second quarter, compared with $65.56/bbl during the same period in 2012. The average realized price, including hedging, for natural gas in the second quarter was $3.68/Mcf, compared with $3.31/Mcf a year earlier.
- Cenovus recorded income tax expense of $101 million in the second quarter of 2013, giving the company an effective tax rate of 36%, compared with an effective rate of 37% in the year-earlier period.
- Cenovus's net earnings for the second quarter were $179 million compared with $397 million in the same period a year earlier, primarily as a result of lower unrealized risk management gains and higher unrealized foreign exchange losses in 2013, partially offset by a decline in deferred tax expense.
- Capital investment during the quarter was $706 million. That was a 7% increase from $660 million in the second quarter of 2012 as the company continues to expand its oil sands assets.
- General and administrative (G&A) expenses were $82 million in the second quarter, a 46% increase primarily due to an increase in staffing and office rent.
- Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At June 30, 2013, the company's debt to capitalization ratio was 33% and debt to adjusted EBITDA, on a trailing 12-month basis, was 1.2 times.

Operating earnings[1]		
(for the period ended June 30) ($ millions, except per share amounts)	**2013 Q2**	2012 Q2
Net earnings	**179**	397
Add back (deduct):		
Unrealized risk management (gains) losses, after-tax	**(21)**	(126)
Non-operating unrealized foreign exchange (gains) losses, after-tax	**97**	14
Divestiture (gains) losses, after-tax	**-**	(1)
Operating earnings	**255**	284
Per share diluted	**0.34**	0.37

[1] Operating earnings is a non-GAAP measures as defined in the Advisory.

Bitumen initially-in-place

An external evaluation of Cenovus's oil sands assets by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, has identified the discovered portion of best estimate total bitumen initially-in-place (BIIP) on Cenovus lands as at December 31, 2012 has increased 66% to 93 billion barrels since the last evaluation at December 31, 2009.

Cenovus's active stratigraphic well program has been successful in converting much of the previously undiscovered BIIP into discovered BIIP. The company drilled more than 1,200 wells between the beginning of 2010 and the end of 2012. Total BIIP has been stable, increasing 4% from 137 billion barrels to 143 billion barrels over the three-year period, largely as the result of property acquisitions.

Best estimate total bitumen initially-in-place[1] (billion barrels) Company interest at December 31		
	2012	2009
Total bitumen initially-in-place	**143**	137
Discovered bitumen initially-in-place	**93**	56
Commercial discovered bitumen initially-in-place[2]		
Cumulative production[3]	**0.1**	0.1
Reserves (proved + probable)[3]	**2.4**	1.3
Sub-commercial discovered bitumen initially-in-place[4]		
Economic contingent resources[3,5]	**9.6**	5.4
Unrecoverable portion	**81**	49
Undiscovered bitumen initially-in-place	**50**	82
Prospective resources[6]	**8.5**	12.6
Unrecoverable portion	**42**	69

[1] Bitumen initially-in-place estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. See the Advisory for a description of the terms and associated contingencies. Totals may not add due to rounding.

[2] Commercial discovered bitumen initially-in-place equals the cumulative production plus reserves.

[3] Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. Reserves and contingent resources as at December 31, 2009 were evaluated using SEC prices and costs. See the Advisory for details.

[4] Sub-commercial discovered bitumen initially-in-place equals economic contingent resources plus the unrecoverable portion of discovered bitumen initially-in-place.

[5] Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered bitumen initially-in-place. There is no certainty that it will be commercially viable to produce any portion of the resources.

[6] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

A rigorous process determines which portion of the BIIP can be developed and ultimately recovered. Large portions of the total BIIP are classified as unrecoverable because they are contained in accumulations that are too thin, have too low a bitumen concentration, or possess other geological characteristics unsuitable for recovery using current technologies. Deposits that can be developed with current production technologies, such as SAGD, fit into the exploitable bitumen in-place classification provided by the evaluator. Cenovus's total BIIP includes 32 billion barrels of BIIP in the Grosmont carbonate formation. The potential to exploit the Grosmont using technologies currently under development was not considered in the evaluation.

Bitumen recovery estimation (billion barrels) Company interest at December 31		
	2012	2009
Discovered		
Exploitable bitumen in-place[1]	**24**	14
Estimated recovery of exploitable bitumen in-place[2]	**51%**	48%
Undiscovered[3]		
Exploitable bitumen in-place[1]	**16**	25
Estimated recovery of exploitable bitumen in-place[2]	**53%**	51%

[1] See the Advisory for a description of exploitable bitumen in-place.
[2] Estimated recovery is provided by the independent qualified reserves evaluator.
[3] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Oil sands project schedule

Project phase	Regulatory status	First production target	Expected production capacity (bbls/d) gross
Foster Creek[1] A – E			120,000
F	Approved	Q3-2014F	45,000[2]
G	Approved	2015F	40,000
H	Approved	2016F	40,000
J	Submitted Q1-2013	2019F	50,000
Future optimization			15,000
Total capacity			310,000
Christina Lake[1] A – D			98,000
E	Approved	Q3-2013F	40,000
Optimization (phases CDE)	Submitted Q4-2012	2015F	22,000[3]
F	Approved	2016F	50,000
G	Approved	2017F	50,000
H	Submitted Q1-2013	2019F	50,000
Total capacity			310,000
Narrows Lake[1]			
A	Approved	2017F	45,000
B-C	Approved	TBD	85,000
Total capacity			130,000
Telephone Lake[4]	Submitted Q4-2011	TBD	90,000
Grand Rapids	Submitted Q4-2011	TBD	180,000

[1] Properties 50% owned by ConocoPhillips. Certain phases may be subject to partner approval.
[2] Includes 5,000 bbls/d gross submitted to the regulator in Q1 2013.
[3] Increased from 12,000 bbls/d in Q2 2013 due to the addition of blowdown boilers.
[4] Projected total capacity of more than 300,000 bbls/d.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

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

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

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On June 30, 2013, we had a market capitalization of approximately $23 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs production (collectively, "crude oil") in the first six months of 2013 was in excess of 175,600 barrels per day, our average natural gas production was 540 MMcf per day and our refinery operations processed an average of 428,000 gross barrels per day of crude oil feedstock into an average of 448,000 gross barrels per day of refined product.

Our Strategy

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

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

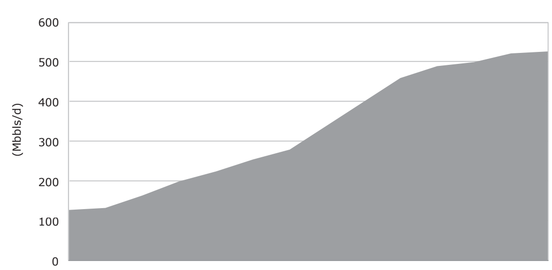
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the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

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

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

Total Crude Oil Production, net to Cenovus



(1) Expected net production capacity.

Oil Sands

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

	Ownership Interest (percent)	Six Months Ended June 30, 2013 Net Production Volumes (bbls/d)	Six Months Ended June 30, 2013 Gross Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects				
Foster Creek	50	55,665	111,330	310,000
Christina Lake	50	41,388	82,776	310,000
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.

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

Christina Lake is producing from phases A through D. Our Phase E expansion commenced steam injection in June 2013 with first production achieved mid-July 2013. Expansion work is currently underway for phases F through G. We submitted an EIA for Christina Lake phase H in the first quarter of 2013 and anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval 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 receiving regulatory approval in the fourth quarter of 2013. At our Telephone Lake project, located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012. The pilot is expected to be completed by the end of 2013. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in 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 an expected ultimate production capacity of 55,000 barrels per day. In the first six months of 2013 our production averaged 23,824 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.

	Six Months Ended June 30, 2013	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow	486	223
Capital Investment	320	12
Operating Cash Flow net of Related Capital Investment	166	211

(1) *Includes NGLs.*

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

Refining and Marketing

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

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

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

($ millions)	Six Months Ended June 30, 2013
Operating Cash Flow	848
Capital Investment	51
Operating Cash Flow net of Related Capital Investment	797

Technology and Environment

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

Dividend

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

Net Asset Value

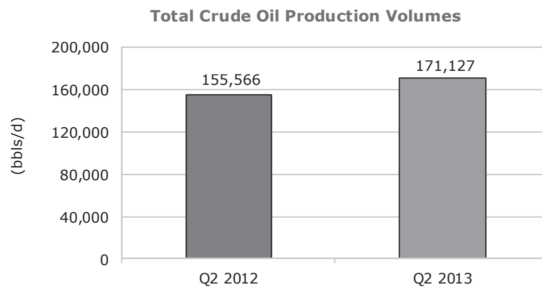
We measure our success in a number of ways with a key measure being growth in net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

The second quarter of 2013 continued to reflect the strength of our integrated approach. Upstream crude oil prices increased nine percent mainly due to the narrowing of the West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differential by 16 percent, averaging US$19.16 per barrel for the quarter (2012 - US$22.87 per barrel). Higher crude oil prices contributed to the 10 percent increase in upstream Operating Cash Flow. While increasing upstream Operating Cash Flow, the narrowing WTI-WCS differential increased the cost of refinery crude oil feedstock as both our refineries process discounted Canadian heavy crude oil which contributed to lower Operating Cash Flow from our refining operations. Refining Operating Cash Flow also decreased due to the processing of lower crude oil volumes as the result of an unplanned hydrocracker outage, partially offset by an improvement in market crack spreads. Overall, the integration of our businesses and growing crude oil production resulted in a four percent increase in total Operating Cash Flow.

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

In the second quarter, crude oil production from our Oil Sands segment averaged 117,756 barrels per day, an increase of 15 percent, as production grew at all three of our producing properties. Average production at Christina Lake for the quarter was 38,459 barrels per day, a 35 percent increase, as phase D, our ninth SAGD expansion phase started to produce in the third quarter of 2012.



Within our Conventional segment, crude oil production averaged 53,371 barrels per day, a slight increase as a result of successful well performance in Alberta offsetting declines in our Saskatchewan production. Alberta crude oil production increased seven percent to an average of 32,151 barrels per day.

Our refining operations processed an average of 439,000 (Q2 2012 – 451,000) gross barrels per day of crude oil, of which 230,000 gross barrels per day was heavy crude oil (Q2 2012 – 229,000). We produced 457,000 gross barrels per day of refined products, a decrease of about 16,000 gross barrels per day, or three percent, due to an unplanned hydrocracker outage.

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

- Completing our first planned turnaround at Christina Lake;
- Christina Lake phase E commencing steam injection in June 2013 with first production achieved mid-July 2013;
- Foster Creek production averaging 55,338 barrels per day, an increase of seven percent, partially due to reduced volumes in the second quarter of 2012 due to a full planned turnaround;
- Pelican Lake production averaging 23,959 barrels per day, an increase of seven percent as a result of improved performance with our infill drilling and polymer flood program;
- Natural gas production declining 10 percent to an average of 536 MMcf per day due to expected natural declines;
- Increasing our access to new sales markets with approximately 7,900 barrels per day transported by rail to the East Coast and the U.S.; and
- Exploration expense related to conventional assets increased from $68 million to $109 million in 2013. In addition, with the agreement to sell the Lower Shaunavon assets for $240 million, an impairment loss of $57 million was recorded to depletion, depreciation, and amortization (“DD&A”).

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

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

Total Operating Cash Flow increased four percent to $1,119 million. Upstream Operating Cash Flow increased as a result of the narrowing of WTI-WCS price differentials, increased natural gas prices and growing crude oil production, partially offset by a rise in operating costs and lower realized risk management gains. Refining and Marketing Operating Cash Flow declined as a result of lower crude oil volumes processed and increased crude oil feedstock costs. Cash Flow declined by six percent to $871 million, as a result of a pre-exploration expense and higher cash tax. Operating Earnings were $255 million, a 10 percent decrease, due to higher DD&A primarily related to our Lower Shaunavon asset, partially offset by lower deferred income tax expense. Net earnings declined 55 percent to $179 million, primarily due to changes in unrealized risk management and unrealized foreign exchange gains and losses.

We paid a second quarter dividend of $0.242 per share (2012 – $0.22 per share), an increase of 10 percent over 2012, demonstrating our continuing commitment to pay a strong and sustainable dividend as part of delivering total shareholder return. Other financial highlights for the second quarter compared to 2012 include:

Revenues

Revenues of $4,516 million, increasing $302 million or seven percent as a result of:

- Our crude oil average sales price (excluding financial hedging) increasing nine percent to $69.61 per barrel;
- Crude oil sales volumes increasing eight percent;
- Our natural gas average sales price (excluding financial hedging) increasing 82 percent to $3.50 per Mcf;
- An increase in Refining and Marketing revenues as a result of higher refined product prices; and
- Higher condensate volumes used for blending, partially offset by decreased condensate prices.

Partially offsetting these increases in revenues were:

- Royalties increasing by 20 percent primarily due to higher crude oil sales volumes and crude oil prices; and
- Lower natural gas sales volumes of 10 percent, as a result of natural declines.

Operating Cash Flow

Operating Cash Flow of $1,119 million, increasing $41 million or four percent due to:

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

Partially offset by:

- An increase in upstream operating expenses of $78 million, partially from higher crude oil production; higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; workover activities related to Foster Creek and Pelican Lake; and electricity, as a result of increases in market prices and consumption;
- Upstream realized risk management gains before tax of $24 million as compared to $96 million in 2012; and
- Operating Cash Flow from our Refining and Marketing segment decreasing $31 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads.

Capital Investment

Capital investment of $706 million, increasing from 2012 by seven percent, primarily due to phased expansions at our oil sands properties.

OPERATING RESULTS

Crude Oil Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
(barrels per day)	2013	Percent Change	2012	2013	Percent Change	2012
Oil Sands						
Foster Creek	**55,338**	**7%**	51,740	**55,665**	**2%**	54,477
Christina Lake	**38,459**	**35%**	28,577	**41,388**	**55%**	26,655
Pelican Lake	**23,959**	**7%**	22,410	**23,824**	**10%**	21,570
Conventional						
Heavy Oil	**16,284**	**4%**	15,703	**16,497**	**2%**	16,163
Light and Medium Oil	**36,137**	**-%**	36,149	**37,317**	**3%**	36,280
NGLs [(1)]	**950**	**(4)%**	987	**961**	**(9)%**	1,061
Total Crude Oil Production	**171,127**	**10%**	155,566	**175,652**	**12%**	156,206

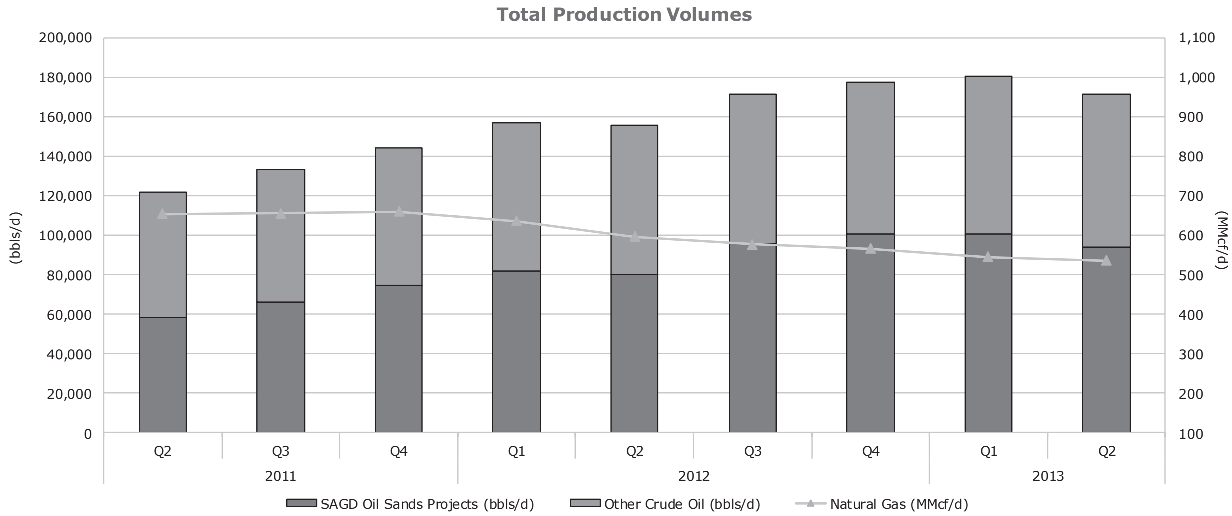
(1) NGLs include condensate volumes.

Our crude oil production rose for the three and six months ended June 30, 2013, primarily at Christina Lake as a result of the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 7,600 barrels per day for the quarter with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Foster Creek production rose as 2012 production was reduced by approximately 7,400 barrels per day for the quarter given the completion of a 14 day planned turnaround. The Foster Creek planned turnaround for 2013 will be completed during the second half of the year. Pelican Lake production increased with improved performance from our infill drilling and polymer flood program. In Alberta, our heavy, light and medium crude oil production was higher as a result of better horizontal well performance from our current drilling program.

Natural Gas Production Volumes

	Three Months Ended June 30,		Six Months Ended June 30,	
(MMcf per day)	2013	2012	2013	2012
Conventional	**512**	563	**518**	579
Oil Sands	**24**	33	**22**	37
	536	596	**540**	616

In the three and six months ended June 30, 2013, our natural gas production declined as expected, in line with our decision to direct capital investment to our crude oil properties. In the low commodity price environment, we continue to manage natural gas capital spending by focusing on high rate of return projects.



Operating Netbacks

	Three Months Ended June 30, 2013		2012		Six Months Ended June 30, 2013		2012	
	Crude Oil [1] ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)	**Crude Oil [1]** ($/bbl)	**Natural Gas** ($/Mcf)	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)
Price [2]	**69.61**	**3.50**	63.92	1.92	**61.55**	**3.38**	69.26	2.22
Royalties	**5.03**	**0.04**	4.67	0.01	**4.19**	**0.05**	6.41	0.03
Transportation and Blending [2]	**2.55**	**0.08**	2.82	0.08	**2.69**	**0.12**	2.81	0.11
Operating Expenses	**17.24**	**1.16**	13.93	0.98	**16.18**	**1.15**	14.33	1.03
Production and Mineral Taxes	**0.61**	**(0.01)**	0.57	0.02	**0.58**	**0.01**	0.58	0.02
Netback Excluding Realized Risk Management	**44.18**	**2.23**	41.93	0.83	**37.91**	**2.05**	45.13	1.03
Realized Risk Management Gain (Loss)	**0.72**	**0.18**	1.64	1.39	**1.71**	**0.28**	(0.07)	1.20
Netback Including Realized Risk Management	**44.90**	**2.41**	43.57	2.22	**39.62**	**2.33**	45.06	2.23

(1) Includes NGLs.
(2) The heavy oil price and transportation and blending costs exclude the cost of purchase condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for the three months ended June 30 was $27.83 per barrel (2012 – $27.93 per barrel) and $29.52 per barrel (2012 – $29.07 per barrel) for the six months ended June 30.

In the three months ended June 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $2.25 per barrel from 2012 primarily due to higher sales prices, partially offset by increased operating costs and royalties. Higher sales prices were consistent with increased benchmark prices, with the average WTI-WCS differential narrowing in the second quarter to US$19.16 per barrel compared to US$22.87 per barrel in 2012.

For the six months ended June 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, decreased $7.22 per barrel from 2012 primarily due to lower sales prices and higher operating costs, partially offset by a decrease in royalties at Foster Creek. Sales price decreases were consistent with lower benchmark prices, with the average WTI-WCS differential widening in the first six months of the year to US$25.56 per barrel compared to US$22.14 per barrel in 2012.

Our average natural gas netback, excluding realized risk management gains and losses, increased $1.40 and $1.02 per Mcf in the second quarter and year-to-date, respectively. This was predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining [1]

	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Crude Oil Runs (Mbbls/d)	**439**	**(3)%**	451	**428**	**(4)%**	448
Heavy Oil	**230**	**-%**	229	**214**	**-%**	214
Crude Utilization (percent)	**96**	**(4)%**	100	**94**	**(5)%**	99
Refined Product (Mbbls/d)	**457**	**(3)%**	473	**448**	**(4)%**	469

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

Crude oil runs, crude utilization and refined product output declined for the three and six months ended June 30, as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in June.

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)

	Six Months Ended June 30,				
	2013	2012	**Q2 2013**	Q1 2013	Q2 2012
Crude Oil Prices (US$/bbl)					
Brent Futures					
Average	**107.88**	113.61	**103.35**	112.64	108.76
End of Period	**102.16**	97.80	**102.16**	110.02	97.80
WTI					
Average	**94.26**	98.15	**94.17**	94.36	93.35
End of Period	**96.56**	84.96	**96.56**	97.23	84.96
Average Differential Brent-WTI	**13.62**	15.46	**9.18**	18.28	15.41
WCS					
Average	**68.70**	76.01	**75.01**	62.40	70.48
End of Period	**82.16**	58.34	**82.16**	82.71	58.34
Average Differential WTI-WCS	**25.56**	22.14	**19.16**	31.96	22.87
Condensate (C5 @ Edmonton) Average	**104.33**	104.70	**101.45**	107.23	99.32
Average Differential WTI-Condensate (Premium)	**(10.07)**	(6.55)	**(7.28)**	(12.87)	(5.97)
Refining Margin 3-2-1 Average Crack Spreads (2) (US$/bbl)					
Chicago	**29.30**	23.60	**31.06**	27.53	28.20
Midwest Combined ("Group 3")	**27.59**	24.89	**27.24**	27.93	28.28
Natural Gas Average Prices					
AECO ($/GJ)	**3.16**	2.06	**3.40**	2.92	1.74
NYMEX (US$/MMBtu)	**3.71**	2.48	**4.09**	3.34	2.22
Basis Differential NYMEX-AECO (US$/MMBtu)	**0.42**	0.30	**0.56**	0.27	0.39
Foreign Exchange Rate (US$ per C$1)					
Average	**0.984**	0.994	**0.977**	0.992	0.990

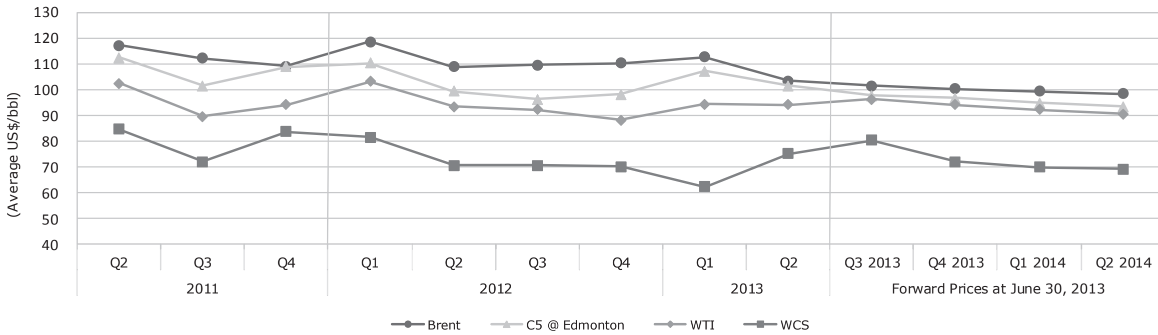
(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.
(2) The 3-2-1 crack spread is an indicator of the refining margin generated 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. The average price of Brent crude oil decreased by US$5.41 per barrel and US$5.73 per barrel for the three and six months ended June 30, 2013, respectively compared to 2012, primarily caused by falling demand due to economic weakness in developed world economies, in addition to North American crude oil supply increases with U.S. and Canadian production rising significantly.

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. Despite declines in the Brent benchmark, WTI increased slightly in the second quarter compared to 2012 as new pipeline capacity from the Cushing area to the U.S. Gulf Coast helped to relieve congestion that created sizable WTI price discounts to Brent. This narrowing of price differentials occurred despite above normal refinery outages in the Chicago and Group 3 markets. In the first six months of the year, WTI prices were roughly $4 per barrel lower than 2012 as a result of the weakening in the Brent crude oil price offset by reduced congestion in the Cushing area.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential narrowed in the second quarter, compared to 2012, due to improved pipeline access from inland markets to the heavy crude oil refining complex in the U.S. Gulf Coast through a pipeline expansion and more effective use of existing pipeline infrastructure. Substantial increases in rail shipments also reduced pipeline congestion for all grades of crude. For the first six months of 2013, the WTI-WCS average differential widened due to severe levels of congestion early in the year prior to the increased pipeline capacity.



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 in both the three and six months ended June 30, 2013 due to strengthening U.S. condensate prices, as access to export markets improved and stronger premiums in the Edmonton market were needed to meet growing condensate requirements.

Refining 3-2-1 Crack Spread Benchmarks

Average crack spreads in the U.S. inland Chicago markets for the second quarter of 2013 rose while the Group 3 crack spread declined slightly. The strength in the Chicago market was due to an unusually large number of planned and unplanned refinery outages. For the first six months of 2013, the improvement in both Chicago and Group 3 crack spreads was due to the weak midcontinent product prices compared to the U.S. Gulf Coast light crude oil prices. This occurred primarily in the first quarter of 2012 as a result of high refinery runs and weak consumer demand.

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 which are based on a first in, first out accounting basis.

Other Benchmarks

Average natural gas prices in the second quarter of 2013 increased significantly as the normal weather of the past winter helped absorb the significant storage surplus that had developed in the extremely warm winter of the previous year. Also helping with the price recovery has been a pattern of slowing supply growth coupled with strong industrial demand growth. For the first six months of 2013, the price increase over the previous year was less dramatic as the full effect of the differences in winter weather was not apparent in the market in the first quarter.

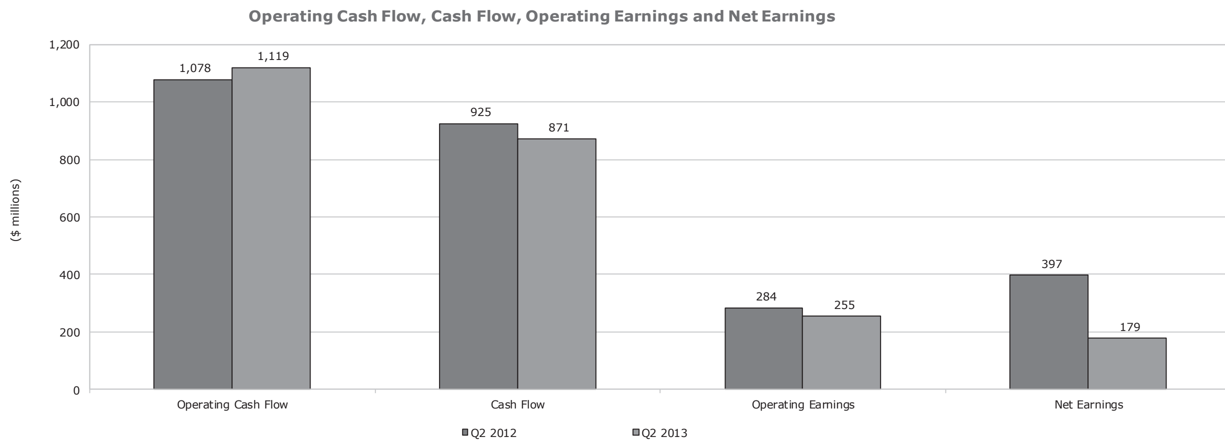
A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also inflates our current period's reported refining capital investment. For the three and six months ended June 30, 2013, the Canadian dollar weakened slightly relative to the U.S. dollar, compared to the same periods last year, but remained close to parity. The principal cause of exchange rate fluctuations has been changes in the U.S. dollar index (i.e. change in the value of the U.S. dollar rather than the

Canadian dollar); although a general weakening of the global commodity prices has contributed to this pattern. The U.S. dollar tends to move in the opposite direction of commodity prices, while the Canadian dollar generally tends to move in the same direction as commodity prices.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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



($ millions, except per share amounts)	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 Q2	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2
Revenues	**8,835**	8,778	**4,516**	4,319	3,724	4,340	4,214	4,564	4,329	3,858	4,009
Operating Cash Flow (1)	**2,330**	2,163	**1,119**	1,211	963	1,310	1,078	1,085	1,019	945	1,064
Cash Flow (1)	**1,842**	1,829	**871**	971	697	1,117	925	904	851	793	939
Per Share – Diluted	**2.43**	2.41	**1.15**	1.28	0.92	1.47	1.22	1.19	1.12	1.05	1.24
Operating Earnings (1) (2)	**646**	624	**255**	391	(188)	432	284	340	332	303	395
Per Share – Diluted (2)	**0.85**	0.82	**0.34**	0.52	(0.25)	0.57	0.37	0.45	0.44	0.40	0.52
Net Earnings (2)	**350**	823	**179**	171	(117)	289	397	426	266	510	655
Per Share – Basic (2)	**0.46**	1.09	**0.24**	0.23	(0.15)	0.38	0.53	0.56	0.35	0.68	0.87
Per Share – Diluted (2)	**0.46**	1.08	**0.24**	0.23	(0.15)	0.38	0.52	0.56	0.35	0.67	0.86
Capital Investment (3)	**1,621**	1,560	**706**	915	978	830	660	900	903	631	476
Cash Dividends	**367**	332	**183**	184	167	166	166	166	151	150	151
Per Share	**0.484**	0.44	**0.242**	0.242	0.22	0.22	0.22	0.22	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)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2012	**4,214**	**8,778**
Increase (Decrease) due to:		
Oil Sands	**139**	**89**
Conventional	**112**	**85**
Refining and Marketing	**116**	**70**
Corporate and Eliminations	**(65)**	**(187)**
Revenues for the Periods Ended June 30, 2013	**4,516**	**8,835**

Upstream revenues rose for the three months ended June 30, 2013 by 19 percent due to higher realized crude oil and natural gas prices, increased crude oil sales and condensate volumes, partially offset by increased royalties, lower natural gas production and reduced condensate prices.

Upstream revenues for the first six months of the year rose six percent due to increased crude oil sales and condensate volumes, higher realized natural gas prices, and reduced royalties, offset by lower realized crude oil prices, decreased condensate prices and a reduction in natural gas production.

Revenues for the three and six months ended June 30, 2013 generated by the Refining and Marketing segment increased four percent and one percent, respectively. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility offset declines in refining revenues as a result of lower refined product output due to planned maintenance in the first quarter and an unplanned hydrocracker outage in June, partially offset by refined product price increases.

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

Operating Cash Flow

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

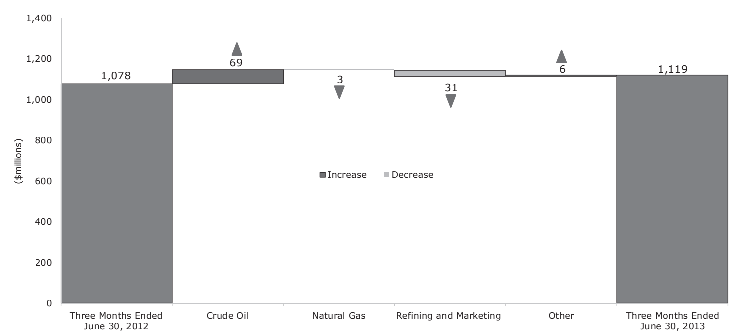
	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Revenues	**4,646**	4,279	**9,087**	8,843
(Add Back) Deduct:				
Purchased Product	**2,616**	2,508	**4,893**	5,097
Transportation and Blending	**460**	431	**1,018**	925
Operating Expenses	**462**	369	**905**	784
Production and Mineral Taxes	**9**	9	**19**	19
Realized (Gain) Loss on Risk Management Activities	**(20)**	(116)	**(78)**	(145)
Operating Cash Flow	**1,119**	1,078	**2,330**	2,163

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

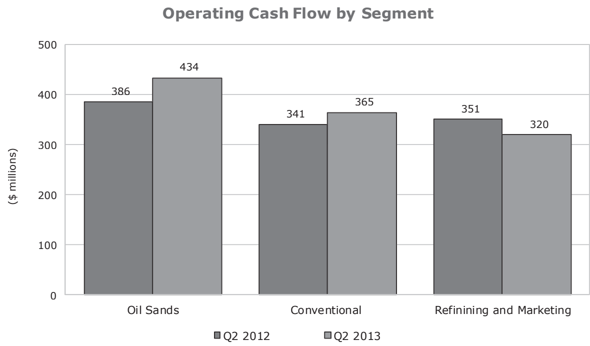
In the second quarter, Operating Cash Flow increased $41 million (four percent).

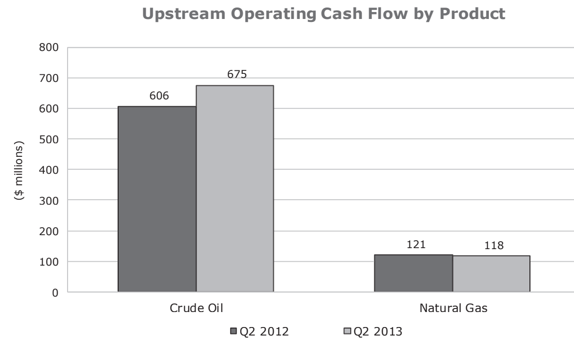
Operating Cash Flow from crude oil increased $69 million (11 percent) due to higher average sales prices and increased production volumes, partially offset by increased operating expenses and royalties.

Operating Cash Flow from natural gas decreased $3 million (two percent), due to lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.

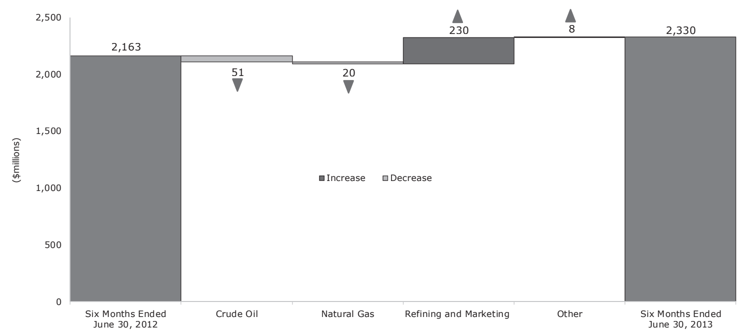


Refining and Marketing Operating Cash Flow declined $31 million (nine percent) due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads.





Operating Cash Flow Variance for the Six Months Ended June 30, 2013 compared to June 30, 2012

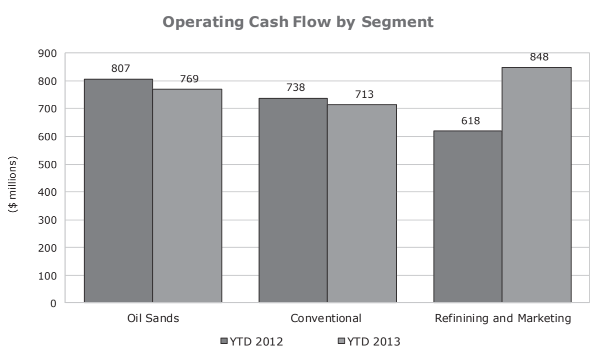


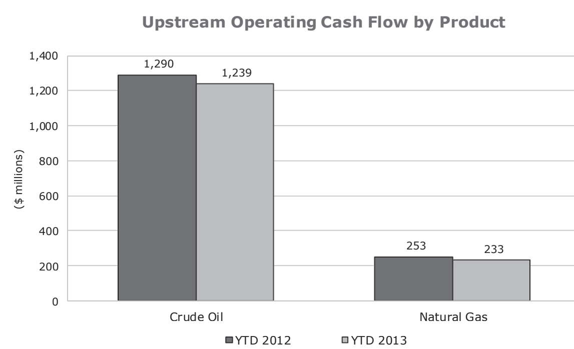
For the first six months of the year, Operating Cash Flow increased $167 million (eight percent).

Operating Cash Flow from crude oil decreased $51 million (four percent) due to lower average sales prices and higher operating expenses partially offset by growing production volumes, lower realized risk management gains and a reduction in royalties.

Operating Cash Flow from natural gas declined $20 million (eight percent) due to lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.

Refining and Marketing Operating Cash Flow was higher by $230 million (37 percent) due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, primarily in the first quarter of 2013, partially offset by lower refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.





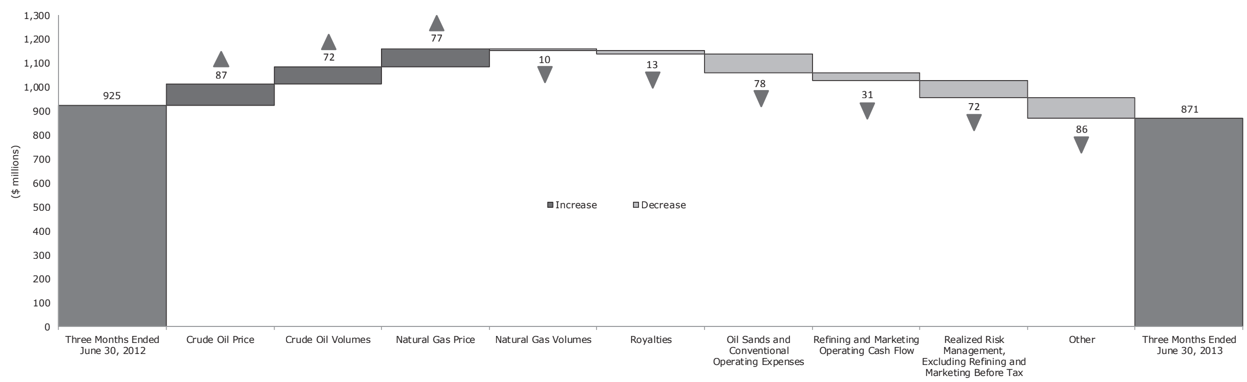
Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Cash From Operating Activities	**828**	968	**1,723**	1,633
(Add Back) Deduct:				
Net Change in Other Assets and Liabilities	**(31)**	(20)	**(65)**	(52)
Net Change in Non-Cash Working Capital	**(12)**	63	**(54)**	(144)
Cash Flow	**871**	925	**1,842**	1,829

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



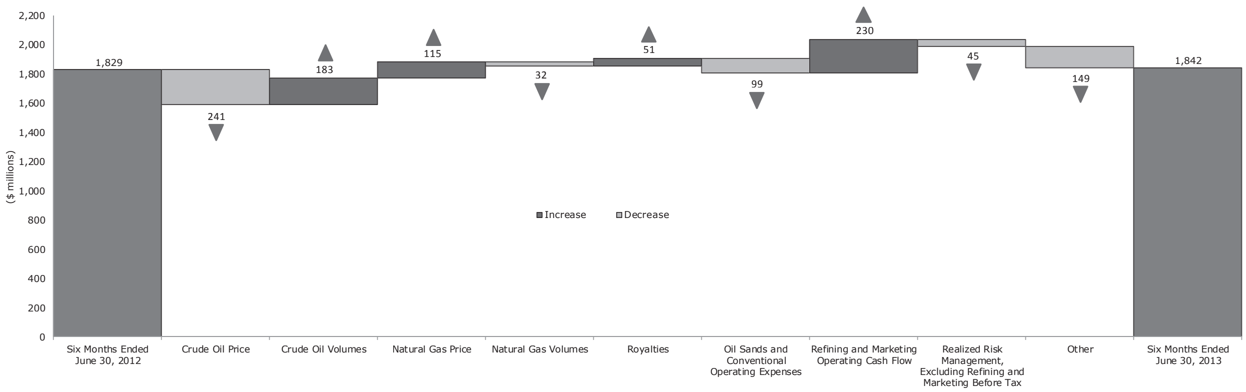
In the second quarter, our Cash Flow decreased $54 million or six percent due to:

- An increase in upstream operating expenses of $78 million, partially from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $3.31 to $17.24 per barrel due to higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; higher workover activities at Foster Creek and Pelican Lake; and rising electricity costs, as a result of increases in market prices and consumption;
- Realized risk management gains before tax, excluding Refining and Marketing, of $24 million compared to gains of $96 million in 2012;
- Pre-exploration expense of $63 million;
- A decline in Operating Cash Flow from Refining and Marketing of $31 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads;
- An increase in current income tax of $27 million as a result of higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses;
- An increase in royalties of $13 million primarily at our oil sands properties as a result of higher sales volumes and crude oil prices; and
- A 10 percent decline in natural gas production as a result of expected natural declines.

The decreases in our Cash Flow were partially offset by:

- A nine percent increase in our average sales price of crude oil to $69.61 per barrel;
- An 82 percent increase in our average sales price of natural gas to $3.50 per Mcf; and
- An increase in our crude oil sales volumes by eight percent.

Cash Flow Variance for the Six Months Ended June 30, 2013 compared to June 30, 2012



For the first six months of the year, our Cash Flow increased $13 million primarily due to:

- An increase in Operating Cash Flow from Refining and Marketing of $230 million due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, primarily in the first quarter of 2013 partially offset by lower refined product output from planned maintenance and an unplanned hydrocracker outage;
- A 10 percent increase in our crude oil sales volumes;
- A 52 percent increase in our average sales price of natural gas to $3.38 per Mcf; and
- A decrease in royalties of $51 million primarily at Foster Creek as a result of lower crude oil prices and increased capital, and in our Conventional segment, also as a result of declines in crude oil prices.

The increases in our Cash Flow were partially offset by:

- An 11 percent decrease in our average sales price of crude oil to $61.55 per barrel;
- An increase in upstream operating expenses of $99 million, mostly from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.85 to $16.18 per barrel primarily due to higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; rising electricity costs, as a result of higher market rates and consumption; rising waste fluid handling and trucking costs, and increased workover activities related to Foster Creek and Pelican Lake;
- Increased general and administrative expenses, excluding non-cash long-term incentive costs, due to higher rent and staffing costs;
- Pre-exploration expense of $63 million;
- Realized risk management gains before tax, excluding Refining and Marketing, of $86 million compared to gains of $131 million in 2012;
- Higher current income tax of $37 million as a result of higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses; and
- A 12 percent decline in natural gas production, primarily as a result of expected natural declines.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Net Earnings	**179**	397	**350**	823
Add Back (Deduct):				
Unrealized Risk Management (Gain) Loss, after-tax (1)	**(21)**	(126)	**152**	(174)
Non-operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2)	**97**	14	**144**	(24)
Gain (Loss) on Divestiture of Assets, after-tax	**-**	(1)	**-**	(1)
Operating Earnings	**255**	284	**646**	624

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

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

Operating Earnings decreased $29 million or 10 percent in the second quarter, primarily as a result of:

- Increased DD&A to reflect an impairment of $57 million on our Lower Shaunavon asset held for sale. In June 2013, we entered into an agreement to sell this asset and the sale was completed in early July 2013;
- Increase in DD&A of $44 million, excluding the Lower Shaunavon impairment, due to higher DD&A rates; and
- Lower Cash Flow as discussed above.

The decrease in Operating Earnings was partially offset by:

- A decline in deferred income tax expense of $126 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, primarily as a result of decreased net income; and
- Exploration expense of $46 million (2012 – $68 million) related to previously capitalized E&E costs.

Year-to-date Operating Earnings increased $22 million or four percent, primarily as a result of:

- A decline in deferred income tax expense of $108 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses;
- A non-cash long-term incentive recovery in 2013 as compared to an expense in 2012; and
- Lower exploration expense related to previously capitalized E&E costs.

The increase in Operating Earnings was partially offset by:

- Increased DD&A of $156 million, including an impairment loss as discussed above; and
- Previously discussed decline in Cash Flow.

Net Earnings Variance

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2012	**397**	**823**
Increase (Decrease) due to:		
Operating Cash Flow	**41**	**167**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss), after-tax	**(105)**	**(326)**
Unrealized Foreign Exchange Gain (Loss)	**(75)**	**(156)**
Expenses [1]	**(36)**	**(32)**
Depreciation, Depletion and Amortization	**(101)**	**(156)**
Exploration Expense	**(41)**	**(41)**
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**99**	**71**
Net Earnings for the Periods Ended June 30, 2013	**179**	**350**

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

For the three and six months ended June 30, 2013, our net earnings decreased 55 percent and 57 percent, respectively, primarily due to:

- Items discussed within Operating Earnings and Cash Flow sections above;
- Unrealized risk management gains, after-tax, of $21 million in the quarter, compared to gains of $126 million in 2012 (year-to-date – unrealized risk management losses, after-tax, of $152 million, compared to gains of $174 million in 2012); and
- Unrealized foreign exchange losses of $84 million in the quarter, compared to losses of $9 million in 2012 (year-to-date – unrealized foreign exchange losses of $134 million, compared to gains of $22 million in 2012).

Net Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Oil Sands	**531**	454	**1,208**	1,090
Conventional	**134**	129	**332**	360
Refining and Marketing	**26**	24	**51**	22
Corporate	**15**	53	**30**	88
Capital Investment	**706**	660	**1,621**	1,560
Acquisitions	**1**	28	**4**	36
Divestitures	**-**	1	**(1)**	(65)
Net Capital Investment [1]	**707**	689	**1,624**	1,531

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

Oil Sands capital investment in 2013 has been focused on the development of the expansion phases at Foster Creek and Christina Lake 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, engineering 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 321 gross stratigraphic test wells. The results of these stratigraphic test wells will be used primarily to support the expansion and development of our Oil Sands projects.

In 2013, Conventional capital investment has been centered on drilling, completion and recompletion programs as well as work on facilities in Saskatchewan and Alberta.

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

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

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

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

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our use of cash flow in the following manner:

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Cash Flow	**843**	925	**1,814**	1,829
Capital Investment (Committed and Growth)	**706**	660	**1,621**	1,560
Free Cash Flow [(1)]	**137**	265	**193**	269
Dividends Paid	**183**	166	**367**	332
	(46)	99	**(174)**	(63)

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

Over the next decade, we expect to increase our net crude oil production to approximately 525,000 barrels per day. In order to meet these project targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 billion for the next decade. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. As at June 30, 2013, we had cash and cash equivalents of $825 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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	2013	2012	2013	2012
Oil Sands	1,030	891	2,016	1,927
Conventional	538	426	1,047	962
Refining and Marketing	3,078	2,962	6,024	5,954
Corporate and Eliminations	(130)	(65)	(252)	(65)
	4,516	4,214	8,835	8,778

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 second quarter compared to 2012 include:

- Christina Lake production increasing 35 percent, to an average of 38,459 barrels per day, with the start-up of phase D in the third quarter of 2012;
- During the quarter we successfully completed our first major planned turnaround at Christina Lake, an 11 day full outage, reducing production by approximately 7,600 barrels per day. Production ramped back up to expected levels by the end of the quarter;
- Christina Lake phase E, our tenth expansion phase, commencing steam injection in June 2013 with first production achieved mid-July 2013; and
- Foster Creek production averaging 55,338 barrels per day, an increase of seven percent, as 2012 production was reduced by approximately 7,400 barrels per day in the quarter given the 14 day planned turnaround.

Oil Sands – Crude Oil

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	2013	2012	2013	2012
Gross Sales	1,049	909	2,044	1,996
Less: Royalties	36	26	57	91
Revenues	1,013	883	1,987	1,905
Expenses				
Transportation and Blending	415	395	926	844
Operating	181	125	344	263
(Gain) Loss on Risk Management	(7)	(15)	(36)	3
Operating Cash Flow	424	378	753	795
Capital Investment	530	454	1,206	1,085
Operating Cash Flow net of Related Capital Investment	(106)	(76)	(453)	(290)

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

Production

	Three Months Ended June 30,			Six Months Ended June 30,		
(barrels per day)	2013	Percent Change	2012	2013	Percent Change	2012
Foster Creek	55,338	7%	51,740	55,665	2%	54,477
Christina Lake	38,459	35%	28,577	41,388	55%	26,655
	93,797	17%	80,317	97,053	20%	81,132
Pelican Lake	23,959	7%	22,410	23,824	10%	21,570
	117,756	15%	102,727	120,877	18%	102,702

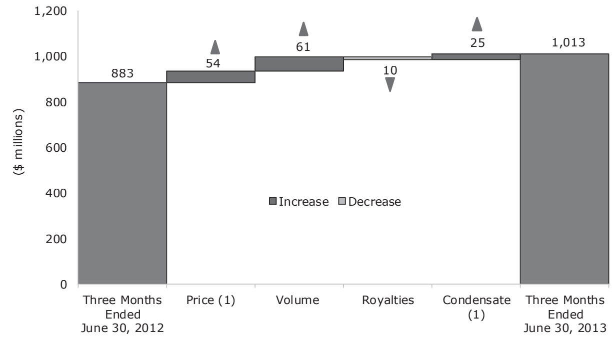
Three Months Ended June 30, 2013 Compared to June 30, 2012

Revenue Variance

Pricing

In the second quarter, our average crude oil sales price was $64.09 per barrel, nine percent higher than 2012, generally consistent with the increase in the WCS benchmark price and strengthening of the Christina Dilbit Blend ("CDB") price.

For the three months ended, approximately 92 percent of our Christina Lake production was sold as CDB (2012 – 70 percent), which sells at a discount to WCS. The CDB price differential to WCS improved approximately $0.50 per barrel compared to 2012, as CDB continues to gain wider market acceptance in 2013. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.



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

Production

In the second quarter, Foster Creek production increased, in comparison to 2012, as 2012 production volumes were reduced by approximately 7,400 barrels per day in the quarter given the completion of a 14 day planned turnaround. The 2013 turnaround is planned for the second half of the year and we expect to return to near full production capacity by the end of the year. We continue to experience a higher than usual number of wells off production as a result of downhole mechanical issues. 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 later in 2013. We continue to have three well pads in steam rampdown that are being converted to the blowdown phase (when steam injection is no longer occurring). 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 output. When well pads convert to blowdown the impact is positive on the overall project as the steam gets redirected to newer wells. The first well pad started rampdown in the fourth quarter of 2011 and steam injection is no longer occurring.

Christina Lake production increased with the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 7,600 barrels per day with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Production ramped back up to expected levels by the end of the quarter.

Pelican Lake production continues to increase due to infill wells being brought on-stream throughout 2012 and 2013.

Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent) to the gross revenues from the project. Gross revenues are a function of volumes and realized prices.

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

Higher sales volumes and crude oil prices at all three of our producing properties contributed to a $10 million increase in royalties in the second quarter.

Effective Royalty Rates

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(percent)	**2013**	2012	**2013**	2012
Foster Creek	**5.7**	4.6	**4.5**	9.7
Christina Lake	**5.6**	7.2	**5.6**	7.1
Pelican Lake	**5.8**	4.2	**6.0**	4.4

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 $20 million or five percent in the second quarter. The blending (condensate) portion of the cost increase was $25 million, mainly due to the higher condensate volumes required for the additional production at Christina Lake, partially offset by decreases in our average cost of condensate. Transportation charges were lower due to increased volumes shipped on the Trans Mountain pipeline system where we have a long-term commitment for firm service, resulting in lower transportation costs for our net share.

Operating

Our operating costs for the second quarter were primarily for workforce, workover activities, fuel and repairs and maintenance. In total, operating costs increased $56 million or $4.06 per barrel.

Per-unit Operating Costs

	Three Months Ended June 30,			Six Months Ended June 30,		
($/bbl)	**2013**	**Percent Change**	2012	**2013**	**Percent Change**	2012
Foster Creek	**16.19**	**30%**	12.49	**15.08**	**19%**	12.68
Christina Lake	**16.83**	**34%**	12.52	**14.66**	**6%**	13.84
Pelican Lake	**22.21**	**25%**	17.71	**20.75**	**23%**	16.81

At Foster Creek operating costs rose $20 million. The increase was associated with:

- Workover activities, as we experienced a higher number of wells off production due to downhole mechanical issues;
- Fuel prices consistent with the rising benchmark AECO natural gas price;
- Fuel volumes due to production growth; and
- Electricity as a result of increased market rates on purchased electricity while our cogeneration units were down for maintenance.

Increases were partially offset by lower repairs and maintenance with the completion of a full planned turnaround during the second quarter of 2012.

Christina Lake operating costs increased $21 million as a result of:

- Higher fuel prices consistent with the benchmark AECO natural gas price;
- Increasing fuel usage as a result of rising production;
- Additional repairs and maintenance costs mainly related to the planned turnaround;
- Higher workforce costs associated with increased production and the planned turnaround; and
- Higher waste fluid handling and trucking costs due to treating and emulsion hauling associated with production growth and the planned turnaround.

Operating costs at Pelican Lake increased $15 million due to higher workover activities, as a result of a higher frequency of downhole equipment failures on some of the injection wells during annual inspection, increased electricity cost (consistent with rising market prices and higher usage related to higher water and polymer injection to support expansion) and increased repairs and maintenance related to planned and unplanned maintenance on the battery and impacts of wet weather.

Risk Management

Risk management activities resulted in realized gains of $7 million (2012 – realized gains of $15 million) in the second quarter of 2013, consistent with our contract prices exceeding average benchmark prices.

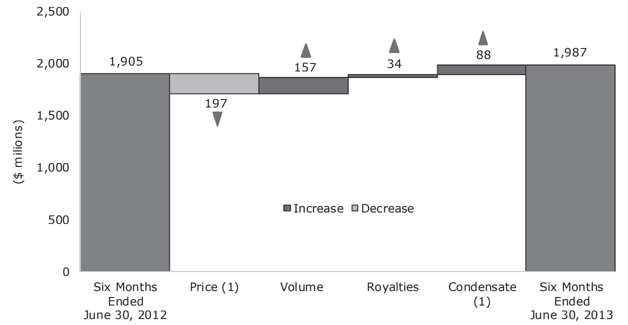
Six Months Ended June 30, 2013 Compared to June 30, 2012

Revenue Variance

Pricing

For the six months ended June 30, 2013, our average crude oil sales price was $54.60 per barrel, a 14 percent decrease from 2012, generally consistent with the decrease in the WCS benchmark price and strengthening of the CDB price.

For the six months ended, approximately 87 percent of our Christina Lake production was sold as CDB (2012 – 60 percent), which sells at a discount to WCS. The CDB price differential to WCS improved approximately $2.00 per barrel compared to 2012, as CDB continues to gain wider market acceptance in 2013. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.



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

Production

In the first six months of the year, production rose slightly at Foster Creek with the completion of the planned turnaround in 2012, partially offset by a higher than usual number of wells off production from downhole mechanical issues as discussed above in the second quarter results. The substantial increase in production at Christina Lake resulted from the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 3,800 barrels per day during the first six months of the year with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Pelican Lake production rose as a result of infill wells being brought on-stream in 2012 and 2013.

Royalties

In the first six months of the year royalties decreased $34 million primarily related to lower realized prices and increased capital expenditures at Foster Creek resulting in a royalty calculation based on gross revenues.

Expenses

Transportation and Blending

Transportation and blending costs rose $82 million or 10 percent year-to-date. The blending (condensate) portion of the cost increase was $88 million, mainly due to the higher condensate volumes required for additional production from Christina Lake, partially offset by a decrease in our average cost of condensate. Transportation charges were lower due to increased volumes shipped on the Trans Mountain pipeline system where we have a long-term commitment for firm service since February 2012, resulting in lower transportation costs for our net share.

Operating

In the first six months of 2013, operating costs were primarily for workforce, workover activities, fuel and repairs and maintenance. In total, operating costs increased $81 million.

At Foster Creek operating costs rose $23 million related to higher fuel prices and volumes, workover activities, workforce and electricity, partially offset by lower repairs and maintenance.

Christina Lake operating costs increased $40 million mainly due to our production growth. Increases were also related to higher fuel prices and volumes, additional waste fluid handling and trucking costs, higher workforce costs and repairs and maintenance associated with the planned turnaround.

Higher operating costs at Pelican Lake were for increased workover activities due to equipment failure, increased chemical consumption related to expansion of the polymer flood, electricity (with increases in market rates and higher consumption) and repairs and maintenance related to planned and unplanned maintenance on the battery and impacts of wet weather.

Risk Management

Risk management activities resulted in realized gains of $36 million (2012 – realized losses of $3 million) in the first six months of 2013, consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production for the three and six months ending June 30, 2013 was 24 MMcf per day and 22 MMcf per day, respectively, decreasing as the result of expected natural declines. In addition, the internal use of our natural gas production at Foster Creek increased in the six months ended June 30, 2013 due to the resolution of deliverability issues encountered in the first quarter of 2012.

Operating Cash Flow was $10 million in the first six months of 2013 (2012 – $13 million) due to higher sales prices offset by lower production volumes.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Foster Creek	**189**	169	**399**	328
Christina Lake	**162**	140	**337**	278
	351	309	**736**	606
Pelican Lake	**111**	104	**254**	243
Narrows Lake	**25**	9	**50**	18
Telephone Lake	**17**	13	**70**	104
Grand Rapids	**8**	5	**26**	39
Other (1)	**19**	14	**72**	80
Capital Investment (2)	**531**	454	**1,208**	1,090

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

Foster Creek

Capital investment for the three and six months ended June 30, 2013 was higher primarily as a result of increased phase G spending on module assembly, piling and procurement, and phase H site preparation, piling and procurement. Capital spending on phase F has been at consistent levels to 2012. Year-to-date spending includes the drilling of 111 gross stratigraphic test wells (2012 – 124 gross wells) and spending on maintenance capital and the construction of a new camp facility.

Christina Lake

Christina Lake capital investment increased for the three and six months ended June 30, 2013 primarily due to phase F procurement, plant construction and major equipment fabrication and phase E plant and well pad construction and drilling of well pairs, with steam injection commencing in June 2013 and first production achieved mid-July 2013. Capital investment also included the drilling of stratigraphic test wells (2013 – 69 gross wells; 2012 – 97 gross wells) in the first six months of the year and higher spending on maintenance and infrastructure capital. Year-to-date increases were partially offset by the completion of phase D construction in the second quarter of 2012.

Pelican Lake

Pelican Lake capital investment was higher in the three and six months ended June 30, 2013 due to detailed engineering and procurement of long lead equipment for a new battery currently planned to be constructed commencing in 2014, partially offset by lower infill drilling and maintenance 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 (2012 – five wells).

Narrows Lake

Capital investment increased at Narrows Lake in the second quarter and in the first six months of the year, as site preparation, engineering 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 rose slightly in the second quarter and decreased year-to-date, with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. The dewatering pilot, which commenced in the fourth quarter of 2012, continued in 2013 with the removal and reinjection of water and monitoring of results. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Gross Production Wells Drilled (1)

	Six Months Ended June 30, 2013	2012
Foster Creek	**25**	11
Christina Lake	**11**	11
	36	22
Pelican Lake	**31**	29
Grand Rapids	**-**	1
Other	**-**	2
	67	54

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

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. Additional production capacity of 45,000 gross barrels per day is expected from phase F in the third quarter of 2014, with production from phases G and H expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Foster Creek capital investment for 2013 is forecasted to be between $790 million and $870 million.

First steam was achieved at Christina Lake phase E in the second quarter of 2013 and first production was achieved mid-July 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, for which we expect to receive regulatory approval in the fourth quarter of 2014. In 2013, Christina Lake capital investment is forecasted to be between $630 million and $670 million.

At Pelican Lake, we are continuing with the expansion of the infill drilling program in addition to piloting new techniques to optimize production. In 2013, the rate at which we are expanding the polymer flood has slowed to better match our production growth. In 2013, Pelican Lake capital investment is forecasted to be between $480 million and $520 million.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A. Site preparation, engineering and procurement are 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 a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $140 million and $160 million in 2013.

Additional capital investment of approximately $270 million to $300 million in 2013 is expected for 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 in the third quarter of 2012 and first production was achieved in February 2013. The Grand Rapids pilot is experiencing facility constraints that have impacted the production of both well pairs. A facility turnaround is expected to mitigate these constraints in the third quarter of 2013. At Telephone Lake, we are advancing the regulatory application for the project and anticipate receiving approval in 2014. In 2013, we are continuing with the operation of the dewatering pilot and plan to complete the pilot in the fourth quarter of 2013, as we have successfully replaced water and confined air, displacing approximately 50 percent of top water in the pilot area to date.

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 in 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 a lightweight drilling rig to allow stratigraphic well drilling to occur year-round in remote drilling locations. We have drilled 26 wells using the SkyStrat™ drilling rig in the last two years.

Gross Stratigraphic Test Wells Drilled

	Six Months Ended June 30, 2013	2012
Foster Creek	111	124
Christina Lake	69	97
	180	221
Pelican Lake	6	5
Narrows Lake	26	38
Telephone Lake	28	29
Grand Rapids	1	41
Other	80	85
	321	419

CONVENTIONAL

Our Conventional operations include the development and production of crude oil and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise 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 produced.

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

- Alberta crude oil production averaging 32,151 barrels per day, increasing seven percent primarily due to additional light and medium crude oil production as a result of successful horizontal well performance associated with our current drilling program;
- Generating Operating Cash Flow, net of capital investment of $231 million, an increase of nine percent from 2012;
- $46 million of previously capitalized E&E costs related to certain tight oil exploration assets were recorded to exploration expense; and
- $63 million of pre-exploration expense.

As part of our strategic plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. As a result of our evaluation of a crude oil exploration opportunity, $63 million of pre-exploration expense was recorded in the quarter.

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

In the second quarter of 2013, $46 million (2012 – $68 million) of previously capitalized E&E costs related to certain conventional tight oil exploration assets were recognized as exploration expense.

Total exploration cost for 2013 was $109 million (2012 – $68 million).

In the first quarter of 2013, Management decided to launch a public sales process to divest our Lower Shaunavon and certain of our 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 Lower Shaunavon property had crude oil production averaging 4,236 barrels per day year-to-date in 2013 (2012 – 4,115 barrels per day) and the Bakken properties for sale had crude oil production averaging 695 barrels per day year-to-date in 2013 (2012 – 1,427 barrels per day).

In June 2013, we entered into a purchase and sale agreement with an unrelated third party, to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of $240 million plus closing adjustments. As at June 30, 2013, an impairment loss of $57 million was recorded as additional DD&A. The sale does not include our Bakken assets, which we continue to market.

Conventional – Crude Oil

Financial Results

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gross Sales	**414**	365	**803**	819
Less: Royalties	**39**	38	**74**	92
Revenues	**375**	327	**729**	727
Expenses				
Transportation and Blending	**41**	31	**81**	69
Operating	**81**	67	**165**	146
Production and Mineral Taxes	**9**	8	**18**	17
(Gain) Loss on Risk Management	**(7)**	(7)	**(21)**	-
Operating Cash Flow	**251**	228	**486**	495
Capital Investment	**130**	122	**320**	338
Operating Cash Flow Net of Related Capital Investment	**121**	106	**166**	157

Production

(barrels per day)	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Heavy Oil						
Alberta	**16,284**	**4%**	15,703	**16,497**	**2%**	16,163
Light and Medium Oil						
Alberta	**14,976**	**11%**	13,532	**15,155**	**15%**	13,215
Saskatchewan	**21,161**	**(6)%**	22,617	**22,162**	**(4)%**	23,065
NGLs	**950**	**(4)%**	987	**961**	**(9)%**	1,061
	53,371	**1%**	52,839	**54,775**	**2%**	53,504

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

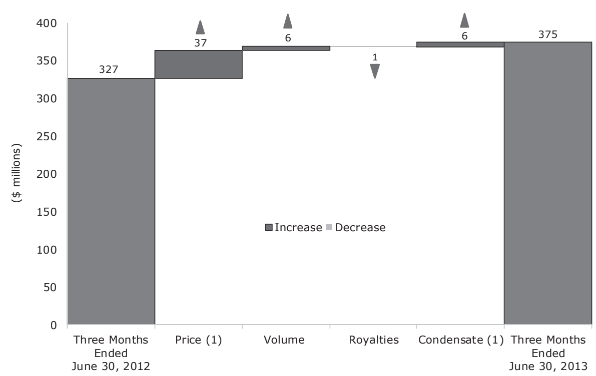
Revenue Variance

Pricing

In the second quarter our average crude oil sales price increased 11 percent to $81.38 per barrel consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil production was higher in the second quarter primarily due to an increase in light and medium crude oil production in Alberta, as a result of successful horizontal well performance related to our current drilling program. In the second quarter, crude oil production in Alberta increased seven percent to an average of 32,151 barrels per day, while production in Saskatchewan decreased six percent to an average of 21,220 barrels per day, as a result of the reduction in capital spending directed towards our Bakken and Lower Shaunavon drilling program.



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

Royalties

Royalties increased by $1 million in the quarter, as a result of higher crude oil prices. The effective crude oil royalty rate in the second quarter for the Conventional segment was 10.7 percent (2012 – 11.7 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 were $10 million higher for the second quarter. Transportation costs rose $4 million due to the higher cost associated with transporting our growing light and medium crude oil production by rail. During the quarter we transported approximately 7,900 barrels per day by rail to the East Coast and the U.S.

(2012 – 2,300 barrels per day). The overall cost of condensate used in blending increased $6 million as a result of higher condensate volumes and prices.

Operating

In the second quarter of 2013 operating costs of $81 million were predominantly composed of workforce, workover activities, and electricity. Compared to the second quarter of 2012, operating costs increased $14 million primarily due to higher workforce costs related to the strategic redeployment of workforce away from natural gas activities to focus on crude oil activities, and higher electricity costs as a result of increased market prices.

Risk Management

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

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment increased by $15 million, or 14 percent, in the second quarter due to higher Operating Cash Flow being partially offset by an $8 million increase in capital investment.

Six Months Ended June 30, 2013 Compared to June 30, 2012

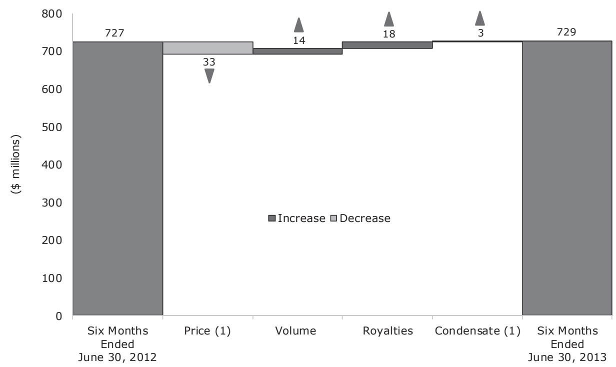
Revenue Variance

Pricing

In the first six months of the year our average crude oil sales price decreased four percent to $76.58 per barrel consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil production increased primarily due to higher light and medium crude oil production in Alberta from better horizontal well performance associated with our current drilling program. Crude oil production in Alberta increased seven percent to an average of 32,554 barrels per day while production in Saskatchewan decreased four percent to an average of 22,221 barrels per day as a result of the reduction in capital spending directed towards our Bakken and Lower Shaunavon drilling program.



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

Royalties

Royalties decreased $18 million largely due to lower royalties in Weyburn as a result of lower realized crude oil prices. The effective crude oil royalty rate during the first six months of the year was 10.4 percent (2012 – 12.7 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $12 million in the first six months of the year. Transportation costs rose $9 million due to the higher cost associated with transporting our growing light and medium crude oil production by rail. During the first half of 2013, we transported approximately 6,800 barrels per day by rail to the East Coast and the U.S. (2012 – 1,400 barrels per day). The overall cost of condensate used in blending increased $3 million as a result of utilizing higher condensate volumes partially offset by lower prices.

Operating

In the first six months of the year, operating costs were predominantly composed of workforce, workover activities, and electricity. Operating costs rose $19 million as compared to 2012, primarily due to higher workforce costs, rising electricity costs, as discussed above, and workovers associated with high return well optimizations that have helped mitigate production declines.

Risk Management

Risk management activities resulted in realized gains of $21 million (2012 – no realized gains or losses), consistent with our contract prices exceeding the average benchmark prices.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment increased by $9 million due to a reduction in capital investment of $18 million, offset by lower Operating Cash Flow.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gross Sales	**163**	99	**317**	234
Less: Royalties	**2**	1	**4**	3
Revenues	**161**	98	**313**	231
Expenses				
Transportation and Blending	**4**	5	**11**	11
Operating	**54**	48	**105**	102
Production and Mineral Taxes	**-**	1	**1**	2
(Gain) Loss on Risk Management	**(9)**	(68)	**(27)**	(124)
Operating Cash Flow	**112**	112	**223**	240
Capital Investment	**4**	7	**12**	22
Operating Cash Flow Net of Related Capital Investment	**108**	105	**211**	218

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

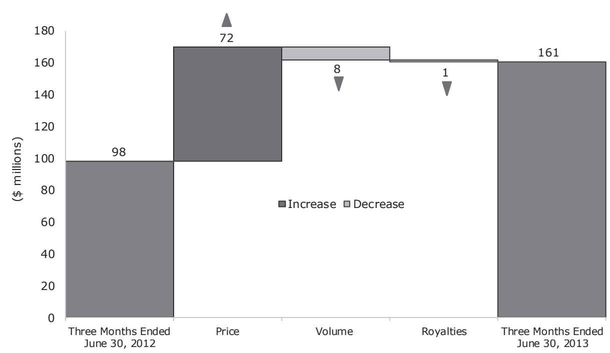
Revenues Variance

Pricing

In the second quarter our average natural gas sales price increased $1.58 per Mcf to $3.50 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased nine percent to 512 MMcf per day in the second quarter primarily due to expected natural declines.



Royalties

Royalties increased in the second quarter as a result of higher prices, despite production declines. The average royalty rate in the second quarter was 1.2 percent (2012 – 1.0 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 being recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs decreased $1 million as a result of lower production volumes.

Operating

In the three months ended June 30, 2013, our operating expenses were composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses increased $6 million due to an increase in the cost of electricity and repairs and maintenance, despite the reduction in natural gas production.

Risk Management

Risk management activities resulted in realized gains in the second quarter of $9 million (2012 – realized gains of $68 million), consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

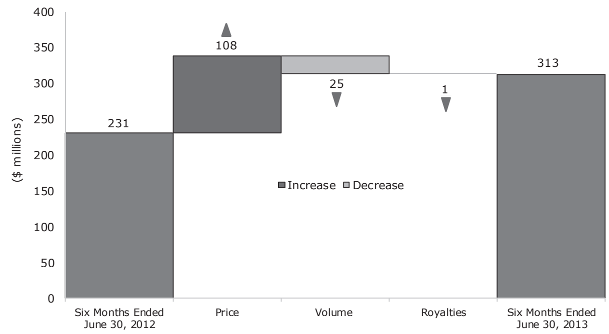
Our Conventional natural gas assets generate significant Operating Cash Flow with minimal capital investment. Operating Cash Flow, net of capital investment increased three percent to $108 million in the second quarter due to higher revenues as a result of a rise in realized sales prices, partially offset by lower realized risk management gains and lower production volumes.

Six Months Ended June 30, 2013 Compared to June 30, 2012

Revenue Variance

Pricing

In the first six months of the year, our average natural gas sales price increased $1.15 per Mcf to $3.37 per Mcf, consistent with the rise in the benchmark AECO natural gas price.



Production

Production decreased 11 percent to 518 MMcf per day in the first six months of the year, primarily due to expected natural declines.

Royalties

Royalties increased in the first six months of the year, as a result of higher prices, despite declines in production. The average royalty rate was 1.4 percent in the first six months of the year (2012 – 1.4 percent).

Expenses

Transportation

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

Operating

For the six months ended June 30, 2013, our operating expenses were composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses increased $3 million due to a rise in the cost of electricity despite the reduction in natural gas production.

Risk Management

Risk management activities resulted in year-to-date realized gains of $27 million (2012 – realized gains of $124 million) consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow from natural gas net of capital investment decreased $7 million to $211 million, due to lower Operating Cash Flow, as a result of lower realized risk management gains and a drop in production volumes, partially offset by a reduction in capital investment.

Conventional – Capital Investment (1)

($ millions)	Three Months Ended June 30, **2013**	2012	Six Months Ended June 30, **2013**	2012
Crude Oil	**130**	122	**320**	338
Natural Gas	**4**	7	**12**	22
	134	129	**332**	360

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

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

Conventional Drilling Activity

(net wells, unless otherwise stated)	Six Months Ended June 30, **2013**	2012
Crude Oil	**64**	114
Recompletions	**317**	579
Gross Stratigraphic Test Wells	**13**	7

Crude oil wells drilled reflect the ongoing 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.

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 second quarter, compared to 2012, include:

- Operating Cash Flow decreasing nine percent to $320 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads; and
- Our refineries processing 439,000 barrels per day of crude oil, including 230,000 barrels per day of heavy crude oil, resulting in 457,000 barrels per day of refined product output, a decrease as a result of an unplanned hydrocracker outage.

Refinery Operations [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	**2013**	2012
Crude Oil Capacity [2] (Mbbls/d)	**457**	452	**457**	452
Crude Oil Runs (Mbbls/d)	**439**	451	**428**	448
Heavy Oil	**230**	229	**214**	214
Light/Medium	**209**	222	**214**	234
Crude Utilization (percent)	**96**	100	**94**	99
Refined Products (Mbbls/d)	**457**	473	**448**	469
Gasoline	**221**	239	**223**	235
Distillate	**145**	154	**139**	154
Other	**91**	80	**86**	80

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

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

In the three and six months ended June 30, 2013, the amount of crude oil processed dropped three and four percent, respectively, as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in June. Heavy crude oil processed remained flat.

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 three and four percent in the second quarter and year-to-date, respectively, with the proportion of gasoline, distillate and other refined products remaining relatively the same. The change was primarily due to planned maintenance and an unplanned hydrocracker outage.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Revenues	**3,078**	2,962	**6,024**	5,954
Purchased Product	**2,616**	2,508	**4,893**	5,097
Gross Margin	**462**	454	**1,131**	857
Expenses				
Operating	**138**	123	**275**	253
(Gain) Loss on Risk Management	**4**	(20)	**8**	(14)
Operating Cash Flow	**320**	351	**848**	618
Capital Investment	**26**	24	**51**	22
Operating Cash Flow, Net of Capital Investment	**294**	327	**797**	596

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

Gross Margin

The gross margin for the Refining and Marketing segment increased $8 million, or two percent in the second quarter, as a result of increased refined product prices, partially offset by lower volumes of crude oil processed as a result of an unplanned hydrocracker outage, and higher crude oil feedstock costs resulting from narrowing Canadian heavy and U.S. inland crude discounts.

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

Our refineries do not blend renewable fuels into their motor fuel products and consequently we are obligated to purchase RINs in the open market. Since the beginning of 2013, the cost of RINs has increased significantly due primarily to current and impending increases to the EPA's mandated blending quotas. Despite the recent increase in RIN prices these costs remain a minor component of our total refinery feedstock costs.

Operating

Total operating costs for the three months ended June 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were higher by $15 million, or 12 percent due to higher utilities as natural gas prices have increased.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment decreased $31 million, or nine percent, as a result of lower volumes of crude oil processed and increased feedstock costs, offset by higher market crack spreads.

Six Months Ended June 30, 2013 Compared to June 30, 2012

Gross Margin

The gross margin for the Refining and Marketing segment increased $274 million, or 32 percent in the first six months, primarily due to lower refinery feedstock costs as inland crude discounts, in particular Canadian heavy crude oil, were wider in early 2013, partially offset by lower crude rates due to planned maintenance and an unplanned hydrocracker outage. Refined product prices were relatively flat in the first six months of the year compared to 2012.

Operating

Total operating costs for the six months ended June 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were higher by $22 million, or nine percent due to planned maintenance activities in the first quarter and higher utilities as natural gas prices have increased.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment increased $230 million, or 37 percent year-to-date due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, partially offset by lower refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Wood River Refinery	13	14	26	6
Borger Refinery	13	10	25	16
	26	24	51	22

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

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

DD&A

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Oil Sands	**150**	110	**298**	225
Conventional	**277**	222	**533**	458
Refining and Marketing	**33**	35	**65**	73
Corporate and Eliminations	**20**	12	**39**	23
	480	379	**935**	779

Oil Sands DD&A in the second quarter increased $40 million (year-to-date – $73 million increase) due to additional sales volumes and higher DD&A rates for all of our properties. DD&A rates averaged 15 percent higher due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment was $55 million higher in the second quarter (year-to-date – increased $75 million) primarily due to a $57 million impairment loss related to our Lower Shanuavon assets which are held for sale. In the six months ended June 30, 2013, the increase in the average DD&A rate was 17 percent from 2012, due to lower proved reserves. The increases were 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. The increase in 2013 is due to the depreciation of our new office space leaseholds which commenced in October 2012.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on the long-term power purchase contract. The unrealized gains on risk management were $26 million for the second quarter (2012 – unrealized gains of $169 million) and year-to-date unrealized losses were $204 million (2012 – unrealized gains of $233 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
General and Administrative	**82**	56	**165**	149
Finance Costs	**124**	111	**247**	224
Interest Income	**(23)**	(27)	**(50)**	(56)
Foreign Exchange (Gain) Loss, net	**96**	25	**148**	9
(Gain) Loss on Divestitures	**-**	(1)	**-**	(1)
Other (Income) Loss, net	**(2)**	1	**-**	(4)
	277	165	**510**	321

Three and Six Months Ended June 30, 2013 Compared to June 30, 2012

General and Administrative

General and administrative expenses increased $26 million in the quarter primarily due to an increase in office rent as well as staffing cost to support our growing operations and a higher long-term incentive recovery in 2012. For the six months ended June 30, 2013, the increase of $16 million was also due to higher rental and staffing costs, offset by lower long-term incentive costs.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In the second quarter, finance costs were $13 million higher (year-to-date – $23 million increase) 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 second quarter was 5.3 percent (2012 – 5.2 percent) and for the six months ended June 30, 2013 was 5.3 percent (2012 – 5.3 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. Interest income for the three and six months ended June 30, 2013 decreased by $4 million and $6 million, respectively, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

Foreign Exchange

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Unrealized Foreign Exchange (Gain) Loss	**84**	9	**134**	(22)
Realized Foreign Exchange (Gain) Loss	**12**	16	**14**	31
	96	25	**148**	9

The majority of unrealized losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at June 30, 2013, partially offset by unrealized gains on our U.S. dollar denominated Partnership Contribution Receivable.

Income Tax Expense

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Current Tax				
Canada	**57**	21	**87**	83
United States	**4**	13	**58**	25
Total Current Tax	**61**	34	**145**	108
Deferred Tax	**40**	204	**79**	298
	101	238	**224**	406
Effective Tax Rate	**36%**	38%	**39%**	33%

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

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. Our effective tax rate for the second quarter is comparable to 2012. Our year-to-date effective tax rate increased compared to 2012 due to a higher proportion of net income attributable to U.S. sources.

In the three and six months ended June 30, 2013, our current tax expense has increased in comparison to 2012 due to higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses.

Deferred income tax expense for the second quarter and year-to-date in 2013, is lower than in 2012 primarily because of lower levels of net income.

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Net Cash From (Used In)				
Operating Activities	**828**	968	**1,723**	1,633
Investing Activities	**(803)**	(788)	**(1,706)**	(1,620)
Net Cash Provided (Used) Before Financing Activities	**25**	180	**17**	13
Financing Activities	**(183)**	(230)	**(349)**	(92)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**5**	(1)	**(3)**	(7)
Increase (Decrease) in Cash and Cash Equivalents	**(153)**	(51)	**(335)**	(86)

Operating Activities

Cash from operating activities was $140 million lower in the second quarter (year-to-date – increase of $90 million). The second quarter decline was mainly due to the $82 million decrease in Cash Flow as discussed in the Financial Results section of this MD&A, and the net change in non-cash working capital. The year-to-date increase was 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 $918 million at June 30, 2013 compared to $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

Cash used in investing activities in the second quarter was $15 million higher (year-to-date – increase of $86 million) than in 2012. These increases were primarily due to an increase in capital expenditures.

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 second quarter, we paid a dividend of $0.242 per share, an increase of 10 percent from 2012 (2012 – $0.22 per share). Total dividend payments year-to-date are $367 million (2012 – $332 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

In the second quarter, cash flow used in financing activities decreased $47 million due to higher repayments on short-term borrowings in the second quarter of 2012, partially offset by an increase in dividends. In the six months ended June 30, 2013, cash flow used in financing activities rose $257 million as a result of less short-term borrowings being issued in 2013 as compared to 2012 and the increase in dividends.

Our long-term debt was $4,948 million at June 30, 2013 with no principal payments due until September 2014 (US$800 million). The $269 million change in long-term debt from December 31, 2012 was related to foreign exchange. We had cash and cash equivalents of $825 million at June 30, 2013.

Available Sources of Liquidity

($ millions)	Amount	Term
Cash and Cash Equivalents	**825**	**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$2,000**	**July 2014**

(1) Availability is subject to market conditions.

A portion of our future cash requirements may be funded through management of our asset portfolio. In the first quarter of 2013, Cenovus decided to launch a public sales process to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. In the second quarter, we entered into an agreement to sell the Shaunavon assets for proceeds of $240 million plus closing adjustments and closed the sale on July 3, 2013. We continue to market our Bakken properties.

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

As at June 30, 2013, we are in compliance with all of the terms of our debt agreements.

Financial Metrics

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

As at	June 30, 2013	December 31, 2012
Debt to Capitalization	**33%**	32%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At June 30, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

At June 30, 2013, our financial position remained relatively consistent with the end of 2012 as measured by our Debt to Capitalization and Debt to Adjusted EBITDA. 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 June 30, 2013, no preferred shares were outstanding.

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

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

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSRs and PSUs are 1.60, 5.91 and 1.75 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)	June 30, 2013
Common Shares	**755,828**
Stock Options	
NSRs	**25,828**
TSARs	**8,106**
Cenovus Replacement TSARs (held by Encana Employees)	**2,672**
Encana Replacement TSARs (held by Cenovus Employees)	**4,166**
Other Stock-based Compensation Plans	
PSUs	**5,813**
DSUs	**1,172**

Contractual Obligations and Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, debt, future building leases, marketing agreements and capital commitments. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, please see the notes to the interim and annual Consolidated Financial Statements.

In the first six months of the year, Cenovus entered into various firm transportation agreements totaling approximately $10 billion. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement and will help align our future transportation requirements within our anticipated production growth.

Legal Proceedings

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

RISK MANAGEMENT

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

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

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended

December 31, 2012. The following provides an overview of our commodity price risk management activities and the effect of our risk management position on earnings for the three and six months ending June 30, 2013.

Commodity Price Risk

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

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

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

Financial Impact of Risk Management Activities

	Three Months Ended June 30,					
	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**11**	**21**	**32**	26	261	287
Natural Gas	**8**	**6**	**14**	75	(97)	(22)
Refining	**(4)**	**(3)**	**(7)**	17	5	22
Power	**5**	**2**	**7**	(2)	-	(2)
Gain (Loss) on Risk Management	**20**	**26**	**46**	116	169	285
Income Tax Expense	**4**	**5**	**9**	32	43	75
Gain (Loss) on Risk Management, after-tax	**16**	**21**	**37**	84	126	210

	Six Months Ended June 30,					
	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**54**	**(169)**	**(115)**	-	291	291
Natural Gas	**27**	**(36)**	**(9)**	135	(61)	74
Refining	**(8)**	**(1)**	**(9)**	12	8	20
Power	**5**	**2**	**7**	(2)	(5)	(7)
Gain (Loss) on Risk Management	**78**	**(204)**	**(126)**	145	233	378
Income Tax Expense (Recovery)	**18**	**(52)**	**(34)**	38	59	97
Gain (Loss) on Risk Management, after-tax	**60**	**(152)**	**(92)**	107	174	281

In the three and six months ended June 30, 2013, management of commodity price risk resulted in realized gains on crude oil, natural gas and power financial instruments as our fixed contract prices settled above the market commodity prices. In the second quarter, we recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices, partially offset by the narrowing of forward light/heavy differentials, compared to prices at the end of the prior quarter, and the realization of settled positions. For the six months ended June 30, 2013 we recognized unrealized losses on our crude oil financial instruments as a result of the realization of settled positions, the narrowing of forward light/heavy differentials, partially offset by the decrease in forward commodity prices for crude oil, compared to prices at the end of the prior year. Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

We are required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Critical Accounting Judgments in Applying Accounting Policies

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

Key Sources of Estimation Uncertainty

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

Changes in Accounting Policies

Joint Arrangements, Consolidation, Associates and Disclosures

As disclosed in the Consolidated Financial Statements, effective January 1, 2013, Cenovus adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to 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 June 30, 2012	Six Months Ended June 30, 2012	Year Ended December 31, 2012
Increase (Decrease) due to:			
Net Earnings	1	1	2
Other Comprehensive Income	(2)	(2)	(4)

Consolidated Balance Sheets

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

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

Fair Value Measurement

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

Presentation of Items in Other Comprehensive Income

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

Offsetting Financial Assets and Financial Liabilities

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

Future Accounting Pronouncements

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

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

CONTROL ENVIRONMENT

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

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

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. This policy and our CR report are available on our website at cenovus.com.

In June 2013, we were recognized for the third time by Corporate Knights Magazine as one of Canada's Best 50 Corporate Citizens. Cenovus was also recognized as one of Canada's Top 50 Socially Responsible Corporations for a second year in a row by Maclean's/Sustainalytics. The recognition of our commitment to corporate responsibility reaffirms Cenovus's efforts to balance economic, governance, social and environmental performance. Cenovus is also a member of the Dow Jones Sustainability World and North America Indices.

OUTLOOK

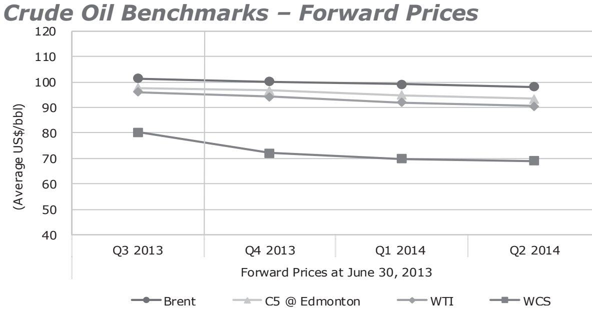
We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and total net oil production of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at 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:

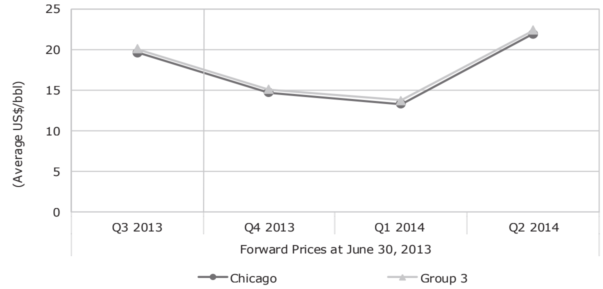
- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. The consensus is for improvement in global economic growth in the second half of 2013 and in 2014. Short-term prices are likely to remain volatile and be influenced by changing market expectations;
- Brent-WTI differentials are expected to continue to narrow over the second half of 2013 as new pipeline capacity is added to move crude oil from Cushing to the U.S. Gulf Coast markets. While the differential is expected to narrow, WTI prices should remain at a discount to Brent prices;
- We expect WCS prices to weaken relative to U.S. Gulf Coast and WTI pricing. With several new oil sands projects starting up over the next several months, inland heavy crude oil supply should increase and push the pipeline system back into a constrained situation.

Crude Oil Benchmarks – Forward Prices



- Refining crack spreads have already materially softened from elevated levels earlier in the quarter as Chicago-area refinery maintenance comes to an end. Refining crack spreads will continue to remain towards the lower end of the range experienced over the past couple of years as inland crude discounts narrow. Refiners processing Western Canadian Sedimentary Basin crude oil should continue to see strong margins. Compared to those processing WTI crudes who will likely see softening margins as the Brent-WTI differential narrows; and
- Natural gas prices are expected to remain near the US$4/MMBtu through the summer but will be affected by summer temperatures and the pace of supply additions. Recent infrastructure additions, which enable new supply to reach market, are not expected to increase prices in the coming quarter. This should allow for further strengthening of prices by year end.

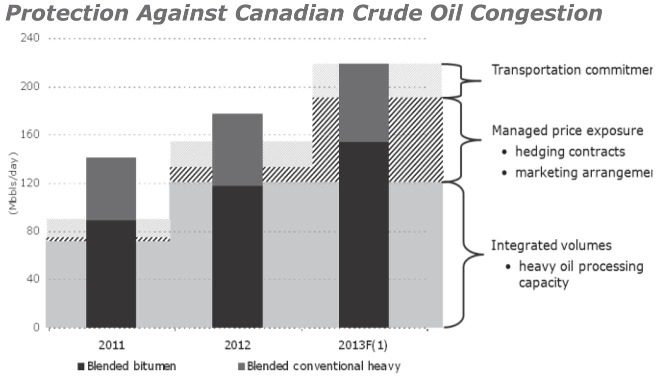
Refining 3-2-1 Crack Spread Benchmarks – Forward Prices



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

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

Protection Against Canadian Crude Oil Congestion



(1) Expected net production capacity.

Update on Key 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. We anticipate increasing our rail shipping capacity for oil to approximately 10,000 barrels per day by the end of 2013, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil. In the second quarter of 2013, we transported approximately 7,900 barrels per day by rail, allowing us to realize higher prices on our crude oil and diversify our customer base. We also entered into $7 billion of new pipeline commitments (some of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth.

Long-term Cost Structures

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

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within the industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section in our annual MD&A. We also direct our readers to review the guidance for 2013 that we published on our website, cenovus.com, in connection with our December 12, 2012 news release and updates to that guidance in the July 24, 2013 news release.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the Period Ended June 30,
($ millions, except per share amounts)

	Notes	Three Months Ended 2013	Three Months Ended 2012	Six Months Ended 2013	Six Months Ended 2012
			(Note 3)		(Note 3)
Revenues	1				
Gross Sales		**4,594**	4,279	**8,971**	8,965
Less: Royalties		**78**	65	**136**	187
		4,516	4,214	**8,835**	8,778
Expenses	1				
Purchased Product		**2,486**	2,443	**4,641**	5,032
Transportation and Blending		**460**	431	**1,018**	925
Operating		**461**	369	**903**	783
Production and Mineral Taxes		**9**	9	**19**	19
(Gain) Loss on Risk Management	19	**(46)**	(285)	**126**	(378)
Depreciation, Depletion and Amortization	12	**480**	379	**935**	779
Exploration Expense		**109**	68	**109**	68
General and Administrative		**82**	56	**165**	149
Finance Costs	4	**124**	111	**247**	224
Interest Income	5	**(23)**	(27)	**(50)**	(56)
Foreign Exchange (Gain) Loss, net	6	**96**	25	**148**	9
(Gain) Loss on Divestiture of Assets		**-**	(1)	**-**	(1)
Other (Income) Loss, net		**(2)**	1	**-**	(4)
Earnings Before Income Tax		**280**	635	**574**	1,229
Income Tax Expense	7	**101**	238	**224**	406
Net Earnings		**179**	397	**350**	823
Other Comprehensive Income (Loss), Net of Tax					
Items That Will Not be Reclassified to Profit or Loss:					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**7**	(2)	**9**	(2)
Items That May be Subsequently Reclassified to Profit or Loss:					
Change in Value of Available for Sale Financial Assets		**8**	-	**8**	-
Foreign Currency Translation Adjustment		**45**	30	**72**	9
Total Other Comprehensive Income (Loss), Net of Tax		**60**	28	**89**	7
Comprehensive Income		**239**	425	**439**	830
Net Earnings Per Common Share	8				
Basic		**$0.24**	$0.53	**$0.46**	$ 1.09
Diluted		**$0.24**	$0.52	**$0.46**	$ 1.08

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
($ millions)

	Notes	June 30, 2013	December 31, 2012 (Note 3)	January 1, 2012 (Note 3)
Assets				
Current Assets				
Cash and Cash Equivalents		**825**	1,160	495
Accounts Receivable and Accrued Revenues		**1,720**	1,464	1,405
Current Portion of Partnership Contribution Receivable		**417**	384	372
Inventories	9	**1,378**	1,288	1,291
Risk Management	19	**85**	283	232
Assets Held for Sale	10	**303**	-	116
Current Assets		**4,728**	4,579	3,911
Exploration and Evaluation Assets	1,11	**1,380**	1,285	880
Property, Plant and Equipment, net	1,12	**16,306**	16,152	14,324
Partnership Contribution Receivable		**1,266**	1,398	1,822
Risk Management	19	**8**	5	52
Income Tax Receivable		**-**	-	29
Other Assets		**63**	58	44
Goodwill	1	**739**	739	1,132
Total Assets		**24,490**	24,216	22,194
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts Payable and Accrued Liabilities		**2,733**	2,650	2,579
Income Tax Payable		**269**	217	329
Current Portion of Partnership Contribution Payable		**420**	386	372
Risk Management	19	**11**	17	54
Liabilities Related to Assets Held for Sale	10	**30**	-	54
Current Liabilities		**3,463**	3,270	3,388
Long-Term Debt	13	**4,948**	4,679	3,527
Partnership Contribution Payable		**1,294**	1,426	1,853
Risk Management	19	**2**	1	14
Decommissioning Liabilities	14	**2,027**	2,315	1,777
Other Liabilities		**164**	183	158
Deferred Income Taxes		**2,686**	2,560	2,093
Total Liabilities		**14,584**	14,434	12,810
Shareholders' Equity		**9,906**	9,782	9,384
Total Liabilities and Shareholders' Equity		**24,490**	24,216	22,194

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	Total
	(Note 15)			(Note 16)	
Balance as at December 31, 2011, as Previously Reported	3,780	4,107	1,400	119	9,406
Cumulative Effect of Change in Accounting Policy (Note 3)	-	-	-	(22)	(22)
Balance as at January 1, 2012, Restated	3,780	4,107	1,400	97	9,384
Net Earnings	-	-	823	-	823
Other Comprehensive Income (Loss)	-	-	-	7	7
Total Comprehensive Income for the Period	-	-	823	7	830
Common Shares Issued Under Option Plans	44	-	-	-	44
Stock-Based Compensation Expense	-	22	-	-	22
Dividends on Common Shares	-	-	(332)	-	(332)
Balance as at June 30, 2012, Restated	3,824	4,129	1,891	104	9,948
Balance as at December 31, 2012, as Previously Reported	3,829	4,154	1,728	95	9,806
Cumulative Effect of Change in Accounting Policy (Note 3)	-	-	2	(26)	(24)
Balance as at December 31, 2012, Restated	3,829	4,154	1,730	69	9,782
Net Earnings	-	-	350	-	350
Other Comprehensive Income (Loss)	-	-	-	89	89
Total Comprehensive Income for the Period	-	-	350	89	439
Common Shares Issued Under Option Plans	21	-	-	-	21
Common Shares Cancelled (Note 15)	(3)	3	-	-	-
Stock-Based Compensation Expense	-	31	-	-	31
Dividends on Common Shares	-	-	(367)	-	(367)
Balance as at June 30, 2013	**3,847**	**4,188**	**1,713**	**158**	**9,906**

(1) *Accumulated Other Comprehensive Income (Loss).*

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the Period Ended June 30,
($ millions)

	Notes	Three Months Ended 2013	Three Months Ended 2012 (Note 3)	Six Months Ended 2013	Six Months Ended 2012 (Note 3)
Operating Activities					
Net Earnings		**179**	397	**350**	823
Depreciation, Depletion and Amortization		**480**	379	**935**	779
Exploration Expense		**46**	68	**46**	68
Deferred Income Taxes	7	**40**	204	**79**	298
Unrealized (Gain) Loss on Risk Management	19	**(26)**	(169)	**204**	(233)
Unrealized Foreign Exchange (Gain) Loss	6	**84**	9	**134**	(22)
(Gain) Loss on Divestiture of Assets		**-**	(1)	**-**	(1)
Unwinding of Discount on Decommissioning Liabilities	4,14	**24**	21	**48**	42
Other		**44**	17	**46**	75
		871	925	**1,842**	1,829
Net Change in Other Assets and Liabilities		**(31)**	(20)	**(65)**	(52)
Net Change in Non-Cash Working Capital		**(12)**	63	**(54)**	(144)
Cash From Operating Activities		**828**	968	**1,723**	1,633
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	11	**(53)**	(76)	**(221)**	(347)
Capital Expenditures – Property, Plant and Equipment	12	**(654)**	(612)	**(1,404)**	(1,249)
Proceeds From Divestiture of Assets		**-**	(1)	**1**	65
Net Change in Investments and Other		**(4)**	(13)	**(6)**	(15)
Net Change in Non-Cash Working Capital		**(92)**	(86)	**(76)**	(74)
Cash (Used in) Investing Activities		**(803)**	(788)	**(1,706)**	(1,620)
Net Cash Provided (Used) Before Financing Activities		**25**	180	**17**	13
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**(1)**	(66)	**(1)**	207
Proceeds on Issuance of Common Shares		**1**	1	**19**	32
Dividends Paid on Common Shares	8	**(183)**	(166)	**(367)**	(332)
Other		**-**	1	**-**	1
Cash From (Used in) Financing Activities		**(183)**	(230)	**(349)**	(92)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**5**	(1)	**(3)**	(7)
Increase (Decrease) in Cash and Cash Equivalents		**(153)**	(51)	**(335)**	(86)
Cash and Cash Equivalents, Beginning of Period		**978**	460	**1,160**	495
Cash and Cash Equivalents, End of Period		**825**	409	**825**	409

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of presentation for these interim Consolidated Financial Statements is found in Note 2.

The Company's 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, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

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

A) Results of Operations – Segment and Operational Information

For the three months ended June 30,	Oil Sands 2013	Oil Sands 2012	Conventional 2013	Conventional 2012	Refining and Marketing 2013	Refining and Marketing 2012
Revenues						
Gross Sales	**1,067**	917	**579**	465	**3,078**	2,962
Less: Royalties	**37**	26	**41**	39	**-**	-
	1,030	891	**538**	426	**3,078**	2,962
Expenses						
Purchased Product	**-**	-	**-**	-	**2,616**	2,508
Transportation and Blending	**415**	395	**45**	36	**-**	-
Operating	**189**	131	**135**	115	**138**	123
Production and Mineral Taxes	**-**	-	**9**	9	**-**	-
(Gain) Loss on Risk Management	**(8)**	(21)	**(16)**	(75)	**4**	(20)
Operating Cash Flow	**434**	386	**365**	341	**320**	351
Depreciation, Depletion and Amortization	**150**	110	**277**	222	**33**	35
Exploration Expense	**-**	-	**109**	68	**-**	-
Segment Income (Loss)	**284**	276	**(21)**	51	**287**	316

For the three months ended June 30,	Corporate and Eliminations 2013	Corporate and Eliminations 2012	Consolidated 2013	Consolidated 2012
Revenues				
Gross Sales	**(130)**	(65)	**4,594**	4,279
Less: Royalties	**-**	-	**78**	65
	(130)	(65)	**4,516**	4,214
Expenses				
Purchased Product	**(130)**	(65)	**2,486**	2,443
Transportation and Blending	**-**	-	**460**	431
Operating	**(1)**	-	**461**	369
Production and Mineral Taxes	**-**	-	**9**	9
(Gain) Loss on Risk Management	**(26)**	(169)	**(46)**	(285)
	27	169	**1,146**	1,247
Depreciation, Depletion and Amortization	**20**	12	**480**	379
Exploration Expense	**-**	-	**109**	68
Segment Income (Loss)	**7**	157	**557**	800
General and Administrative	**82**	56	**82**	56
Finance Costs	**124**	111	**124**	111
Interest Income	**(23)**	(27)	**(23)**	(27)
Foreign Exchange (Gain) Loss, net	**96**	25	**96**	25
(Gain) Loss on Divestiture of Assets	**-**	(1)	**-**	(1)
Other (Income) Loss, net	**(2)**	1	**(2)**	1
	277	165	**277**	165
Earnings Before Income Tax			**280**	635
Income Tax Expense			**101**	238
Net Earnings			**179**	397

B) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2013	2012	2013	2012	2013	2012
Revenues						
Gross Sales	1,049	909	414	365	1,463	1,274
Less: Royalties	36	26	39	38	75	64
	1,013	883	375	327	1,388	1,210
Expenses						
Transportation and Blending	415	395	41	31	456	426
Operating	181	125	81	67	262	192
Production and Mineral Taxes	-	-	9	8	9	8
(Gain) Loss on Risk Management	(7)	(15)	(7)	(7)	(14)	(22)
Operating Cash Flow	424	378	251	228	675	606

(1) *Includes natural gas liquids.*

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2013	2012	2013	2012	2013	2012
Revenues						
Gross Sales	10	7	163	99	173	106
Less: Royalties	1	-	2	1	3	1
	9	7	161	98	170	105
Expenses						
Transportation and Blending	-	-	4	5	4	5
Operating	4	4	54	48	58	52
Production and Mineral Taxes	-	-	-	1	-	1
(Gain) Loss on Risk Management	(1)	(6)	(9)	(68)	(10)	(74)
Operating Cash Flow	6	9	112	112	118	121

	Other					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2013	2012	2013	2012	2013	2012
Revenues						
Gross Sales	8	1	2	1	10	2
Less: Royalties	-	-	-	-	-	-
	8	1	2	1	10	2
Expenses						
Transportation and Blending	-	-	-	-	-	-
Operating	4	2	-	-	4	2
Production and Mineral Taxes	-	-	-	-	-	-
(Gain) Loss on Risk Management	-	-	-	-	-	-
Operating Cash Flow	4	(1)	2	1	6	-

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2013	2012	2013	2012	2013	2012
Revenues						
Gross Sales	1,067	917	579	465	1,646	1,382
Less: Royalties	37	26	41	39	78	65
	1,030	891	538	426	1,568	1,317
Expenses						
Transportation and Blending	415	395	45	36	460	431
Operating	189	131	135	115	324	246
Production and Mineral Taxes	-	-	9	9	9	9
(Gain) Loss on Risk Management	(8)	(21)	(16)	(75)	(24)	(96)
Operating Cash Flow	434	386	365	341	799	727

C) Geographic Information

	Canada		United States		Consolidated	
For the three months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**2,144**	1,809	**2,450**	2,470	**4,594**	4,279
Less: Royalties	**78**	65	**-**	-	**78**	65
	2,066	1,744	**2,450**	2,470	**4,516**	4,214
Expenses						
Purchased Product	**491**	421	**1,995**	2,022	**2,486**	2,443
Transportation and Blending	**460**	431	**-**	-	**460**	431
Operating	**330**	251	**131**	118	**461**	369
Production and Mineral Taxes	**9**	9	**-**	-	**9**	9
(Gain) Loss on Risk Management	**(53)**	(263)	**7**	(22)	**(46)**	(285)
	829	895	**317**	352	**1,146**	1,247
Depreciation, Depletion and Amortization	**447**	344	**33**	35	**480**	379
Exploration Expense	**109**	68	**-**	-	**109**	68
Segment Income	**273**	483	**284**	317	**557**	800

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

D) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**2,074**	2,019	**1,125**	1,057	**6,024**	5,954
Less: Royalties	**58**	92	**78**	95	**-**	-
	2,016	1,927	**1,047**	962	**6,024**	5,954
Expenses						
Purchased Product	**-**	-	**-**	-	**4,893**	5,097
Transportation and Blending	**926**	845	**92**	80	**-**	-
Operating	**359**	282	**271**	249	**275**	253
Production and Mineral Taxes	**-**	-	**19**	19	**-**	-
(Gain) Loss on Risk Management	**(38)**	(7)	**(48)**	(124)	**8**	(14)
Operating Cash Flow	**769**	807	**713**	738	**848**	618
Depreciation, Depletion and Amortization	**298**	225	**533**	458	**65**	73
Exploration Expense	**-**	-	**109**	68	**-**	-
Segment Income (Loss)	**471**	582	**71**	212	**783**	545

	Corporate and Eliminations		Consolidated	
For the six months ended June 30,	**2013**	2012	**2013**	2012
Revenues				
Gross Sales	**(252)**	(65)	**8,971**	8,965
Less: Royalties	**-**	-	**136**	187
	(252)	(65)	**8,835**	8,778
Expenses				
Purchased Product	**(252)**	(65)	**4,641**	5,032
Transportation and Blending	**-**	-	**1,018**	925
Operating	**(2)**	(1)	**903**	783
Production and Mineral Taxes	**-**	-	**19**	19
(Gain) Loss on Risk Management	**204**	(233)	**126**	(378)
	(202)	234	**2,128**	2,397
Depreciation, Depletion and Amortization	**39**	23	**935**	779
Exploration Expense	**-**	-	**109**	68
Segment Income (Loss)	**(241)**	211	**1,084**	1,550
General and Administrative	**165**	149	**165**	149
Finance Costs	**247**	224	**247**	224
Interest Income	**(50)**	(56)	**(50)**	(56)
Foreign Exchange (Gain) Loss, net	**148**	9	**148**	9
(Gain) Loss on Divestiture of Assets	**-**	(1)	**-**	(1)
Other (Income) Loss, net	**-**	(4)	**-**	(4)
	510	321	**510**	321
Earnings Before Income Tax			**574**	1,229
Income Tax Expense			**224**	406
Net Earnings			**350**	823

E) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**2,044**	1,996	**803**	819	**2,847**	2,815
Less: Royalties	**57**	91	**74**	92	**131**	183
	1,987	1,905	**729**	727	**2,716**	2,632
Expenses						
Transportation and Blending	**926**	844	**81**	69	**1,007**	913
Operating	**344**	263	**165**	146	**509**	409
Production and Mineral Taxes	**-**	-	**18**	17	**18**	17
(Gain) Loss on Risk Management	**(36)**	3	**(21)**	-	**(57)**	3
Operating Cash Flow	**753**	795	**486**	495	**1,239**	1,290

(1) *Includes natural gas liquids.*

	Natural Gas					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**18**	18	**317**	234	**335**	252
Less: Royalties	**1**	1	**4**	3	**5**	4
	17	17	**313**	231	**330**	248
Expenses						
Transportation and Blending	**-**	1	**11**	11	**11**	12
Operating	**9**	13	**105**	102	**114**	115
Production and Mineral Taxes	**-**	-	**1**	2	**1**	2
(Gain) Loss on Risk Management	**(2)**	(10)	**(27)**	(124)	**(29)**	(134)
Operating Cash Flow	**10**	13	**223**	240	**233**	253

	Other					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**12**	5	**5**	4	**17**	9
Less: Royalties	**-**	-	**-**	-	**-**	-
	12	5	**5**	4	**17**	9
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**6**	6	**1**	1	**7**	7
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**6**	(1)	**4**	3	**10**	2

	Total Upstream					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**2,074**	2,019	**1,125**	1,057	**3,199**	3,076
Less: Royalties	**58**	92	**78**	95	**136**	187
	2,016	1,927	**1,047**	962	**3,063**	2,889
Expenses						
Transportation and Blending	**926**	845	**92**	80	**1,018**	925
Operating	**359**	282	**271**	249	**630**	531
Production and Mineral Taxes	**-**	-	**19**	19	**19**	19
(Gain) Loss on Risk Management	**(38)**	(7)	**(48)**	(124)	**(86)**	(131)
Operating Cash Flow	**769**	807	**713**	738	**1,482**	1,545

F) Geographic Information

	Canada		United States		Consolidated	
For the six months ended June 30,	**2013**	2012	**2013**	2012	**2013**	2012
Revenues						
Gross Sales	**4,196**	4,053	**4,775**	4,912	**8,971**	8,965
Less: Royalties	**136**	187	**-**	-	**136**	187
	4,060	3,866	**4,775**	4,912	**8,835**	8,778
Expenses						
Purchased Product	**982**	964	**3,659**	4,068	**4,641**	5,032
Transportation and Blending	**1,018**	925	**-**	-	**1,018**	925
Operating	**640**	541	**263**	242	**903**	783
Production and Mineral Taxes	**19**	19	**-**	-	**19**	19
(Gain) Loss on Risk Management	**117**	(358)	**9**	(20)	**126**	(378)
	1,284	1,775	**844**	622	**2,128**	2,397
Depreciation, Depletion and Amortization	**870**	706	**65**	73	**935**	779
Exploration Expense	**109**	68	**-**	-	**109**	68
Segment Income	**305**	1,001	**779**	549	**1,084**	1,550

G) Joint Operations

A significant portion of the operating cash flows from the Oil Sands and Refining and Marketing segments are derived through jointly controlled entities, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), respectively. These joint arrangements, in which Cenovus has a 50 percent ownership interest, are classified as joint operations and, as such, Cenovus recognizes its share of the assets, liabilities, revenues and expenses.

FCCL, which is involved in the development and production of crude oil in Canada, is jointly controlled with ConocoPhillips and operated by Cenovus. WRB has two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with and operated by Phillips 66. Cenovus's share of operating cash flow from FCCL and WRB for the three months ended June 30, 2013 was $291 million and $323 million, respectively (three months ended June 30, 2012 – $273 million and $347 million). Cenovus's share of operating cash flow from FCCL and WRB for the six months ended June 30, 2013 was $512 million and $851 million, respectively (six months ended June 30, 2012 – $570 million and $615 million).

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

By Segment

	E&E (1)		PP&E (2)	
As at	**June 30, 2013**	December 31, 2012	**June 30, 2013**	December 31, 2012
Oil Sands	**1,295**	1,110	**8,446**	7,764
Conventional	**85**	175	**4,250**	4,929
Refining and Marketing	**-**	-	**3,248**	3,088
Corporate and Eliminations	**-**	-	**362**	371
Consolidated	**1,380**	1,285	**16,306**	16,152

	Goodwill		Total Assets	
As at	**June 30, 2013**	December 31, 2012	**June 30, 2013**	December 31, 2012
Oil Sands	**739**	739	**12,761**	11,972
Conventional	**-**	-	**4,879**	5,304
Refining and Marketing	**-**	-	**5,448**	5,018
Corporate and Eliminations	**-**	-	**1,402**	1,922
Consolidated	**739**	739	**24,490**	24,216

(1) Exploration and evaluation assets ("E&E").
(2) Property, plant and equipment ("PP&E").

By Geographic Region

	E&E		PP&E	
As at	**June 30, 2013**	December 31, 2012	**June 30, 2013**	December 31, 2012
Canada	**1,380**	1,285	**13,058**	13,065
United States	**-**	-	**3,248**	3,087
Consolidated	**1,380**	1,285	**16,306**	16,152

	Goodwill		Total Assets	
As at	**June 30, 2013**	December 31, 2012	**June 30, 2013**	December 31, 2012
Canada	**739**	739	**19,734**	19,744
United States	**-**	-	**4,756**	4,472
Consolidated	**739**	739	**24,490**	24,216

I) Capital Expenditures (1)

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2013**	2012	**2013**	2012
Capital				
Oil Sands	**531**	454	**1,208**	1,090
Conventional	**134**	129	**332**	360
Refining and Marketing	**26**	24	**51**	22
Corporate	**15**	53	**30**	88
	706	660	**1,621**	1,560
Acquisition Capital				
Oil Sands	**-**	-	**-**	-
Conventional	**1**	28	**4**	36
Refining and Marketing	**-**	-	**-**	-
Corporate	**-**	-	**-**	-
	707	688	**1,625**	1,596

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

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2012, except as identified in Note 3 and for income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. The disclosures provided are incremental to those included with the annual Consolidated Financial Statements. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2012, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective July 23, 2013.

3. CHANGES IN ACCOUNTING POLICIES

A) Joint Arrangements, Consolidation, Associates and Disclosures

As disclosed in the December 31, 2012 annual Consolidated Financial Statements, effective January 1, 2013, the Company 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 and WRB Refining LP, 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 the Company'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 the Company's share of the assets, liabilities, revenues and expenses have been recognized in the interim Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, the Company 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 the Company with the application of these standards.

B) Employee Benefits

As disclosed in the December 31, 2012 annual Consolidated Financial Statements, effective January 1, 2013, the Company adopted, as required, IAS 19, "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). The Company applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

The amendments require the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor approach' previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through comprehensive income. In addition, the Company 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 effect on the Consolidated Balance Sheets was as follows:

As at January 1, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) Composed of the defined benefit pension and other post-employment benefit ("OPEB") plans which are included in other liabilities on the Consolidated Balance Sheets.

As at December 31, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) Composed of the defined benefit pension and OPEB plans which are included in other liabilities on the Consolidated Balance Sheets.

The effect on the Consolidated Statements of Earnings and Comprehensive Income was as follows:

	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012	Year Ended December 31, 2012
Decrease in General and Administrative Expense	1	1	2
Decrease in Income Tax Expense	-	-	-
Increase in Net Earnings for the Period	1	1	2
Remeasurement of Defined Benefit and Other Post-Employment Benefits Liability	2	2	4
(Increase) in Income Tax Relating to Components of OCI (1)	-	-	-
(Decrease) in OCI (1)	(2)	(2)	(4)
(Decrease) in Comprehensive Income for the Period	(1)	(1)	(2)

(1) Other Comprehensive Income ("OCI").

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including net earnings per share.

Additional Disclosures

Details about the Company's defined benefit and other post-employment benefit ("OPEB") plans can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2012. Additional and restated disclosures as at December 31, 2012, as required by IAS 19R are as follows:

Defined Benefit and OPEB Plan Obligation and Funded Status

	Pension Benefits	OPEB
Defined Benefit Obligation		
Defined Benefit Obligation, January 1, 2012	84	19
Current Service Costs	10	2
Interest Costs on the Defined Benefit Obligation [(1)]	4	1
Benefits Paid	(2)	-
Plan Participant Contributions	1	-
Remeasurements:		
Actuarial (Gains) Losses from Experience Adjustments	3	1
Actuarial (Gains) Losses from Changes in Demographic Assumptions	-	(1)
Actuarial (Gains) Losses from Changes in Financial Assumptions	4	(2)
Plan Conversion	30	-
Defined Benefit Obligation, December 31, 2012	134	20
Plan Assets		
Balance as at December 31, 2011, as Previously Reported	61	-
Cumulative Effect of Change in Accounting Policy	(4)	-
Balance as at January 1, 2012, Restated	57	-
Return on Plan Assets [(1)]	3	-
Employer Contributions	22	-
Plan Participant Contributions	1	-
Benefits Paid	(2)	-
Remeasurements:		
Gains (Losses) on Plan Assets	1	-
Assets Transferred from Plan Conversion	12	-
Fair Value of Plan Assets, December 31, 2012	94	-
Pension and Other Post-Employment Benefit (Liability)	(40)	(20)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.

Plan Assets

Defined benefit plan assets comprise:

As at	December 31, 2012	January 1, 2012
Equity Securities		
Equity Funds and Balanced Funds	52	30
Other	3	-
Bond Funds	24	17
Non-Invested Assets	11	7
Real Estate	4	3
	94	57

Fair value of equity securities and bond funds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of real estate is determined by accredited real estate appraisers.

C) Fair Value Measurement

Effective January 1, 2013, the Company 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.

D) Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, the Company applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within 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.

E) Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, the Company complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosure can be found in Note 19. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

F) Future Accounting Pronouncements

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

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

4. FINANCE COSTS

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2013**	2012	**2013**	2012
Interest Expense – Short-Term Borrowings and Long-Term Debt	**66**	54	**132**	107
Interest Expense – Partnership Contribution Payable	**25**	30	**51**	62
Unwinding of Discount on Decommissioning Liabilities	**24**	21	**48**	42
Other	**9**	6	**16**	13
	124	111	**247**	224

5. INTEREST INCOME

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2013**	2012	**2013**	2012
Interest Income – Partnership Contribution Receivable	**(22)**	(26)	**(45)**	(54)
Other	**(1)**	(1)	**(5)**	(2)
	(23)	(27)	**(50)**	(56)

6. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the period ended June 30,	Three Months Ended **2013**	2012	Six Months Ended **2013**	2012
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued from Canada	**169**	69	**267**	7
U.S. Dollar Partnership Contribution Receivable Issued from Canada	**(72)**	(55)	**(123)**	(31)
Other	**(13)**	(5)	**(10)**	2
Unrealized Foreign Exchange (Gain) Loss	**84**	9	**134**	(22)
Realized Foreign Exchange (Gain) Loss	**12**	16	**14**	31
	96	25	**148**	9

7. INCOME TAXES

The provision for income taxes is as follows:

For the period ended June 30,	Three Months Ended **2013**	2012	Six Months Ended **2013**	2012
Current Tax				
Canada	**57**	21	**87**	83
United States	**4**	13	**58**	25
Total Current Tax	**61**	34	**145**	108
Deferred Tax	**40**	204	**79**	298
	101	238	**224**	406

8. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the period ended June 30, ($ millions, except net earnings per share)	Three Months Ended **2013**	2012	Six Months Ended **2013**	2012
Net Earnings – Basic and Diluted	**179**	397	**350**	823
Weighted Average Number of Shares – Basic	**755.8**	755.7	**755.9**	755.4
Dilutive Effect of Cenovus TSARs	**1.3**	2.2	**1.9**	3.4
Dilutive Effect of NSRs	**-**	-	**-**	-
Weighted Average Number of Shares – Diluted	**757.1**	757.9	**757.8**	758.8
Net Earnings Per Share – Basic	**$0.24**	$0.53	**$0.46**	$ 1.09
Net Earnings Per Share – Diluted	**$0.24**	$0.52	**$0.46**	$ 1.08

B) Dividends Per Share

The Company paid dividends of $367 million or $0.484 per share for the six months ended June 30, 2013 (June 30, 2012 – $332 million, $0.44 per share). The Cenovus Board of Directors declared a third quarter dividend of $0.242 per share, payable on September 30, 2013, to common shareholders of record as of September 13, 2013.

9. INVENTORIES

As at	June 30, 2013	December 31, 2012
Product		
Refining and Marketing	**1,149**	1,056
Oil Sands	**193**	202
Conventional	**1**	1
Parts and Supplies	**35**	29
	1,378	1,288

10. ASSETS AND LIABILITIES HELD FOR SALE

As at	June 30, 2013	December 31, 2012
Assets Held for Sale		
Property, Plant and Equipment	**303**	-
Liabilities Related to Assets Held for Sale		
Decommissioning Liabilities	**30**	-

During the three months ended March 31, 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 assets were recorded at the lesser of fair value less costs to sell and their carrying amount, and depletion ceased. These assets and the related liabilities are reported in the Conventional segment.

In June 2013, the Company entered into an agreement with an unrelated third party to sell the Lower Shaunavon asset. The sale was completed on July 3, 2013, for proceeds of $240 million plus closing adjustments. As at June 30, 2013, an impairment loss of $57 million was recorded as additional depreciation, depletion and amortization. The Company continues to market certain of its Bakken properties.

11. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2011	880
Additions [(1)]	687
Transfers to PP&E (Note 12)	(218)
Exploration Expense	(68)
Divestitures	(11)
Change in Decommissioning Liabilities	15
As at December 31, 2012	1,285
Additions	221
Transfers to PP&E (Note 12)	(80)
Exploration Expense	(46)
Divestitures	(1)
Change in Decommissioning Liabilities	1
As at June 30, 2013	**1,380**

(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

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

Additions to E&E assets for the six months ended June 30, 2013 include $24 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2012 – $37 million). Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the six months ended June 30, 2013 or for the year ended December 31, 2012.

For the six months ended June 30, 2013, $80 million of E&E assets were transferred to PP&E – development and production assets following the determination of technical feasibility and commercial viability of the projects in question (year ended December 31, 2012 – $218 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. During the six months ended June 30, 2013, $46 million of previously capitalized E&E costs related to certain tight oil exploration assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense.

12. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [1]	Total
COST					
As at December 31, 2011	23,858	194	3,425	576	28,053
Additions	2,442	44	118	191	2,795
Transfers from E&E Assets (Note 11)	218	-	-	-	218
Transfers and Reclassifications	-	-	(55)	-	(55)
Change in Decommissioning Liabilities	484	-	(16)	-	468
Exchange Rate Movements	1	-	(73)	-	(72)
As at December 31, 2012	27,003	238	3,399	767	31,407
Additions	1,303	20	51	30	1,404
Transfers from E&E Assets (Note 11)	80	-	-	-	80
Transfers and Reclassifications	(500)	-	(15)	-	(515)
Change in Decommissioning Liabilities	(267)	-	-	-	(267)
Exchange Rate Movements	-	-	193	-	193
As at June 30, 2013	**27,619**	**258**	**3,628**	**797**	**32,302**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2011	13,021	139	225	344	13,729
Depreciation and Depletion Expense	1,368	19	146	52	1,585
Transfers and Reclassifications	-	-	(55)	-	(55)
Impairment Losses	-	-	-	-	-
Exchange Rate Movements	1	-	(5)	-	(4)
As at December 31, 2012	14,390	158	311	396	15,255
Depreciation and Depletion Expense	757	15	65	39	876
Transfers and Reclassifications	(141)	-	(15)	-	(156)
Impairment Losses	2	-	-	-	2
Exchange Rate Movements	-	-	19	-	19
As at June 30, 2013	**15,008**	**173**	**380**	**435**	**15,996**
CARRYING VALUE					
As at December 31, 2011	10,837	55	3,200	232	14,324
As at December 31, 2012	12,613	80	3,088	371	16,152
As at June 30, 2013	**12,611**	**85**	**3,248**	**362**	**16,306**

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

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $86 million for the six months ended June 30, 2013 (year ended December 31, 2012 – $161 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the six months ended June 30, 2013 or for the year ended December 31, 2012.

PP&E includes the following amounts in respect of assets under construction and are not subject to depreciation, depletion and amortization:

As at	June 30, 2013	December 31, 2012
Development and Production	50	38
Refining Equipment	53	13
Other	-	11
	103	62

13. LONG-TERM DEBT

As at	June 30, 2013	December 31, 2012
Revolving Term Debt [(1)]	-	-
U.S. Dollar Denominated Unsecured Notes	4,993	4,726
Total Debt Principal	4,993	4,726
Debt Discounts and Transaction Costs	(45)	(47)
	4,948	4,679

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

As at June 30, 2013 the Company is in compliance with all of the terms of its debt agreements.

On May 9, 2013, Cenovus amended its U.S. base shelf prospectus for unsecured notes to increase the total capacity from $2.0 billion to $3.25 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at June 30, 2013, US$2.0 billion remains under this U.S. shelf prospectus. The U.S. shelf prospectus expires in July 2014.

14. DECOMMISSIONING LIABILITIES

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

As at	June 30, 2013	December 31, 2012
Decommissioning Liabilities, Beginning of Year	2,315	1,777
Liabilities Incurred	28	99
Liabilities Settled	(42)	(66)
Transfers and Reclassifications	(30)	3
Change in Estimated Future Cash Flows	-	144
Change in Discount Rate	(294)	273
Unwinding of Discount on Decommissioning Liabilities	48	86
Foreign Currency Translation	2	(1)
Decommissioning Liabilities, End of Period	2,027	2,315

The undiscounted amount of estimated cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.9 percent as at June 30, 2013 (December 31, 2012 – 4.2 percent).

15. SHARE CAPITAL

A) Authorized

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

B) Issued and Outstanding

As at	June 30, 2013 Number of Common Shares (thousands)	June 30, 2013 Amount	December 31, 2012 Number of Common Shares (thousands)	December 31, 2012 Amount
Outstanding, Beginning of Year	755,843	3,829	754,499	3,780
Common Shares Issued under Stock Option Plans	635	21	1,344	49
Common Shares Cancelled	(650)	(3)	-	-
Outstanding, End of Period	755,828	3,847	755,843	3,829

During the six months ended June 30, 2013, the Company cancelled 650,000 common shares. The common shares were held in reserve for un-exchanged shares of Alberta Energy Company Ltd., pursuant to the merger of Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002 ("AEC Merger"), in which Encana Corporation ("Encana") was formed. Due to the plan of arrangement in 2009 involving Encana Corporation and Cenovus, common shares of the Company were held in reserve until the tenth anniversary of the AEC Merger.

There were no preferred shares outstanding as at June 30, 2013 (December 31, 2012 – nil).

As at June 30, 2013, there were 22 million (December 31, 2012 – 28 million) common shares available for future issuance under stock option plans.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at June 30, 2013	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
Balance, Beginning of Year	(26)	95	-	69
Other Comprehensive Income, Before Tax	11	72	10	93
Income Tax	(2)	-	(2)	(4)
Balance, End of Period	(17)	167	8	158

As at June 30, 2012	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
Balance, Beginning of Year	(22)	119	-	97
Other Comprehensive Income, Before Tax	(2)	9	-	7
Income Tax	-	-	-	-
Balance, End of Period	(24)	128	-	104

17. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Options issued under the plan have associated tandem stock appreciation rights ("TSARs") or net settlement rights ("NSRs"). The following table is a summary of the options outstanding at the end of the period.

As at June 30, 2013	Issued	Term (Years)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	Closing Share Price ($)	Number of Units Outstanding (thousands)
NSRs	On or After February 24, 2011	7	5.91	35.45	30.00	25,828
TSARs	Prior to February 17, 2010	5	0.62	26.64	30.00	3,355
TSARs	On or After February 17, 2010	7	3.70	26.71	30.00	4,751
Encana Replacement TSARs held by Cenovus Employees	Prior to December 1, 2009	5	0.61	29.40	17.79	4,166
Cenovus Replacement TSARs held by Encana Employees	Prior to December 1, 2009	5	0.61	26.58	30.00	2,672

NSRs

The weighted average unit fair value of NSRs granted during the six months ended June 30, 2013 was $6.16 before considering forfeitures, which are required to be considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model.

The following table summarizes information related to the NSRs:

As at June 30, 2013	Number of NSRs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	15,074	37.52
Granted	11,037	32.67
Exercised for Common Shares	-	-
Forfeited	(283)	37.42
Outstanding, End of Period	25,828	35.45
Exercisable, End of Period	5,616	37.71

TSARs Held by Cenovus Employees

The Company has recorded a liability of $38 million at June 30, 2013 (December 31, 2012 – $64 million) based on the fair value of each TSAR held by Cenovus employees. The intrinsic value of vested TSARs held by Cenovus employees as at June 30, 2013 was $28 million (December 31, 2012 – $45 million).

The following table summarizes information related to the TSARs, including Performance TSARs, held by Cenovus employees. All Performance TSARs have vested and, as such, terms and conditions are consistent with TSARs which were not performance based.

As at June 30, 2013	Number of TSARs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	11,251	28.13
Exercised for Cash Payment	(1,301)	31.12
Exercised as Options for Common Shares	(620)	30.62
Forfeited	(41)	28.78
Expired	(1,183)	33.48
Outstanding, End of Period	8,106	26.68
Exercisable, End of Period	7,931	26.60

For options exercised during the period, the weighted average market price of Cenovus's common shares at the date of exercise was $31.73.

Encana Replacement TSARs Held by Cenovus Employees

The Company has recorded a liability of $nil as at June 30, 2013 (December 31, 2012 – $1 million) based on the fair value of each Encana Replacement TSAR held by Cenovus employees. The intrinsic value of vested Encana Replacement TSARs held by Cenovus employees at June 30, 2013 was $nil (December 31, 2012 – $nil).

The following table summarizes information related to the Encana Replacement TSARs, including Performance TSARs held by Cenovus employees. All Performance TSARs have vested and, as such, terms and conditions are consistent with TSARs which were not performance based.

As at June 30, 2013	**Number of TSARs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**7,722**	**32.66**
Forfeited	**(106)**	**30.96**
Expired	**(3,450)**	**36.64**
Outstanding, End of Period	**4,166**	**29.40**
Exercisable, End of Period	**4,166**	**29.40**

The closing price of Encana common shares on the TSX as at June 30, 2013 was $17.79.

Cenovus Replacement TSARs Held by Encana Employees

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

The Company has recorded a liability of $11 million as at June 30, 2013 (December 31, 2012 – $35 million) based on the fair value of each Cenovus Replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. The intrinsic value of vested Cenovus Replacement TSARs held by Encana employees at June 30, 2013 was $10 million (December 31, 2012 – $22 million).

The following table summarizes the information related to the Cenovus Replacement TSARs, including Performance TSARs, held by Encana employees. All Performance TSARs have vested and, as such, terms and conditions are consistent with TSARs which were not performance based.

As at June 30, 2013	**Number of TSARs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**5,229**	**29.29**
Exercised for Cash Payment	**(1,252)**	**30.93**
Exercised as Options for Common Shares	**(15)**	**29.59**
Forfeited	**(8)**	**34.22**
Expired	**(1,282)**	**33.30**
Outstanding, End of Period	**2,672**	**26.58**
Exercisable, End of Period	**2,672**	**26.58**

For options exercised during the period, the weighted average market price of Cenovus's common shares at the date of exercise was $33.31.

B) Performance Share Units

The Company has recorded a liability of $85 million as at June 30, 2013 (December 31, 2012 – $124 million) for performance share units ("PSUs") based on the market value of Cenovus's common shares at June 30, 2013. As PSUs are paid out upon vesting, the intrinsic value was $nil at June 30, 2013 and December 31, 2012.

The following table summarizes the information related to the PSUs held by Cenovus employees.

As at June 30, 2013	Number of PSUs (thousands)
Outstanding, Beginning of Year	5,258
Granted	2,552
Paid Out	(2,008)
Cancelled	(75)
Units in Lieu of Dividends	86
Outstanding, End of Period	**5,813**

C) Deferred Share Units

The Company has recorded a liability of $35 million as at June 30, 2013 (December 31, 2012 – $36 million) for deferred share units ("DSUs") based on the market value of Cenovus's common shares at June 30, 2013. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees.

As at June 30, 2013	Number of DSUs (thousands)
Outstanding, Beginning of Year	1,084
Granted to Directors	63
Granted from Annual Bonus Awards	8
Units in Lieu of Dividends	18
Redeemed	(1)
Outstanding, End of Period	**1,172**

D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses:

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2013**	2012	**2013**	2012
NSRs	9	5	16	13
TSARs Held by Cenovus Employees	(6)	(20)	(14)	(4)
Encana Replacement TSARS Held by Cenovus Employees	-	1	-	1
PSUs	1	6	16	21
DSUs	(1)	(4)	(1)	2
Stock-Based Compensation Expense (Recovery)	**3**	(12)	**17**	33

18. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and

Amortization ("Adjusted EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

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

As at	**June 30, 2013**	December 31, 2012
Long-Term Debt	**4,948**	4,679
Shareholders' Equity	**9,906**	9,782
Capitalization	**14,854**	14,461
Debt to Capitalization	**33%**	32%

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

As at	**June 30, 2013**	December 31, 2012
Debt	**4,948**	4,679
Net Earnings	**522**	995
Add (Deduct):		
Finance Costs	**478**	455
Interest Income	**(103)**	(109)
Income Tax Expense	**601**	783
Depreciation, Depletion and Amortization	**1,741**	1,585
Goodwill Impairment	**393**	393
E&E Impairment	**46**	68
Unrealized (Gain) Loss on Risk Management	**380**	(57)
Foreign Exchange (Gain) Loss, net	**119**	(20)
(Gain) Loss on Divestitures of Assets	**1**	-
Other (Income) Loss, net	**(1)**	(5)
Adjusted EBITDA (1)	**4,177**	4,088
Debt to Adjusted EBITDA	**1.2x**	1.1x

(1) *Calculated on a trailing 12 month basis.*

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

At June 30, 2013, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$2.0 billion under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

As at June 30, 2013, Cenovus is in compliance with all of the terms of its debt agreements.

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Financial Assets and Liabilities

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

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

The Company's risk management assets and liabilities consist of crude oil, natural gas and power purchase contracts. Crude oil and natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period end forward price for the same commodity, using quoted market prices or the period end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The forward prices used in the determination of the fair value of the power purchase contracts at June 30, 2013 range from $49.25 to $93.25 per Megawatt Hour.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period end trading prices of long-term borrowings on the secondary market (Level 2). As at June 30, 2013, the carrying value of Cenovus's long-term debt was $4,948 million and the fair value was $5,382 million (December 31, 2012 carrying value – $4,679 million, fair value – $5,582 million).

Available for sale financial assets, which comprise private equity investments, are carried at fair value. When fair value cannot be reliably measured, these assets are carried at cost. Fair value is determined based on recent private placement transactions (Level 3) when available. Available for sale assets are included in other assets on the Consolidated Balance Sheets.

B) Risk Management Assets and Liabilities

Net Risk Management Position

As at	June 30, 2013	December 31, 2012
Risk Management Assets		
Current Asset	85	283
Long-Term Asset	8	5
	93	288
Risk Management Liabilities		
Current Liability	11	17
Long-Term Liability	2	1
	13	18
Net Risk Management Asset (Liability)	80	270

Summary of Unrealized Risk Management Positions

	June 30, 2013			December 31, 2012		
		Risk Management			Risk Management	
As at	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	57	12	45	221	16	205
Natural Gas	33	-	33	66	1	65
Power	3	1	2	1	1	-
Fair Value	93	13	80	288	18	270

Financial assets and liabilities are only offset if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. Cenovus has pledged cash collateral of $21 million (December 31, 2012 – $12 million) with respect to certain of these risk management contracts, which has not been offset against the related financial liability. The following table provides a summary of the Company's offsetting risk management positions:

	June 30, 2013			December 31, 2012		
		Risk Management			Risk Management	
As at	Asset	Liability	Net	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	118	38	80	306	36	270
Amount Offset	(25)	(25)	-	(18)	(18)	-
Net Amount per Consolidated Financial Statements	93	13	80	288	18	270

Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions

As at	June 30, 2013	December 31, 2012
Prices Sourced from Observable Data or Market Corroboration (Level 2)	**78**	270
Prices Determined from Unobservable Inputs (Level 3)	**2**	-
	80	270

Net Fair Value of Commodity Price Positions at June 30, 2013

	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price [1]	18,500 bbls/d	2013	110.36 US$/bbl	**34**
Brent Fixed Price [1]	18,500 bbls/d	2013	111.72 C$/bbl	**18**
Brent Fixed Price	9,000 bbls/d	2014	100.35 US$/bbl	**9**
Brent Fixed Price	6,000 bbls/d	2014	103.81 C$/bbl	**1**
WCS Differential [2]	49,000 bbls/d	2013	(20.74) US$/bbl	**(18)**
WCS Differential [2]	14,900 bbls/d	2014	(20.39) US$/bbl	**5**
Other Financial Positions [3]				**(4)**
Crude Oil Fair Value Position				**45**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	166 MMcf/d	2013	4.64 US$/Mcf	**32**
Other Fixed Price Contracts [4]				**1**
Natural Gas Fair Value Position				**33**
Power Purchase Contracts				
Power Fair Value Position				**2**

(1) Brent fixed price positions consist of both Brent fixed price swaps and WTI swaps converted to Brent.
(2) Cenovus entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.
(3) Other financial positions are part of ongoing operations to market the Company's production.
(4) Cenovus entered into other fixed price contracts to protect against widening price differentials between production areas and various sales points.

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

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2013**	2012	**2013**	2012
Realized Gain (Loss) [1]				
Crude Oil	**11**	26	**54**	-
Natural Gas	**8**	75	**27**	135
Refining	**(4)**	17	**(8)**	12
Power	**5**	(2)	**5**	(2)
	20	116	**78**	145
Unrealized Gain (Loss) [2]				
Crude Oil	**21**	261	**(169)**	291
Natural Gas	**6**	(97)	**(36)**	(61)
Refining	**(3)**	5	**(1)**	8
Power	**2**	-	**2**	(5)
	26	169	**(204)**	233
Gain (Loss) on Risk Management	**46**	285	**(126)**	378

(1) Realized gains and (losses) on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and (losses) on risk management are recorded in the Corporate and Eliminations segment.

Reconciliation of Unrealized Risk Management Positions from January 1 to June 30, 2013

	2013		2012
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**270**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Period	**(126)**	**(126)**	378
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**14**		
Fair Value of Contracts Realized During the Period	**(78)**	**(78)**	(145)
Fair Value of Contracts, End of Period	**80**	**(204)**	233

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices on the Company's open risk management positions as at June 30, 2013 could have resulted in unrealized gains (losses) impacting earnings before income tax for the six months ended June 30, 2013 as follows:

Risk Management Positions in Place as at June 30, 2013

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent and WTI Hedges	**(151)**	**151**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	**83**	**(83)**
Natural Gas Commodity Price	± $1 per Mcf Applied to NYMEX Natural Gas Hedges	**(32)**	**32**
Natural Gas Basis Price	± $0.10 per Mcf Applied to Natural Gas Basis Hedges	**-**	**-**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to a number of risks associated with its financial assets and liabilities. These risks include commodity price risk, credit risk, liquidity risk, foreign exchange risk and interest rate risk. The Company has several practices and policies in place to help mitigate these risks.

A description of the nature and extent of risks arising from the Company's financial assets and liabilities can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2012. The Company's exposure to these risks has not changed significantly since December 31, 2012.

20. COMMITMENTS AND CONTINGENCIES

A) Commitments

During the six months ended June 30, 2013 the Company entered into various firm transportation agreements totaling approximately $10 billion. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement.

B) Legal Proceedings

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)	2013			2012					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Gross Sales									
Upstream	**3,199**	**1,646**	1,553	6,156	1,584	1,496	**3,076**	1,382	1,694
Refining and Marketing	**6,024**	**3,078**	2,946	11,356	2,336	3,066	**5,954**	2,962	2,992
Corporate and Eliminations	**(252)**	**(130)**	(122)	(283)	(118)	(100)	**(65)**	(65)	-
Less: Royalties	**136**	**78**	58	387	78	122	**187**	65	122
Revenues	**8,835**	**4,516**	4,319	16,842	3,724	4,340	**8,778**	4,214	4,564
Operating Cash Flow									
Crude Oil and Natural Gas Liquids									
Foster Creek	**421**	**232**	189	924	246	227	**451**	223	228
Christina Lake	**169**	**96**	73	343	118	93	**132**	70	62
Pelican Lake	**163**	**96**	67	418	98	108	**212**	85	127
Conventional	**486**	**251**	235	962	240	227	**495**	228	267
Natural Gas	**233**	**118**	115	513	134	126	**253**	121	132
Other Upstream Operations	**10**	**6**	4	9	5	2	**2**	-	2
	1,482	**799**	683	3,169	841	783	**1,545**	727	818
Refining and Marketing	**848**	**320**	528	1,267	122	527	**618**	351	267
Operating Cash Flow (1)	**2,330**	**1,119**	1,211	4,436	963	1,310	**2,163**	1,078	1,085
Cash Flow Information									
Cash from Operating Activities	**1,723**	**828**	895	3,420	758	1,029	**1,633**	968	665
Deduct (Add back):									
Net Change in Other Assets and Liabilities	**(65)**	**(31)**	(34)	(113)	(42)	(19)	**(52)**	(20)	(32)
Net Change in Non-Cash Working Capital	**(54)**	**(12)**	(42)	(110)	103	(69)	**(144)**	63	(207)
Cash Flow (2)	**1,842**	**871**	971	3,643	697	1,117	**1,829**	925	904
Per Share - Basic	**2.44**	**1.15**	1.28	4.82	0.92	1.48	**2.42**	1.22	1.20
- Diluted	**2.43**	**1.15**	1.28	4.80	0.92	1.47	**2.41**	1.22	1.19
Operating Earnings (3)	**646**	**255**	391	868	(188)	432	**624**	284	340
Per Share - Diluted	**0.85**	**0.34**	0.52	1.14	(0.25)	0.57	**0.82**	0.37	0.45
Net Earnings	**350**	**179**	171	995	(117)	289	**823**	397	426
Per Share - Basic	**0.46**	**0.24**	0.23	1.32	(0.15)	0.38	**1.09**	0.53	0.56
- Diluted	**0.46**	**0.24**	0.23	1.31	(0.15)	0.38	**1.08**	0.52	0.56
Effective Tax Rates using									
Net Earnings	**39.0%**			44.1%					
Operating Earnings, excluding Divestitures	**29.9%**			47.0%					
Canadian Statutory Rate	**25.2%**			25.2%					
U.S. Statutory Rate	**38.5%**			38.5%					
Foreign Exchange Rates *(US$ per C$1)*									
Average	**0.984**	**0.977**	0.992	1.001	1.009	1.005	**0.994**	0.990	0.999
Period end	**0.951**	**0.951**	0.985	1.005	1.005	1.017	**0.981**	0.981	1.001

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

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

(3) Operating earnings is a non-GAAP measure defined as net earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

Financial Metrics (Non-GAAP measures)	2013			2012					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Debt to Capitalization (4), (5)	**33%**	**33%**	33%	32%	32%	32%	**27%**	27%	28%
Debt to Adjusted EBITDA (5), (6)	**1.2x**	**1.2x**	1.1x	1.1x	1.1x	1.1x	**1.0x**	1.0x	1.0x
Return on Capital Employed (7)	**5%**	**5%**	7%	9%	9%	11%	**14%**	14%	16%
Return on Common Equity (8)	**5%**	**5%**	8%	10%	10%	14%	**17%**	17%	21%

(4) Capitalization is a non-GAAP measure defined as debt plus shareholders' equity.

(5) Debt includes the Company's 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.

(6) We define trailing 12-month Adjusted EBITDA as adjusted earnings before finance costs, interest income, income tax expense, DD&A, impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net.

(7) Calculated, on a trailing 12-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.

(8) Calculated, on a trailing 12-month basis, as net earnings divided by average shareholders' equity.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Common Share Information	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Common Shares Outstanding *(millions)*									
Period end	**755.8**	**755.8**	755.8	755.8	755.8	755.8	**755.7**	755.7	755.6
Average - Basic	**755.9**	**755.8**	756.0	755.6	755.8	755.7	**755.4**	755.7	755.1
Average - Diluted	**757.8**	**757.1**	758.4	758.5	758.3	758.0	**758.8**	757.9	759.5
Price Range *($ per share)*									
TSX - C$									
High	**34.13**	**32.08**	34.13	39.64	35.69	36.25	**39.64**	36.68	39.64
Low	**28.32**	**28.32**	31.67	30.09	31.82	30.37	**30.09**	30.09	33.24
Close	**30.00**	**30.00**	31.46	33.29	33.29	34.31	**32.37**	32.37	35.90
NYSE - US$									
High	**34.50**	**31.58**	34.50	39.81	36.11	37.31	**39.81**	37.26	39.81
Low	**27.25**	**27.25**	30.58	28.83	31.74	30.20	**28.83**	28.83	32.45
Close	**28.52**	**28.52**	30.99	33.54	33.54	34.85	**31.80**	31.80	35.94
Dividends Paid *($ per share)*	**$ 0.484**	**$ 0.242**	$ 0.242	$ 0.88	$ 0.22	$ 0.22	**$ 0.44**	$ 0.22	$ 0.22
Share Volume Traded *(millions)*	**356.4**	**201.6**	154.9	664.3	141.7	152.6	**370.0**	192.6	177.4

Net Capital Investment	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Capital Investment *($ millions)*									
Oil Sands									
Foster Creek	**399**	**189**	210	735	208	199	**328**	169	159
Christina Lake	**337**	**162**	175	593	168	147	**278**	140	138
Total	**736**	**351**	385	1,328	376	346	**606**	309	297
Pelican Lake	**254**	**111**	143	518	147	128	**243**	104	139
Other Oil Sands	**218**	**69**	149	365	82	42	**241**	41	200
	1,208	**531**	677	2,211	605	516	**1,090**	454	636
Conventional	**332**	**134**	198	848	257	231	**360**	129	231
Refining and Marketing	**51**	**26**	25	118	58	38	**22**	24	(2)
Corporate	**30**	**15**	15	191	58	45	**88**	53	35
Capital Investment	**1,621**	**706**	915	3,368	978	830	**1,560**	660	900
Acquisitions [(1)]	**4**	**1**	3	114	70	8	**36**	28	8
Divestitures	**(1)**	**-**	(1)	(76)	(11)	-	**(65)**	1	(66)
Net Acquisition and Divestiture Activity	**3**	**1**	2	38	59	8	**(29)**	29	(58)
Net Capital Investment	**1,624**	**707**	917	3,406	1,037	838	**1,531**	689	842

(1) Q4 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

Operating Statistics - Before Royalties

Upstream Production Volumes	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*									
Oil Sands - Heavy Oil									
Foster Creek	**55,665**	**55,338**	55,996	57,833	59,059	63,245	**54,477**	51,740	57,214
Christina Lake	**41,388**	**38,459**	44,351	31,903	41,808	32,380	**26,655**	28,577	24,733
Total	**97,053**	**93,797**	100,347	89,736	100,867	95,625	**81,132**	80,317	81,947
Pelican Lake	**23,824**	**23,959**	23,687	22,552	23,507	23,539	**21,570**	22,410	20,730
	120,877	**117,756**	124,034	112,288	124,374	119,164	**102,702**	102,727	102,677
Conventional Liquids									
Heavy Oil	**16,497**	**16,284**	16,712	16,015	16,243	15,492	**16,163**	15,703	16,624
Light and Medium Oil	**37,317**	**36,137**	38,508	36,071	36,034	35,695	**36,280**	36,149	36,411
Natural Gas Liquids [(2)]	**961**	**950**	971	1,029	995	999	**1,061**	987	1,138
Total Crude Oil and Natural Gas Liquids	**175,652**	**171,127**	180,225	165,403	177,646	171,350	**156,206**	155,566	156,850
Natural Gas *(MMcf/d)*									
Oil Sands	**22**	**24**	20	33	30	27	**37**	33	41
Conventional	**518**	**512**	525	561	536	550	**579**	563	595
Total Natural Gas	**540**	**536**	545	594	566	577	**616**	596	636
Total Production *(BOE/d)*	**265,652**	**260,460**	271,058	264,403	271,979	267,517	**258,873**	254,899	262,850

(2) Natural gas liquids include condensate volumes.

Average Royalty Rates *(excluding impact of Realized Gain (Loss) on Risk Management)*	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Oil Sands									
Foster Creek	**4.5%**	**5.7%**	2.9%	11.8%	8.0%	19.1%	**9.7%**	4.6%	13.9%
Christina Lake	**5.6%**	**5.6%**	5.7%	6.2%	5.7%	5.3%	**7.1%**	7.2%	7.0%
Pelican Lake	**6.0%**	**5.8%**	6.2%	5.0%	4.5%	6.6%	**4.4%**	4.2%	4.5%
Conventional									
Weyburn	**19.3%**	**20.3%**	18.3%	20.7%	17.9%	19.8%	**22.4%**	21.4%	23.3%
Other	**5.9%**	**6.0%**	5.7%	7.2%	7.1%	6.6%	**7.6%**	6.8%	8.3%
Natural Gas Liquids	**1.1%**	**2.5%**	0.2%	2.0%	2.3%	2.5%	**1.7%**	1.7%	1.7%
Natural Gas	**1.4%**	**1.2%**	1.7%	1.2%	0.9%	0.8%	**1.6%**	0.4%	2.5%

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Refining	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Refinery Operations [1]									
Crude oil capacity [2] *(Mbbls/d)*	**457**	**457**	457	452	452	452	**452**	452	452
Crude oil runs *(Mbbls/d)*	**428**	**439**	416	412	311	442	**448**	451	445
Heavy Oil	**214**	**230**	197	198	155	210	**214**	229	199
Light/Medium	**214**	**209**	219	214	156	232	**234**	222	246
Crude utilization	**94%**	**96%**	91%	91%	69%	98%	**99%**	100%	98%
Refined products *(Mbbls/d)*	**448**	**457**	439	433	330	463	**469**	473	465

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

(2) The official nameplate capacity of Wood River increased effective January 1, 2013.

Selected Average Benchmark Prices	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
Brent Futures	**107.88**	**103.35**	112.64	111.68	110.13	109.42	**113.61**	108.76	118.45
West Texas Intermediate ("WTI")	**94.26**	**94.17**	94.36	94.15	88.23	92.20	**98.15**	93.35	103.03
Average Differential Brent Futures-WTI	**13.62**	**9.18**	18.28	17.53	21.90	17.22	**15.46**	15.41	15.42
Western Canadian Select ("WCS")	**68.70**	**75.01**	62.40	73.12	70.12	70.48	**76.01**	70.48	81.61
Differential - WTI-WCS	**25.56**	**19.16**	31.96	21.03	18.11	21.72	**22.14**	22.87	21.42
Condensate - (C5 @ Edmonton)	**104.33**	**101.45**	107.23	100.88	98.14	96.12	**104.70**	99.32	110.16
Differential - WTI-Condensate (premium)/discount	**(10.07)**	**(7.28)**	(12.87)	(6.73)	(9.91)	(3.92)	**(6.55)**	(5.97)	(7.13)
Refining Margins 3-2-1 Crack Spreads [3] *(US$/bbl)*									
Chicago	**29.30**	**31.06**	27.53	27.76	28.18	35.64	**23.60**	28.20	19.00
Midwest Combined (Group 3)	**27.59**	**27.24**	27.93	28.56	28.49	35.99	**24.89**	28.28	21.50
Natural Gas Prices									
AECO *($/GJ)*	**3.16**	**3.40**	2.92	2.28	2.90	2.08	**2.06**	1.74	2.39
NYMEX *(US$/MMBtu)*	**3.71**	**4.09**	3.34	2.79	3.40	2.81	**2.48**	2.22	2.74
Differential - NYMEX-AECO *(US$/MMBtu)*	**0.42**	**0.56**	0.27	0.38	0.31	0.61	**0.30**	0.39	0.21

(3) 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 ("LIFO").

Per-unit Results *(excluding impact of Realized Gain (Loss) on Risk Management)*	2013			2012					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Heavy Oil - Foster Creek [4] *($/bbl)*									
Price	**60.21**	**68.17**	52.60	64.55	59.93	63.95	**67.46**	63.83	70.71
Royalties	**2.64**	**3.87**	1.47	7.36	4.55	11.79	**6.38**	2.85	9.54
Transportation and Blending	**0.99**	**0.04**	1.89	2.41	2.91	2.38	**2.16**	1.91	2.38
Operating	**15.08**	**16.19**	14.03	11.99	11.26	11.50	**12.68**	12.49	12.85
Netback	**41.50**	**48.07**	35.21	42.79	41.21	38.28	**46.24**	46.58	45.94
Heavy Oil - Christina Lake [4] *($/bbl)*									
Price	**41.94**	**52.61**	33.41	47.73	43.37	52.91	**48.32**	44.57	52.58
Royalties	**2.15**	**2.71**	1.69	2.72	2.32	2.61	**3.12**	2.90	3.37
Transportation and Blending	**4.02**	**4.45**	3.67	3.79	3.00	4.00	**4.30**	4.12	4.51
Operating	**14.66**	**16.83**	12.93	12.95	11.42	13.59	**13.84**	12.52	15.33
Netback	**21.11**	**28.62**	15.12	28.27	26.63	32.71	**27.06**	25.03	29.37
Heavy Oil - Pelican Lake [4] ($/bbl)									
Price	**63.52**	**72.32**	54.30	69.23	64.37	66.75	**73.00**	66.42	78.50
Royalties	**3.66**	**4.08**	3.22	3.34	2.82	4.34	**3.06**	2.68	3.37
Transportation and Blending	**2.33**	**2.58**	2.07	2.15	1.23	1.09	**3.18**	3.54	2.88
Operating	**20.75**	**22.21**	19.23	17.08	17.20	17.47	**16.81**	17.71	16.05
Netback	**36.78**	**43.45**	29.78	46.66	43.12	43.85	**49.95**	42.49	56.20
Heavy Oil - Oil Sands [4] ($/bbl)									
Price	**54.60**	**64.09**	45.92	60.84	55.11	61.71	**63.83**	59.00	68.36
Royalties	**2.67**	**3.55**	1.88	5.22	3.47	7.85	**4.81**	2.83	6.66
Transportation and Blending	**2.29**	**1.98**	2.57	2.74	2.63	2.52	**2.93**	2.87	2.99
Operating	**16.06**	**17.67**	14.59	13.33	12.41	13.29	**13.90**	13.61	14.18
Netback	**33.58**	**40.89**	26.88	39.55	36.60	38.05	**42.19**	39.69	44.53
Heavy Oil - Conventional [4] ($/bbl)									
Price	**66.02**	**70.81**	61.62	70.53	64.73	68.04	**74.65**	67.70	80.64
Royalties	**7.10**	**7.67**	6.57	10.06	8.68	8.81	**11.35**	9.36	13.06
Transportation and Blending	**3.01**	**2.59**	3.39	2.17	2.34	2.31	**2.02**	2.26	1.81
Operating	**17.72**	**17.38**	18.04	15.21	11.68	16.48	**16.41**	15.07	17.57
Production and Mineral Taxes	**0.30**	**0.30**	0.30	0.24	0.31	0.27	**0.19**	0.25	0.14
Netback	**37.89**	**42.87**	33.32	42.85	41.72	40.17	**44.68**	40.76	48.06
Total Heavy Oil [4] ($/bbl)									
Price	**55.99**	**64.91**	47.82	62.05	56.22	62.45	**65.29**	60.13	70.08
Royalties	**3.21**	**4.05**	2.45	5.83	4.07	7.96	**5.69**	3.68	7.56
Transportation and Blending	**2.38**	**2.06**	2.67	2.67	2.60	2.50	**2.81**	2.79	2.82
Operating	**16.26**	**17.63**	15.01	13.56	12.33	13.66	**14.24**	13.80	14.65
Production and Mineral Taxes	**0.04**	**0.04**	0.04	0.03	0.04	0.03	**0.03**	0.03	0.02
Netback	**34.10**	**41.13**	27.65	39.96	37.18	38.30	**42.52**	39.83	45.03
Light and Medium Oil ($/bbl)									
Price	**81.68**	**86.84**	76.77	78.99	75.27	76.06	**82.36**	76.16	88.45
Royalties	**7.81**	**8.61**	7.05	8.09	6.92	7.53	**8.97**	7.98	9.94
Transportation and Blending	**3.87**	**4.37**	3.39	2.65	2.39	2.36	**2.92**	3.02	2.83
Operating	**16.29**	**16.32**	16.26	15.51	15.63	16.27	**15.06**	14.76	15.36
Production and Mineral Taxes	**2.55**	**2.64**	2.46	2.44	2.51	2.35	**2.46**	2.34	2.57
Netback	**51.16**	**54.90**	47.61	50.30	47.82	47.55	**52.95**	48.06	57.75

(4) Heavy oil price and transportation and blending costs exclude the costs of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for 2013 YTD is as follows: Foster Creek - $44.34/bbl; Christina Lake - $49.54/bbl; Pelican Lake - $18.49/bbl; Heavy Oil - Oil Sands - $41.00/bbl; Heavy Oil - Conventional - $15.66/bbl and Total Heavy Oil - $37.93/bbl.

Operating Statistics - Before Royalties (continued)

Per-unit Results

(excluding impact of Realized Gain (Loss) on Risk Management)	2013			2012					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Total Crude Oil *($/bbl)*									
Price	**61.57**	**69.75**	54.02	65.76	60.10	65.37	**69.23**	63.91	74.22
Royalties	**4.21**	**5.05**	3.43	6.32	4.65	7.87	**6.45**	4.69	8.10
Transportation and Blending	**2.70**	**2.57**	2.82	2.66	2.55	2.47	**2.83**	2.84	2.83
Operating	**16.27**	**17.34**	15.27	13.99	13.00	14.22	**14.43**	14.03	14.81
Production and Mineral Taxes	**0.58**	**0.61**	0.56	0.56	0.54	0.53	**0.59**	0.58	0.59
Netback	**37.81**	**44.18**	31.94	42.23	39.36	40.28	**44.93**	41.77	47.89
Natural Gas Liquids *($/bbl)*									
Price	**57.72**	**46.44**	68.88	69.54	65.89	61.53	**75.08**	65.52	83.36
Royalties	**0.64**	**1.17**	0.12	1.42	1.52	1.55	**1.30**	1.13	1.45
Netback	**57.08**	**45.27**	68.76	68.12	64.37	59.98	**73.78**	64.39	81.91
Total Liquids *($/bbl)*									
Price	**61.55**	**69.61**	54.10	65.79	60.13	65.35	**69.26**	63.92	74.28
Royalties	**4.19**	**5.03**	3.42	6.29	4.64	7.83	**6.41**	4.67	8.05
Transportation and Blending	**2.69**	**2.55**	2.81	2.65	2.54	2.45	**2.81**	2.82	2.81
Operating	**16.18**	**17.24**	15.19	13.90	12.93	14.14	**14.33**	13.93	14.71
Production and Mineral Taxes	**0.58**	**0.61**	0.55	0.56	0.54	0.53	**0.58**	0.57	0.59
Netback	**37.91**	**44.18**	32.13	42.39	39.48	40.40	**45.13**	41.93	48.12
Total Natural Gas *($/Mcf)*									
Price	**3.38**	**3.50**	3.25	2.42	2.97	2.30	**2.22**	1.92	2.50
Royalties	**0.05**	**0.04**	0.05	0.03	0.02	0.02	**0.03**	0.01	0.06
Transportation and Blending	**0.12**	**0.08**	0.15	0.10	0.10	0.08	**0.11**	0.08	0.13
Operating	**1.15**	**1.16**	1.14	1.10	1.29	1.08	**1.03**	0.98	1.08
Production and Mineral Taxes	**0.01**	**(0.01)**	0.03	0.01	(0.01)	0.02	**0.02**	0.02	0.02
Netback	**2.05**	**2.23**	1.88	1.18	1.57	1.10	**1.03**	0.83	1.21
Total [(1)] *($/BOE)*									
Price	**47.40**	**52.55**	42.52	46.60	45.50	46.61	**47.17**	43.25	50.84
Royalties	**2.85**	**3.35**	2.38	4.00	3.08	5.02	**3.96**	2.84	5.00
Transportation and Blending	**2.00**	**1.82**	2.17	1.88	1.86	1.74	**1.95**	1.90	2.00
Operating	**13.00**	**13.64**	12.39	11.18	11.12	11.35	**11.12**	10.75	11.46
Production and Mineral Taxes	**0.40**	**0.38**	0.42	0.38	0.33	0.38	**0.40**	0.40	0.40
Netback	**29.15**	**33.36**	25.16	29.16	29.11	28.12	**29.74**	27.36	31.98
Impact of Long-Term Incentives Costs (Recovery) on Operating Costs ($/BOE)	**0.09**	**0.07**	0.10	0.16	0.05	0.32	**0.14**	(0.17)	0.42
Impact of Realized Gain (Loss) on Risk Management									
Liquids *($/bbl)*	**1.71**	**0.72**	2.62	1.39	3.35	2.02	**(0.07)**	1.64	(1.67)
Natural Gas *($/Mcf)*	**0.28**	**0.18**	0.39	1.14	0.89	1.24	**1.20**	1.39	1.03
Total [(1)] *($/BOE)*	**1.70**	**0.84**	2.52	3.42	4.05	3.98	**2.81**	4.27	1.44

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

ADVISORY

FINANCIAL INFORMATION

Basis of Presentation Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS).

NON-GAAP MEASURES

This quarterly report contains references to non-GAAP measures as follows:

- Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains, less realized losses on risk management activities and is used to provide a consistent measure of the cash generating performance of the company's assets and improves the comparability of Cenovus's underlying financial performance between periods.
- 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, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim and annual consolidated financial statements.
- 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. Management views operating earnings as a better measure of performance than net earnings because the excluded items reduce the comparability of the company's underlying financial performance between periods. The majority of the U.S. dollar debt issued from Canada has maturity dates in excess of five years.
- Free cash flow is defined as cash flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.
- Debt to capitalization and debt to adjusted EBITDA are two ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion, excluding any amounts with respect to the partnership contribution payable and receivable. Capitalization is a non-GAAP measure defined as debt plus shareholders' equity. Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, asset impairments, unrealized gain or loss on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss, calculated on a trailing 12-month basis.

These measures have been described and presented in this quarterly report in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. For further information, refer to Cenovus's most recent Management's Discussion & Analysis (MD&A) available at cenovus.com.

OIL & GAS INFORMATION

The estimates of total bitumen initially-in-place and all subcategories thereof and the associated recovery factors were prepared effective December 31, 2012 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator (IQRE), and are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook (COGEH). The estimates of exploitable bitumen in-place (EBIP) were also prepared effective December 31, 2012 by the IQRE. The term "exploitable bitumen in-place" is not presently a COGEH defined term; however, the definition contained herein was provided by the IQRE and is derived from and consistent with the current draft proposed COGEH terminology. The term "best estimate", when used in reference to a BIIP estimate, is not defined in COGEH; however, it was determined by the IQRE to the same 50% confidence level as was applied to estimates of probable reserves and best estimate contingent resources.

The IQRE evaluation of Cenovus's reserves and bitumen contingent resources as at December 31, 2009 was compliant with the U.S. Securities and Exchange Commission (SEC) requirements, using 12 month average constant prices and costs. An IQRE evaluation using McDaniel January 1, 2010 forecast prices and costs did not produce a materially different result.

For further discussion regarding our contingent resources, see our 2012 Annual Information Form (AIF), available on SEDAR at sedar.com and at cenovus.com. Actual resources may be greater or less than the estimates provided. The following definitions accompany the disclosure contained herein:

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate.

Total bitumen initially-in-place (BIIP) (equivalent to "total resources") is that quantity of bitumen that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations, prior to production (discovered BIIP), plus those estimated quantities in accumulations yet to be discovered (undiscovered BIIP).

Discovered BIIP (equivalent to "discovered resources") is that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered BIIP includes production, reserves, and contingent resources; the remainder is categorized as unrecoverable. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. There is no certainty that it will be commercially viable to produce any portion of the estimate.

Commercial discovered BIIP is that quantity of discovered BIIP that has met the essential social, environmental, and economic conditions, including political, legal, regulatory, and contractual conditions, to be considered capable of commercial production and includes production and reserves.

Production is the cumulative quantity of bitumen that has been recovered at a given date.

Reserves are estimated remaining quantities of bitumen anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development and production status.

Proved Reserves are those quantities of bitumen, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations.

Probable Reserves are those additional reserves quantities of bitumen that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

Sub-commercial discovered BIIP is that quantity of discovered BIIP that has not met all of the essential social, environmental, and economic conditions, including political, legal, regulatory, and contractual conditions, to be capable of commercial production and includes contingent resources and unrecoverable discovered BIIP.

Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The McDaniel estimates of contingent resources have not been adjusted for risk based on the chance of development.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. Economic contingent resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina

Lake. Other regional analogs are used for contingent resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. COGEH identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican. Further information in respect of contingencies faced in these regions is included in our AIF.

Unrecoverable is that portion of discovered BIIP or undiscovered BIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered BIIP (equivalent to "undiscovered resources") is that quantity of bitumen that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered BIIP is referred to as prospective resources, the remainder is categorized as unrecoverable.

Prospective resources are those quantities of bitumen petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

Exploitable bitumen in-place (EBIP) is the estimated volume of bitumen, before any production has been removed, which is contained in a subsurface stratigraphic interval that meets or exceeds certain reservoir characteristics considered necessary for the application of known recovery technologies. Examples of such reservoir characteristics include continuous net pay, porosity, and mass bitumen content.

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", "objective", "projected", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, projections contained in our updated 2013 guidance, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, broadening market access, improving cost structures, anticipated finding and development costs, expected reserves, contingent, prospective and bitumen initially-in-place resources estimates, bitumen recovery estimation, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

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 relationships with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our most recent AIF/Form 40-F, "Risk Management" in our current and annual MD&A and risk factors described in other documents we file from time to time with securities regulatory authorities, all of which are available on SEDAR at sedar.com, EDGAR at www.sec.gov and 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.

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