News release

# Cenovus oil sands production increases 14% in 2013
## Proved bitumen reserves up 8%

- Combined oil sands production at Foster Creek and Christina Lake averaged almost 103,000 barrels per day (bbls/d) net in 2013, up 14% from 2012.
- Production at Christina Lake increased 55% to more than 49,000 bbls/d net in 2013. Christina Lake phase D reached full capacity in 2013, about six months after first production. Phase E is expected to achieve full capacity in the first quarter of 2014.
- Foster Creek production averaged more than 53,000 bbls/d net in 2013, down 8% from 2012.
- Proved bitumen reserves at the end of 2013 were more than 1.8 billion barrels (bbls), up 8% from 2012.
- Refining operations achieved a 97% utilization rate and increased processing of heavy crude oil by 12% to 222,000 bbls/d.
- Cash flow was $3.6 billion in 2013, comparable with the previous year.
- The Board of Directors approved a dividend increase of 10% for the first quarter of 2014, resulting in a quarterly dividend of $0.2662 per share.

"We had another year of solid reserves and production growth as well as strong performance from our refining business," said Brian Ferguson, Cenovus President & Chief Executive Officer. "We continue to effectively execute our long-term business plan. The strength of our operations and balance sheet allows us to concentrate on growing total shareholder return, including our commitment to a dividend growth strategy."

**Production & financial summary**

| (for the period ended December 31) Production (before royalties) | **2013 Q4** | 2012 Q4 | % change | **2013 Full Year** | 2012 Full Year | % change |
|---|---|---|---|---|---|---|
| Oil sands total (bbls/d) | **113,890** | 100,867 | 13 | **102,500** | 89,736 | 14 |
| Conventional oil[1] (bbls/d) | **74,853** | 76,779 | -3 | **76,775** | 75,667 | 1 |
| **Total oil** (bbls/d) | **188,743** | 177,646 | 6 | **179,275** | 165,403 | 8 |
| Natural gas (MMcf/d) | **514** | 566 | -9 | **529** | 594 | -11 |
| Financial ($ millions, except per share amounts) | | | | | | |
| Cash flow[2] | **835** | 697 | 20 | **3,609** | 3,643 | -1 |
| Per share diluted | **1.10** | 0.92 | | **4.76** | 4.80 | |
| Operating earnings[2] | **212** | -188 | - | **1,171** | 868 | 35 |
| Per share diluted | **0.28** | -0.25 | | **1.55** | 1.14 | |
| Net earnings | **-58** | -117 | 50 | **662** | 995 | -33 |
| Per share diluted | **-0.08** | -0.15 | | **0.87** | 1.31 | |
| Capital investment | **898** | 978 | -8 | **3,262** | 3,368 | -3 |

[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 (February 13, 2014)** – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) continued to deliver on its commitments in 2013, increasing oil sands production 14% and maintaining a strong balance sheet as it expanded its oil operations. In addition, the company's refining operations again performed well, generating significant operating cash flow to support Cenovus's long-term business plan. Cenovus also achieved solid growth in its oil reserves.

The increase in production from the company's oil sands operations in 2013 was largely driven by its Christina Lake project. Christina Lake volumes increased 55% as phase D reached full production capacity and phase E, the company's 10th oil sands phase, began production in July. The company expects to achieve full production capacity from this phase in the first quarter of 2014. The successful addition of these phases further demonstrates the importance of the company's manufacturing approach to developing its oil sands assets. Cenovus expects Christina Lake to achieve production of between 124,000 bbls/d and 136,000 bbls/d gross this year. This represents production volumes of 95% of design capacity, which the company is targeting for the current phases.

"We have an excellent track record of delivering oil sands projects on schedule and at industry-leading capital efficiencies," Ferguson said. "We plan to continue our disciplined approach to developing our oil sands assets."

Higher production at Christina Lake more than offset an 8% year-over-year decline in volumes at Foster Creek. The decrease at Foster Creek was partially the result of catching up on well maintenance that was deferred in 2012. In addition, the evolution to common steam chambers in the initial project areas at Foster Creek prompted Cenovus to evaluate its long-term reservoir management plan and apply new techniques to optimize production performance. This includes determining the optimal reservoir pressure, drilling more wells using Wedge Well™ technology and moving more wells to the final stage of production, which is called the blowdown stage. Blowdown enables the company to move steam from older well pads that no longer need it for continued production to new areas of the reservoir. For the fourth quarter of 2013, Foster Creek output was in line with company expectations.

Total conventional oil production, including the heavy oil operation at Pelican Lake, averaged almost 77,000 bbls/d for the year, up 1%. Pelican Lake production increased 8%, from the previous year, due to infill drilling in 2012 and 2013. The company also achieved increased production volumes from its horizontal well program in southern Alberta. These increases were offset by the July sale of the Shaunavon tight oil assets in Saskatchewan, which resulted in a production decline of approximately 2,300 bbls/d on an annual basis compared with 2012.

### Integrated operations provide financial stability

The company generated cash flow of $3.6 billion in 2013, in line with the previous year. Cenovus's integrated strategy, which combines upstream oil production with downstream refining capacity, provides protection against volatile light-heavy oil differentials. Integration acts as a natural economic hedge against discounted heavy crude prices by providing lower feedstock costs to the company's refineries.

The company's two jointly owned refineries performed well in 2013 and generated operating cash flow in excess of capital invested of approximately $1 billion, net to Cenovus. Operating cash flow was negatively affected by declines in market crack spreads and higher costs for renewable identification numbers (RINs). Market crack spreads were more than 20% lower for the year compared with 2012. The cost of RINs increased to $153 million, net to Cenovus in 2013, an almost five-fold increase from the previous year. Refineries that do not blend renewable fuels such as ethanol into their gasoline and diesel are required to purchase RINs in the open market to comply with the Renewable Fuel Standards set by the U.S. Environmental Protection Agency (EPA). The EPA has proposed reducing biofuel blending quotas for 2014, which has led to a significant drop in the cost of RINs recently.

The impact of lower market crack spreads and higher RIN costs was substantially offset by strong operational performance from Cenovus's refining assets in 2013. The company's refineries processed 222,000 bbls/d of heavy oil, up 12% from 2012, the highest level since Cenovus became joint owner of the Wood River and Borger facilities in 2007. The ability to process higher volumes of less expensive heavy oil resulted in an improved feedstock cost advantage. Total refined product output increased 7% to average 463,000 bbls/d in 2013.

**Continued additions to reserves and contingent resources**

Cenovus continued to strengthen its reserves and resources base. The company's proved bitumen reserves increased 8% to more than 1.8 billion bbls at the end of 2013, according to its independent reserves and contingent resources evaluation. Total proved reserves reached almost 2.3 billion barrels of oil equivalent (BOE) in 2013, up 5% from the previous year, resulting in a 214% production replacement ratio.

Proved plus probable bitumen reserves increased 6% to more than 2.5 billion bbls, while the company's total proved plus probable reserves increased 4% to 3.2 billion BOE. Economic bitumen best estimate contingent resources increased 2% from 2012 to 9.8 billion bbls. Cenovus's 2013 proved finding and development (F&D) costs, excluding changes in future development costs, were $14.51/BOE compared with $9.04/BOE in 2012. The three-year average was $9.05/BOE. The 2013 recycle ratio was 2.2 times.

**Capital investment focused on existing projects**

The company's long-term business plan of creating shareholder value by increasing its planned capacity to approximately 525,000 bbls/d of net oil production within the next decade remains on track. In support of that, Cenovus invested approximately $3.3 billion to grow its business in 2013. Almost $1.5 billion was invested last year in Cenovus's two operating oil sands projects, Christina Lake and Foster Creek. Cenovus began construction of the phase A plant at its Narrows Lake project late in 2013, investing $152 million for the year.

Total capital investment in 2013 declined by 3% from 2012 primarily due to lower spending on Cenovus's conventional business after the sale of its Shaunavon tight oil assets and a slowing of investment at Pelican Lake.

Cenovus's successful delivery of oil sands projects to date is largely attributable to its manufacturing approach to development. This includes constructing projects in templated and repeatable phases to help manage cost, quality and scheduling. As well, the company plans to continue to invest in its future by assessing its resource base and drilling more than

300 gross stratigraphic test wells in each of the next five years. This helps Cenovus to better define existing reservoirs and lays the groundwork for potential future reserves additions and project expansions.

Cenovus expects to invest between $2.8 billion and $3.1 billion in 2014, a 10% decrease from 2013. The company has built a large inventory of regulatory approved projects and is now allocating more of its capital to develop this established inventory. This includes projects now under construction at Foster Creek, Christina Lake and Narrows Lake, as well as Grand Rapids and Telephone Lake, which are anticipated to receive regulatory approval in 2014.

**Foster Creek expansion update**

The company has adjusted its timeline for achieving total expected production capacity at Foster Creek phases F, G and H. The total capacity numbers include the initial design capacity plus additional barrels anticipated to result from optimization. That optimization work focuses on the entire facility rather than individual phases. Optimization of the steam to oil ratio (SOR) can be achieved through innovations such as the use of Cenovus's Wedge Well™ technology, optimizing reservoir pressures and effectively moving well pads to blowdown as they mature. Plant optimization can be accomplished through debottlenecking and facility upgrades such as improving the fluid handling capability at the plant.

As a result of the steam chamber changes mentioned earlier, the company intends to delay the optimization until it's had more time to assess its new operating procedures. That means the optimization volumes are no longer expected to coincide with the start of production at each new phase.

Cenovus expects phases F, G and H to ramp up to a combined 90,000 bbls/d gross – the initial design capacity. Once those phases are complete, as planned in 2016, the company anticipates moving ahead with the optimization work. Optimization is anticipated to take about three years and bring the project up to its expected total full production capacity for phases A though H.

"Our confidence in Foster Creek and the reservoir's ability to eventually produce more than 300,000 barrels per day gross remains unchanged," Ferguson said. "This is one of the best SAGD projects in the industry. As we move forward, we'll be focusing our capital at Foster Creek on investment that will bring the best value to shareholders."

**Attacking cost structures**

Cenovus continues to seek efficiencies across its organization to ensure it remains a cost leader.

"We're working hard to drive down costs," said John Brannan, Executive Vice-President & Chief Operating Officer. "We've centralized some of our operational activities and we're identifying opportunities in all areas of our operations to reduce capital and operating expenses."

Cost saving initiatives include improving waste treatment processes, drilling and workover procedures and optimizing chemical usage. The company's cost reduction strategy also includes reducing the number of planned new hires in 2014 compared with 2013 and reallocating staff to support oil projects already producing and those under construction.

Operating costs per barrel at Foster Creek were higher in 2013 compared with 2012, primarily due to increased well workover activities, higher fuel and workforce costs and lower production volumes. At Pelican Lake, operating costs per barrel in 2013 also rose from 2012 primarily due to increased polymer use. Operating costs per barrel at Christina Lake declined in 2013 from the previous year due to higher production volumes.

**Expanding market access**

Cenovus is concentrating on finding new customers in North America and around the world and working to ensure it has the ability to move its oil to these customers.

In 2013, the company committed to move 200,000 bbls/d on the proposed Energy East pipeline. It has additional shipping capacity of 175,000 bbls/d on proposed pipelines to the West Coast and 150,000 bbls/d on planned pipelines to the U.S. Gulf Coast, which is evenly split between Enbridge's Flanagan South and TransCanada's Keystone XL systems.

In addition to using pipelines, the company sold an average of 6,150 bbls/d of conventional oil that was transported by rail in 2013. By the end of 2013, Cenovus had rail capacity to transport 10,000 bbls/d of oil. Cenovus plans to begin using additional rail cars to transport some of its oil sands production by mid-2014 and expects to start taking delivery of 825 coiled and insulated leased rail cars in late 2014.

As part of its rail strategy, Cenovus entered into two multi-year terminal agreements in 2013. The company has contracted with Canexus for bitumen blend and unit train loading services at Bruderheim, Alberta as well as for rail loading services with US Development Group/Gibson Energy's Hardisty, Alberta facility. Ultimately, the company expects to have the capacity to move up to 30,000 bbls/d of its blended oil volumes using rail by the end of 2014.

# Oil Projects

| Daily production[1] (Before royalties) (Mbbls/d) | 2013 | | | | | 2012 | | | | | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Full Year** | **Q4** | Q3 | Q2 | Q1 | Full Year | Q4 | Q3 | Q2 | Q1 | Full Year |
| **Oil sands** | | | | | | | | | | | |
| Foster Creek | **53** | **52** | 49 | 55 | 56 | 58 | 59 | 63 | 52 | 57 | 55 |
| Christina Lake | **49** | **61** | 53 | 38 | 44 | 32 | 42 | 32 | 29 | 25 | 12 |
| Oil sands total | **103** | **114** | 102 | 94 | 100 | 90 | 101 | 96 | 80 | 82 | 67 |
| **Conventional oil** | | | | | | | | | | | |
| Pelican Lake | **24** | **25** | 25 | 24 | 24 | 23 | 24 | 24 | 22 | 21 | 20 |
| Weyburn | **16** | **16** | 16 | 16 | 17 | 16 | 16 | 16 | 16 | 17 | 16 |
| Other conventional[2] | **36** | **34** | 34 | 37 | 39 | 37 | 37 | 36 | 36 | 38 | 31 |
| Conventional total | **77** | **75** | 75 | 77 | 80 | 76 | 77 | 76 | 75 | 75 | 68 |
| **Total oil** | **179** | **189** | 177 | 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 operations currently producing, 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 is currently building its third major oil sands project at Narrows Lake, which is part of the Christina Lake Region. These projects are operated by Cenovus and jointly owned with ConocoPhillips. Cenovus 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.

### Foster Creek and Christina Lake

**Production**

- Combined oil sands production at Foster Creek and Christina Lake increased 14% to 102,500 bbls/d net in 2013 from the previous year. Fourth quarter production also rose 13% in 2013 to almost 114,000 bbls/d net, compared with the same period a year earlier.
- Christina Lake production averaged 49,310 bbls/d net for the year, a 55% increase. Christina Lake produced an average of 61,471 bbls/d net in the fourth quarter, an increase of 47% from the same period in 2012.
- The significant increase at Christina Lake is the result of phase D reaching full capacity in the first quarter of 2013 and the addition of phase E, which achieved first oil production in mid-July. Phase E is expected to reach its design capacity during the

first quarter of 2014. The five phases now in operation have a gross production capacity of 138,000 bbls/d and are expected to achieve average utilization of approximately 95%.

- The SOR at Christina Lake was 1.8 in 2013, an improvement from 1.9 in 2012.
- Foster Creek production averaged 53,190 bbls/d net in 2013, an 8% decrease compared with 2012. The decline was partially due to work to clear a backlog of well maintenance deferred in 2012. In addition, Cenovus continues to assess its operating procedures to optimize steam allocation and production as the reservoir supporting phases A to E evolves into common steam chambers.
- Foster Creek production in the fourth quarter was in line with the company's expectations as the project ramped up following a planned major turnaround in the fall and well maintenance work was completed. December production averaged 57,383 bbls/d net. Total fourth quarter production was 52,419 bbls/d net, down 11% from the same period in 2012.
- Foster Creek's 2013 SOR was 2.5, up from 2.2 in 2012, partially as a result of the changes discussed earlier regarding the evolution of the steam chambers. Cenovus expects an average SOR of 2.6 to 3.0 at Foster Creek in 2014 as reflected in the company's updated guidance. The higher SOR is a result of a recent change in the start-up process for phase F, which is expected to begin production in the third quarter of this year. The company now plans to inject steam into the wells and circulate it for a longer period before initial production. Cenovus anticipates this will result in long-term production benefits that outweigh the added costs of a temporarily higher SOR.

**Expansions**

- At Christina Lake, the phase F expansion is on schedule and on budget with about 44% of the project complete and engineering, procurement and plant construction work continuing. Engineering work also continues for phase G at Christina Lake. First production is expected from phase F in 2016 and phase G in 2017.
- At Foster Creek, phase F is on schedule and on budget with 90% of the project complete and first production expected in the third quarter of 2014, with full ramp up to be completed 12 to 18 months after first production begins. Phase G is 66% complete with initial production expected in 2015. Phase H is 35% complete and first production is expected in 2016.
- Combined capital investment at Foster Creek and Christina Lake was about $1.5 billion in 2013, up 12% from approximately $1.3 billion in 2012.

**Operating costs**

- Operating costs at Christina Lake were $12.47/bbl in 2013, a 4% decrease from $12.95/bbl the previous year. This was due to the increase in production from phases D and E. The decrease in per-barrel operating costs was partially offset by higher costs due to increased fuel consumption and prices, increased expenses associated with an expanded workforce for the new phases, repairs and maintenance, as well as fluid, waste handling and trucking costs. Non-fuel operating costs at Christina Lake were $9.44/bbl in 2013, a 10% decrease from $10.53/bbl in 2012.
- Operating costs at Foster Creek averaged $15.77/bbl in 2013, a 32% increase from $11.99/bbl in the same period last year. The increase was primarily due to lower production volumes, higher workover activities and increased cost from higher fuel

prices and consumption. As well, there were higher workforce costs due to the hiring of additional field staff ahead of the start-up of phase F expected in the third quarter of 2014. Non-fuel operating costs at Foster Creek were $12.89/bbl for 2013 compared with $9.96/bbl in 2012, a 29% increase.

- Cenovus has updated its 2014 guidance for operating costs to a range of $16.40/bbl to $17.75/bbl at Foster Creek. The increase is a result of costs associated with bringing on phase F as well as additional preventative well maintenance, an anticipated increase in fuel prices, and higher expected SORs as the company implements its new reservoir management procedures.

**Narrows Lake**

- Overall progress for phase A at Narrows Lake, Cenovus's next major oil sands development, was 16% complete at the end of the year. The first phase of the project is anticipated to have production capacity of 45,000 bbls/d gross, with first oil production expected in 2017. Site construction, engineering and procurement are progressing as expected.
- Narrows Lake is expected to be the industry's first project to demonstrate solvent aided process (SAP), using butane, on a commercial scale.
- Cenovus invested $152 million to advance the Narrows Lake project in 2013.

## 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 the second quarter of 2014.
- A dewatering pilot project designed to remove an underground layer of non-potable water sitting on top of the oil sands deposit at Telephone Lake was successfully concluded during the fourth quarter. Approximately 70% of the top water was removed during the pilot and replaced with compressed air.
- 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.
- Cenovus invested $93 million in its Telephone Lake project in 2013, a decrease from $138 million in 2012. Capital investment decreased with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012.

**Grand Rapids**

- At the company's 100%-owned Grand Rapids project, located within the Greater Pelican Region, work continues on a SAGD pilot project with two well pairs in production.
- Cenovus completed a turnaround at Grand Rapids during the third quarter to resolve facility constraints that affected production on both well pairs in the first half of 2013.
- A regulatory application and EIA for the 180,000 bbl/d commercial project has been submitted and Cenovus anticipates receiving regulatory approval in the first quarter of 2014.

- Capital investment at Grand Rapids was $39 million in 2013, down from $65 million in the previous year, primarily due to drilling fewer stratigraphic test wells.

## 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. Cenovus has been injecting polymer since 2006 to enhance production from the reservoir, which is also under waterflood.

- Pelican Lake produced an average of 24,254 bbls/d for the year, an 8% increase from 2012 due to additional infill wells coming on production and increased response from the polymer flood. Fourth quarter production was 24,528 bbls/d, a 4% increase from the same period in 2012.
- Cenovus invested $465 million at Pelican Lake in 2013, primarily for the infill drilling and polymer flood programs. Capital investment at Pelican Lake was down 10% from 2012 as the company decided to slow the pace of development to better match production growth experienced at the project.
- Operating costs at Pelican Lake averaged $20.65/bbl for the year, a 21% increase from $17.08/bbl a year earlier, mainly due to increased polymer consumption related to the expansion of the polymer flood and higher workover and repairs and maintenance activities as well as increased electricity costs resulting from both higher prices and consumption.

### 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.

- Conventional oil production, excluding Pelican Lake, averaged 52,521 bbls/d in 2013, down 1% compared with 2012. The slight decrease was mainly due to the July sale of the company's Shaunavon tight oil assets in Saskatchewan, partially offset by strong horizontal well performance from the company's conventional drilling program. Shaunavon produced an annual average of 2,095 bbls/d in 2013 compared with 4,411 bbls/d in 2012. Other conventional oil production primarily included:
    - average production in Alberta of 32,542 bbls/d, a 7% increase compared with 2012, primarily due to successful horizontal well drilling on fee lands
    - average production at the Weyburn operation in Saskatchewan of 16,361 bbls/d, compared with 16,278 bbls/d in 2012.
- Cenovus invested $704 million in its conventional oil assets, excluding Pelican Lake, for the year, focusing on its emerging tight oil plays in Alberta.
- Operating cash flow from conventional oil assets, excluding Pelican Lake, in excess of capital investment was $299 million in 2013, an increase of 90% from 2012.
- Operating costs for Cenovus's other conventional oil operations were $16.24/bbl in 2013, an increase of 7% from $15.12/bbl in 2012. This was mainly due to higher workforce, increased well workover on high-return wells to mitigate production declines as well as rising electricity costs due to higher market rates and increased

consumption. Increased costs were partially offset by declines in repairs and maintenance mostly due to the Shaunavon assets sale.

## Natural Gas

| Daily production | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| (Before royalties) (MMcf/d) | 2013 | | | | | 2012 | | | | | 2011 |
| | **Full Year** | **Q4** | Q3 | Q2 | Q1 | Full Year | Q4 | Q3 | Q2 | Q1 | Full Year |
| Natural gas | **529** | **514** | 523 | 536 | 545 | 594 | 566 | 577 | 596 | 636 | 656 |

Cenovus has a solid base of established, reliable natural gas properties in Alberta. These properties are important components of the company's financial foundation and are managed as financial assets, not production assets, 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.

- The company invested $27 million in its natural gas properties during the year. Operating cash flow from natural gas in excess of capital investment was $410 million in 2013, an 11% decrease from 2012.
- Natural gas production in 2013 was approximately 529 million cubic feet per day (MMcf/d), down 11% from 2012. The decrease was driven by expected natural declines.
- Cenovus's average realized sales price for natural gas, including hedges, was $3.52 per thousand cubic feet (Mcf) for 2013 compared with $3.56 per Mcf in 2012.

## 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 $1.1 billion for the year, 11% lower than 2012. The decline was due to lower market crack spreads and increased costs associated with RINs, substantially offset by higher refined product output and an improved feedstock cost advantage attributable to processing record heavy crude volumes.
- The company invested $106 million in its refining operations during the year compared with $118 million in 2012. Operating cash flow in excess of capital invested was approximately $1 billion, net to Cenovus, in 2013.
- Crack spreads were impacted by higher crude oil pipeline takeaway capacity in the southern tier of the U.S., which alleviated inland congestion and increased West Texas Intermediate (WTI) crude oil prices, bringing them closer to Brent crude

prices. Higher refinery utilization, which increased supplies of transportation fuels across the U.S. Midwest, also impacted crack spreads.

- The cost of RINs increased almost five-fold from 2012 to $153 million, net to Cenovus, which negatively impacted 2013 gross refining margins. RIN costs have been trending lower since early in the fourth quarter of 2013 after the U.S. EPA proposed reducing the 2014 volume requirements for renewable blending.
- Cenovus's refineries processed an average of 442,000 bbls/d of crude oil in 2013, resulting in 463,000 bbls/d of refined product output. This was up about 7% from the previous year when product output was reduced by planned turnarounds at both refineries.
- The company's refineries processed an average of 222,000 bbls/d of heavy oil in 2013, the highest volume since the inception of the refining partnership in 2007, up 24,000 bbls/d compared with 2012.
- 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 2013 refining operating cash flow would have been $26 million lower than reported under FIFO compared with $111 million higher in 2012.

## Reserves and Contingent Resources

All of Cenovus's reserves and resources are evaluated each year by independent qualified reserves evaluators (IQREs).

- At year-end 2013, Cenovus had total proved reserves of almost 2.3 billion BOE, an increase of 5% compared with 2012.
- Proved bitumen reserves increased 8% in 2013 compared with 2012, to more than 1.8 billion bbls, while proved plus probable bitumen reserves grew 6% to approximately 2.5 billion bbls. This increase was primarily due to expansion of the development areas at Christina Lake and Foster Creek, plus an initial booking of probable reserves for the planned Grand Rapids project.
- Economic bitumen best estimate contingent resources increased to 9.8 billion bbls, up approximately 2% from 2012. Growth was more moderate than previous years as increases from stratigraphic well drilling and land acquisitions were offset by dispositions as well as slightly reduced recovery factors used by the company's IQREs in portions of two non-producing properties. For additional information on the company's contingent resources, see Oil and Gas Information in the Advisory.
- Proved light and medium oil reserves were unchanged, while proved heavy oil reserves decreased approximately 3% due to production outpacing additions and technical revisions to the resource base. Natural gas proved reserves declined about 9% compared with 2012 as Cenovus continued to focus capital on developing its oil assets. As expected, this has resulted in natural gas production outpacing reserves additions.
- Cenovus's 2013 proved finding and development (F&D) costs, excluding changes in future development costs, were $14.51/BOE, up from $9.04/BOE in 2012 due to lower reserves additions. The three-year average F&D costs were $9.05/BOE, excluding changes in future development costs.
- For our proved reserves, the IQREs have estimated our total future development costs to be $7.80 per BOE, or $6.20 per BOE on a de-escalated basis.

- Cenovus achieved production replacement of more than 200% in 2013.
- Cenovus continues to use its illustrative net asset value (NAV) as an important measure of long-term success. At the end of 2013, Cenovus's NAV was $35, a 12% decrease from year-end 2012. Despite solid growth in reserves and resources in 2013, the forecast of lower long-term commodity prices was the primary factor that resulted in this decline in NAV. Since the inception of the company in 2009, NAV has increased 25% primarily due to 72% total growth in reserves and resources.
- The overall proved reserves life index is approximately 24 years. The magnitude of the company's bitumen assets is significant with a bitumen proved reserves life index of 49 years, down 6% due to the company's increasing bitumen production. The conventional oil and NGLs proved reserves life is 11 years.

**Proved reserves reconciliation**

| (Before royalties) | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| **Start of 2013** | 1,717 | 184 | 115 | 955 |
| Extensions & improved recovery | 134 | 21 | 11 | 24 |
| Technical revisions | 32 | -12 | 6 | 76 |
| Economic factors | - | - | - | - |
| Acquisitions | - | - | - | - |
| Divestitures | - | - | -5 | - |
| Production[1] | -37 | -14 | -12 | -190 |
| **End of 2013** | 1,846 | 179 | 115 | 865 |
| % Change | 8 | -3 | - | -9 |
| Developed | 217 | 132 | 100 | 861 |
| Undeveloped | 1,629 | 47 | 15 | 4 |
| **Total proved** | 1,846 | 179 | 115 | 865 |
| **Total probable** | 683 | 140 | 50 | 300 |
| **Total proved plus probable** | 2,529 | 319 | 165 | 1,165 |

[1] Production used for the reserves reconciliation differs from reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production. See the Advisory – Oil and Gas Information for more information about royalty interest production.

| Proved reserves costs[1] | | | |
|---|---|---|---|
| (Before royalties) | **2013** | 2012 | 3 Year |
| **Capital Investment** ($ millions) | | | |
| Finding and Development | **3,026** | 3,013 | 8,214 |
| Finding, Development and Acquisitions | **3,058** | 3,127 | 8,429 |
| **Proved Reserves Additions**[2] (MMBOE) | | | |
| Finding and Development | **208** | 333 | 907 |
| Finding, Development and Acquisitions | **208** | 334 | 908 |
| **Proved Reserves Costs**[2] ($/BOE) | | | |
| Finding and Development[3] | **14.51** | 9.04 | 9.05 |
| Finding, Development and Acquisitions[4] | **14.67** | 9.36 | 9.28 |

[1] Finding and Development Cost calculations presented in the table do not include changes in future development costs. See the Advisory - Finding and Development Costs - for a full description of the methods used to calculate Finding and Development Costs which include the change in future development costs.
[2] Reserves Additions for Finding and Development are calculated by summing technical revisions, extensions and improved recovery, discoveries and economic factors. Reserves Additions for Finding, Development and Acquisitions are calculated by summing Reserves Additions for Finding and Development and additions from acquisitions. See the Advisory – Oil and Gas Information.
[3] Finding and Development Costs without changes in future development costs is equal to Finding and Development Capital Investment divided by Finding and Development Reserves Additions.
[4] Finding, Development and Acquisitions without changes in future development costs is equal to Finding, Development and Acquisitions Capital Investment divided by Finding, Development and Acquisitions Reserves Additions.

## Financial

### Dividend

The Cenovus Board of Directors approved a dividend increase of 10% for the first quarter of 2014, resulting in a dividend of $0.2662 per share, payable on March 31, 2014 to common shareholders of record as of March 14, 2014. Based on the February 12, 2014 closing share price on the Toronto Stock Exchange of $29.64, this represents an annualized yield of about 3.6%. Declaration of dividends is at the sole discretion of the Board. Cenovus's continued commitment to a meaningful dividend is an important aspect of the company's strategy to focus on increasing total shareholder return.

### Hedging strategy

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 expected 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 145 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 natural gas Cenovus produces. The company's financial hedging positions are determined after considering this natural hedge.

Cenovus's financial hedge positions at December 31, 2013 include:

- approximately 15% or 30,000 bbls/d of expected oil production hedged for 2014 at an average Brent price of US$102.04/bbl and an additional 10% or 20,000 bbls/d at an average Brent price of C$107.06/bbl
- a built-in hedge for natural gas production due to internal usage of about 145 MMcf/d of natural gas plus long-term fixed-price sales of 29 MMcf/d of natural gas
- approximately 15,900 bbls/d of heavy crude exposure hedged for 2014 at an average WCS differential to WTI of US$20.39/bbl.

**Financial Highlights**

- Operating cash flow was approximately $4.5 billion in 2013, comparable to 2012, due to higher crude oil volumes at Christina Lake and higher sales prices for crude. This was partially offset by lower realized risk management gains, increased operating costs and declines in natural gas production volumes.
- Cash flow in 2013 was $3.6 billion, or $4.76 per share diluted, unchanged from $3.6 billion, or $4.80 per share diluted, in 2012.
- Operating earnings were $1.2 billion, or $1.55 per share diluted, up 35% from 2012. The increase was due to the same factors affecting operating cash flow as well as a decline of $111 million in deferred income tax expense and no goodwill impairment in the year compared with an impairment of $393 million in 2012. Higher operating earnings were partially offset by increased depreciation, depletion and amortization expense.
- Cenovus's net earnings for the year were $662 million compared with $995 million in 2012. The decrease was primarily the result of unrealized after-tax risk management losses of $310 million compared with gains of $43 million a year earlier, as well as realized after-tax foreign exchange losses of $146 million related to a decision by Cenovus's partner ConocoPhillips to pay the remaining principal of a receivable connected to the oil sands joint operation and after-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million the previous year.
- Cenovus had a realized after-tax hedging gain of $93 million in 2013. The company received an average realized price, including hedging, of $68.10/bbl for its oil in 2013 compared with $67.18/bbl in 2012. The average realized price for natural gas in the year, including hedging, was $3.52/Mcf compared with $3.56/Mcf in 2012.
- Cenovus recorded income tax expense of $432 million for 2013, giving the company an effective tax rate of 39.5% compared with an effective rate of 44% in 2012, primarily due to a non-deductible goodwill impairment charge of $393 million in 2012 and U.S. withholding tax on dividends of $68 million, offset by non-deductible foreign exchange losses in 2013.
- Capital investment for the year was $3.3 billion, a 3% decrease from $3.4 billion in 2012 as a result of lower spending at the company's Pelican Lake operation as well as reduced investment in Saskatchewan after the sale of the company's Shaunavon tight oil asset.
- General and administrative (G&A) expenses were $349 million in 2013, comparable with $350 million in the previous year. Excluding the impact of long-term incentives, costs increased due to higher rent and staffing expenses.
- Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) ratio of between 1.0 and 2.0 times. At

December 31, 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 December 31)<br>($ millions, except per share amounts) | **2013 Q4** | 2012 Q4 | **2013 Full Year** | 2012 Full Year |
|---|---|---|---|---|
| **Net earnings** | -58 | -117 | **662** | 995 |
| Add back (deduct): | | | | |
| Unrealized risk management (gains) losses, after-tax | 163 | (87) | **310** | (43) |
| Non-operating unrealized foreign exchange (gains) losses, after-tax | (39) | 16 | **52** | (84) |
| Realized foreign exchange loss on Partnership Contribution Receivable, after-tax | 146 | - | **146** | - |
| Divestiture (gains) losses, after-tax | - | - | **1** | - |
| **Operating earnings** | 212 | -188 | **1,171** | 868 |
| Per share diluted | 0.28 | (0.25) | **1.55** | 1.14 |

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

## Oil sands project schedule

| Project phase | Regulatory status | First production target | Expected total production capacity (bbls/d) gross |
|---|---|---|---|
| **Foster Creek[1] A – E** | | | 120,000 |
| F, G, H | Approved | Q3-2014F[2] | 125,000[3,4] |
| J | Submitted Q1-2013 | 2019F | 50,000 |
| Additional optimization | | | 15,000 |
| **Total capacity** | | | 310,000 |
| **Christina Lake[1] A – E** | | | 138,000 |
| Optimization (phases C,D,E) | Approved | 2015F | 22,000 |
| F, G | Approved | 2016F[5] | 100,000 |
| 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[6]** | 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] Represents first production target for phase F. Phase G first production expected in 2015 and phase H in 2016.
[3] Each of phases F, G, H are expected to ramp up to 30,000 bbls/d in 12 to 18 months from first production. Optimization is expected to add an additional 35,000 bbls/d between 2016 and 2019.
[4] Includes 5,000 bbls/d gross submitted to the regulator in Q1 2013.
[5] Represents first production target for phase F. Phase G first production expected in 2017.
[6] Projected potential total capacity of more than 300,000 bbls/d.

## Conference Call Today

**9 a.m. Mountain Time (11 a.m. Eastern Time)**

Cenovus will host a conference call today, February 13, 2014, starting at 9 a.m. MT (11 a.m. ET). To participate, please dial 1-888-231-8191 (toll-free in North America) or 1-647-427-7450 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 12 p.m. MT on February 13, 2014, until 10 p.m. MT on February 20, 2014, by dialing 1-855-859-2056 or 1-416-849-0833 and entering conference passcode 19216840. A live audio webcast of the conference call will also be available via cenovus.com. The webcast will be archived for approximately 90 days.

## 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 news release 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. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.
- 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, the effect of changes in statutory income tax rates, and the after-tax realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable. 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.
- 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 news release 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 AND GAS INFORMATION

The estimates of reserves and resources data and related information were prepared effective December 31, 2013 by independent qualified reserves evaluators ("IQREs"), based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. Estimates are presented using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2014 price forecast. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalties volumes presented in the reserves reconciliation (i) do not include reserves associated with this production and (ii) the production differs from other publicly reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production.

### Resources Information

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 percent probability that the actual quantities recovered will equal or exceed the estimate.

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. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

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. The Canadian Oil and Gas Evaluation Handbook 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 economic 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 four regions is included in our Annual Information Form.

**Barrels of Oil Equivalent** Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one bbl. 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.

**Finding and Development Costs** Finding and development costs disclosed in this news release and used for calculating our recycle ratio do not include the change in estimated future development costs. Cenovus uses finding and development costs without changes in estimated future development costs as an indicator of relative performance to be consistent with the methodology accepted within the oil and gas industry.

Finding and development costs for *proved reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $32.97/BOE for the year ended December 31, 2013, $25.48/BOE for the year ended December 31, 2012 and averaged $22.57/BOE for the three years ended December 31, 2013. Finding and development costs for *proved plus probable reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $40.85/BOE for the year ended December 31, 2013, $20.04/BOE for the year ended December 31, 2012 and averaged $17.56/BOE for the three years ended December 31, 2013. These finding and development costs were calculated by dividing the sum of exploration costs, development costs and changes in future development costs in the particular period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period and the change during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

**Net Asset Value** With respect to the particular year being valued, the net asset value (NAV) disclosed herein is based on the number of issued and outstanding Cenovus shares as at December 31 as reported in our Annual Information Form and Form 40-F, plus the total dilutive effect of Cenovus shares related to stock option programs or other contracts as disclosed in the "Per Share Amounts" note to our annual Consolidated Financial Statements. We calculate NAV as an average of (i) our average trading price for the month of December, (ii) an average of net asset values published by external analysts in December following the announcement of our budget forecast, and (iii) an average of two net asset values based primarily on discounted cash flows of independently evaluated reserves, resources and refining data and using internal corporate costs, with one based on constant prices and costs and one based on forecast prices and costs.

## 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", "goal", "proposed", "scheduled", "potential", "may", "projected", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projections contained in our 2014 guidance, projected net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, estimated finding and development costs, expected reserves and contingent resources estimates, estimated proved reserves life index, broadening market access, improving cost structures, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

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

2014 guidance, updated February 13, 2014, available at cenovus.com, is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of C$3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00; WTI of US$100.00-US$106.00/bbl; Western Canada Select of C$81.00-C$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of C$3.70-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 million.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our 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, including sufficient crude-by-rail or other alternate transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our 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 Annual Information Form/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 sec.gov and our website at cenovus.com.

TM denotes a trademark of Cenovus Energy Inc.

### Cenovus Energy Inc.

Cenovus Energy Inc. is a Canadian integrated oil company. It is committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. Operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface, and established natural gas and oil production in Alberta and Saskatchewan. The company also has 50% ownership in two U.S. refineries. Cenovus shares trade under the symbol CVE, and are listed on the Toronto and New York stock exchanges. Its enterprise value is approximately $27 billion. For more information, visit cenovus.com.

Find Cenovus on Facebook, Twitter, Linkedin and YouTube.

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# CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

**For the Period Ended December 31,**
**($ millions, except per share amounts)**

| | Notes | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|---|
| | | | (Note 3) | | (Note 3) |
| **Revenues** | 1 | | | | |
| Gross Sales | | **4,827** | 3,802 | **18,993** | 17,229 |
| Less: Royalties | | **80** | 78 | **336** | 387 |
| | | **4,747** | 3,724 | **18,657** | 16,842 |
| **Expenses** | 1 | | | | |
| Purchased Product | | **2,776** | 1,888 | **10,399** | 9,223 |
| Transportation and Blending | | **592** | 475 | **2,074** | 1,798 |
| Operating | | **474** | 478 | **1,798** | 1,667 |
| Production and Mineral Taxes | | **5** | 9 | **35** | 37 |
| (Gain) Loss on Risk Management | 21 | **142** | (209) | **293** | (393) |
| Depreciation, Depletion and Amortization | 11,13 | **468** | 409 | **1,833** | 1,585 |
| Goodwill Impairment | 14 | **-** | 393 | **-** | 393 |
| Exploration Expense | | **5** | - | **114** | 68 |
| General and Administrative | | **81** | 97 | **349** | 350 |
| Finance Costs | 4 | **122** | 111 | **529** | 455 |
| Interest Income | 5 | **(23)** | (25) | **(96)** | (109) |
| Foreign Exchange (Gain) Loss, Net | 6 | **115** | 22 | **208** | (20) |
| Research Costs | | **10** | 3 | **24** | 15 |
| (Gain) Loss on Divestiture of Assets | | **-** | - | **1** | - |
| Other (Income) Loss, Net | | **2** | (1) | **2** | (5) |
| **Earnings (Loss) Before Income Tax** | | **(22)** | 74 | **1,094** | 1,778 |
| Income Tax Expense | 7 | **36** | 191 | **432** | 783 |
| **Net Earnings (Loss)** | | **(58)** | (117) | **662** | 995 |
| **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 | | **(1)** | (1) | **14** | (4) |
| *Items That May be Subsequently Reclassified to Profit or Loss:* | | | | | |
| Change in Value of Available for Sale Financial Assets | | **2** | - | **10** | - |
| Foreign Currency Translation Adjustment | | **59** | 12 | **117** | (24) |
| **Total Other Comprehensive Income (Loss), Net of Tax** | | **60** | 11 | **141** | (28) |
| **Comprehensive Income (Loss)** | | **2** | (106) | **803** | 967 |
| **Net Earnings (Loss) Per Common Share** | 8 | | | | |
| Basic | | **$(0.08)** | $(0.15) | **$0.88** | $1.32 |
| Diluted | | **$(0.08)** | $(0.15) | **$0.87** | $1.31 |

*See accompanying Notes to Consolidated Financial Statements (unaudited).*

# CONSOLIDATED BALANCE SHEETS (unaudited)

**As at**
**($ millions)**

| | Notes | **December 31, 2013** | December 31, 2012 (Note 3) | January 1, 2012 (Note 3) |
|---|---|---|---|---|
| **Assets** | | | | |
| **Current Assets** | | | | |
| Cash and Cash Equivalents | | **2,452** | 1,160 | 495 |
| Accounts Receivable and Accrued Revenues | | **1,874** | 1,464 | 1,405 |
| Income Tax Receivable | | **15** | - | - |
| Current Portion of Partnership Contribution Receivable | 9 | **-** | 384 | 372 |
| Inventories | 10 | **1,259** | 1,288 | 1,291 |
| Risk Management | 21 | **10** | 283 | 232 |
| Assets Held for Sale | 11 | **-** | - | 116 |
| **Current Assets** | | **5,610** | 4,579 | 3,911 |
| Exploration and Evaluation Assets | 1,12 | **1,473** | 1,285 | 880 |
| Property, Plant and Equipment, Net | 1,13 | **17,334** | 16,152 | 14,324 |
| Partnership Contribution Receivable | 9 | **-** | 1,398 | 1,822 |
| Risk Management | 21 | **-** | 5 | 52 |
| Income Tax Receivable | | **-** | - | 29 |
| Other Assets | | **68** | 58 | 44 |
| Goodwill | 1,14 | **739** | 739 | 1,132 |
| **Total Assets** | | **25,224** | 24,216 | 22,194 |
| | | | | |
| **Liabilities and Shareholders' Equity** | | | | |
| **Current Liabilities** | | | | |
| Accounts Payable and Accrued Liabilities | | **2,937** | 2,650 | 2,579 |
| Income Tax Payable | | **268** | 217 | 329 |
| Current Portion of Partnership Contribution Payable | | **438** | 386 | 372 |
| Risk Management | 21 | **136** | 17 | 54 |
| Liabilities Related to Assets Held for Sale | 11 | **-** | - | 54 |
| **Current Liabilities** | | **3,779** | 3,270 | 3,388 |
| Long-Term Debt | 15 | **4,997** | 4,679 | 3,527 |
| Partnership Contribution Payable | | **1,087** | 1,426 | 1,853 |
| Risk Management | 21 | **3** | 1 | 14 |
| Decommissioning Liabilities | 16 | **2,370** | 2,315 | 1,777 |
| Other Liabilities | | **180** | 183 | 158 |
| Deferred Income Taxes | | **2,862** | 2,560 | 2,093 |
| **Total Liabilities** | | **15,278** | 14,434 | 12,810 |
| Shareholders' Equity | | **9,946** | 9,782 | 9,384 |
| **Total Liabilities and Shareholders' Equity** | | **25,224** | 24,216 | 22,194 |

*See accompanying Notes to Consolidated Financial Statements (unaudited).*

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

**($ millions)**

| | Share Capital (Note 17) | Paid in Surplus | Retained Earnings | AOCI [1] (Note 18) | Total |
|---|---|---|---|---|---|
| **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 | - | - | 995 | - | 995 |
| Other Comprehensive Income (Loss) | - | - | - | (28) | (28) |
| Total Comprehensive Income (Loss) | - | - | 995 | (28) | 967 |
| Common Shares Issued Under Option Plans | 49 | - | - | - | 49 |
| Stock-Based Compensation Expense | - | 47 | - | - | 47 |
| Dividends on Common Shares | - | - | (665) | - | (665) |
| **Balance as at December 31, 2012** | 3,829 | 4,154 | 1,730 | 69 | 9,782 |
| Net Earnings | - | - | 662 | - | 662 |
| Other Comprehensive Income (Loss) | - | - | - | 141 | 141 |
| Total Comprehensive Income (Loss) | - | - | 662 | 141 | 803 |
| Common Shares Issued Under Option Plans | 31 | - | - | - | 31 |
| Common Shares Cancelled | (3) | 3 | - | - | - |
| Stock-Based Compensation Expense | - | 62 | - | - | 62 |
| Dividends on Common Shares | - | - | (732) | - | (732) |
| **Balance as at December 31, 2013** | **3,857** | **4,219** | **1,660** | **210** | **9,946** |

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

*See accompanying Notes to Consolidated Financial Statements (unaudited).*

# CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

**For the Period Ended December 31,**
**($ millions)**

| | Notes | Three Months Ended 2013 | Three Months Ended 2012 | Twelve Months Ended 2013 | Twelve Months Ended 2012 |
|---|---|---|---|---|---|
| | | | (Note 3) | | (Note 3) |
| **Operating Activities** | | | | | |
| Net Earnings (Loss) | | **(58)** | (117) | **662** | 995 |
| Depreciation, Depletion and Amortization | | **468** | 409 | **1,833** | 1,585 |
| Goodwill Impairment | 14 | **-** | 393 | **-** | 393 |
| Exploration Expense | | **5** | - | **50** | 68 |
| Deferred Income Taxes | 7 | **33** | 66 | **244** | 474 |
| Unrealized (Gain) Loss on Risk Management | 21 | **219** | (117) | **415** | (57) |
| Unrealized Foreign Exchange (Gain) Loss | 6 | **(46)** | 12 | **40** | (70) |
| Unwinding of Discount on Decommissioning Liabilities | 4,16 | **25** | 22 | **97** | 86 |
| Other | | **189** | 29 | **268** | 169 |
| | | **835** | 697 | **3,609** | 3,643 |
| Net Change in Other Assets and Liabilities | | **(30)** | (42) | **(120)** | (113) |
| Net Change in Non-Cash Working Capital | | **171** | 103 | **50** | (110) |
| **Cash From Operating Activities** | | **976** | 758 | **3,539** | 3,420 |
| **Investing Activities** | | | | | |
| Capital Expenditures – Exploration and Evaluation Assets | 12 | **(76)** | (203) | **(331)** | (654) |
| Capital Expenditures – Property, Plant and Equipment | 13 | **(824)** | (812) | **(2,938)** | (2,795) |
| Proceeds From Divestiture of Assets | | **16** | 11 | **258** | 76 |
| Net Change in Investments and Other | 9 | **1,489** | (3) | **1,486** | (13) |
| Net Change in Non-Cash Working Capital | | **33** | 32 | **6** | 50 |
| **Cash From (Used in) Investing Activities** | | **638** | (975) | **(1,519)** | (3,336) |
| **Net Cash Provided (Used) Before Financing Activities** | | **1,614** | (217) | **2,020** | 84 |
| **Financing Activities** | | | | | |
| Net Issuance (Repayment) of Short-Term Borrowings | | **(9)** | - | **(8)** | 3 |
| Issuance of U.S. Unsecured Notes | 15 | **-** | - | **814** | 1,219 |
| Repayment of U.S. Unsecured Notes | 15 | **-** | - | **(825)** | - |
| Proceeds on Issuance of Common Shares | | **5** | 2 | **28** | 37 |
| Dividends Paid on Common Shares | 8 | **(183)** | (167) | **(732)** | (665) |
| Other | | **-** | (3) | **(3)** | (2) |
| **Cash From (Used in) Financing Activities** | | **(187)** | (168) | **(726)** | 592 |
| **Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency** | | **1** | 2 | **(2)** | (11) |
| **Increase (Decrease) in Cash and Cash Equivalents** | | **1,428** | (383) | **1,292** | 665 |
| **Cash and Cash Equivalents, Beginning of Period** | | **1,024** | 1,543 | **1,160** | 495 |
| **Cash and Cash Equivalents, End of Period** | | **2,452** | 1,160 | **2,452** | 1,160 |

*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 preparation for these Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow. The Company's reportable segments are:

- **Oil Sands,** which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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 heavy oil assets at Pelican Lake. This segment also includes 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, research costs 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 operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation. As a result, for the three months and year ended December 31, 2012, segment income of $61 million and $275 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted for the year ended December 31, 2013.

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

### A) Results of Operations – Segment and Operational Information

| | Oil Sands | | Conventional | | Refining and Marketing | |
|---|---|---|---|---|---|---|
| For the three months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **1,075** | 895 | **692** | 689 | **3,223** | 2,336 |
| Less: Royalties | **38** | 34 | **42** | 44 | **-** | - |
| | **1,037** | 861 | **650** | 645 | **3,223** | 2,336 |
| **Expenses** | | | | | | |
| Purchased Product | **-** | - | **-** | - | **2,939** | 2,006 |
| Transportation and Blending | **517** | 408 | **75** | 67 | **-** | - |
| Operating | **153** | 113 | **179** | 168 | **143** | 197 |
| Production and Mineral Taxes | **-** | - | **5** | 9 | **-** | - |
| (Gain) Loss on Risk Management | **(31)** | (38) | **(36)** | (64) | **(10)** | 10 |
| **Operating Cash Flow** | **398** | 378 | **427** | 465 | **151** | 123 |
| Depreciation, Depletion and Amortization | **133** | 93 | **279** | 262 | **36** | 37 |
| Goodwill Impairment | **-** | - | **-** | 393 | **-** | - |
| Exploration Expense | **-** | - | **5** | - | **-** | - |
| **Segment Income (Loss)** | **265** | 285 | **143** | (190) | **115** | 86 |

| | Corporate and Eliminations | | Consolidated | |
|---|---|---|---|---|
| For the three months ended December 31, | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | |
| Gross Sales | **(163)** | (118) | **4,827** | 3,802 |
| Less: Royalties | **-** | - | **80** | 78 |
| | **(163)** | (118) | **4,747** | 3,724 |
| **Expenses** | | | | |
| Purchased Product | **(163)** | (118) | **2,776** | 1,888 |
| Transportation and Blending | **-** | - | **592** | 475 |
| Operating | **(1)** | - | **474** | 478 |
| Production and Mineral Taxes | **-** | - | **5** | 9 |
| (Gain) Loss on Risk Management | **219** | (117) | **142** | (209) |
| | **(218)** | 117 | **758** | 1,083 |
| Depreciation, Depletion and Amortization | **20** | 17 | **468** | 409 |
| Goodwill Impairment | **-** | - | **-** | 393 |
| Exploration Expense | **-** | - | **5** | - |
| **Segment Income (Loss)** | **(238)** | 100 | **285** | 281 |
| General and Administrative | **81** | 97 | **81** | 97 |
| Finance Costs | **122** | 111 | **122** | 111 |
| Interest Income | **(23)** | (25) | **(23)** | (25) |
| Foreign Exchange (Gain) Loss, Net | **115** | 22 | **115** | 22 |
| Research Costs | **10** | 3 | **10** | 3 |
| (Gain) Loss on Divestiture of Assets | **-** | - | **-** | - |
| Other (Income) Loss, Net | **2** | (1) | **2** | (1) |
| | **307** | 207 | **307** | 207 |
| **Earnings (Loss) Before Income Tax** | | | **(22)** | 74 |
| Income Tax Expense | | | **36** | 191 |
| **Net Earnings (Loss)** | | | **(58)** | (117) |

## B) Financial Results by Upstream Product

| | Crude Oil (1) | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the three months ended December 31, | 2013 | 2012 | 2013 | 2012 | 2013 | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | 1,053 | 876 | 544 | 539 | 1,597 | 1,415 |
| Less: Royalties | 38 | 34 | 40 | 42 | 78 | 76 |
| | 1,015 | 842 | 504 | 497 | 1,519 | 1,339 |
| **Expenses** | | | | | | |
| Transportation and Blending | 517 | 407 | 70 | 63 | 587 | 470 |
| Operating | 145 | 106 | 126 | 107 | 271 | 213 |
| Production and Mineral Taxes | - | - | 4 | 10 | 4 | 10 |
| (Gain) Loss on Risk Management | (30) | (35) | (20) | (21) | (50) | (56) |
| **Operating Cash Flow** | 383 | 364 | 324 | 338 | 707 | 702 |

*(1) Includes NGLs.*

| | Natural Gas | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the three months ended December 31, | 2013 | 2012 | 2013 | 2012 | 2013 | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | 14 | 15 | 145 | 146 | 159 | 161 |
| Less: Royalties | - | - | 2 | 2 | 2 | 2 |
| | 14 | 15 | 143 | 144 | 157 | 159 |
| **Expenses** | | | | | | |
| Transportation and Blending | - | 1 | 5 | 4 | 5 | 5 |
| Operating | 6 | 7 | 52 | 60 | 58 | 67 |
| Production and Mineral Taxes | - | - | 1 | (1) | 1 | (1) |
| (Gain) Loss on Risk Management | (1) | (3) | (16) | (43) | (17) | (46) |
| **Operating Cash Flow** | 9 | 10 | 101 | 124 | 110 | 134 |

| | Other | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the three months ended December 31, | 2013 | 2012 | 2013 | 2012 | 2013 | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | 8 | 4 | 3 | 4 | 11 | 8 |
| Less: Royalties | - | - | - | - | - | - |
| | 8 | 4 | 3 | 4 | 11 | 8 |
| **Expenses** | | | | | | |
| Transportation and Blending | - | - | - | - | - | - |
| Operating | 2 | - | 1 | 1 | 3 | 1 |
| Production and Mineral Taxes | - | - | - | - | - | - |
| (Gain) Loss on Risk Management | - | - | - | - | - | - |
| **Operating Cash Flow** | 6 | 4 | 2 | 3 | 8 | 7 |

| | Total Upstream | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the three months ended December 31, | 2013 | 2012 | 2013 | 2012 | 2013 | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | 1,075 | 895 | 692 | 689 | 1,767 | 1,584 |
| Less: Royalties | 38 | 34 | 42 | 44 | 80 | 78 |
| | 1,037 | 861 | 650 | 645 | 1,687 | 1,506 |
| **Expenses** | | | | | | |
| Transportation and Blending | 517 | 408 | 75 | 67 | 592 | 475 |
| Operating | 153 | 113 | 179 | 168 | 332 | 281 |
| Production and Mineral Taxes | - | - | 5 | 9 | 5 | 9 |
| (Gain) Loss on Risk Management | (31) | (38) | (36) | (64) | (67) | (102) |
| **Operating Cash Flow** | 398 | 378 | 427 | 465 | 825 | 843 |

### C) Geographic Information

| | Canada | | United States | | Consolidated | |
|---|---|---|---|---|---|---|
| For the three months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **2,270** | 2,010 | **2,557** | 1,792 | **4,827** | 3,802 |
| Less: Royalties | **80** | 78 | **-** | - | **80** | 78 |
| | **2,190** | 1,932 | **2,557** | 1,792 | **4,747** | 3,724 |
| **Expenses** | | | | | | |
| Purchased Product | **497** | 418 | **2,279** | 1,470 | **2,776** | 1,888 |
| Transportation and Blending | **592** | 475 | **-** | - | **592** | 475 |
| Operating | **335** | 286 | **139** | 192 | **474** | 478 |
| Production and Mineral Taxes | **5** | 9 | **-** | - | **5** | 9 |
| (Gain) Loss on Risk Management | **153** | (216) | **(11)** | 7 | **142** | (209) |
| | **608** | 960 | **150** | 123 | **758** | 1,083 |
| Depreciation, Depletion and Amortization | **432** | 372 | **36** | 37 | **468** | 409 |
| Goodwill Impairment | **-** | 393 | **-** | - | **-** | 393 |
| Exploration Expense | **5** | - | **-** | - | **5** | - |
| **Segment Income** | **171** | 195 | **114** | 86 | **285** | 281 |

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

| For the twelve months ended December 31, | Oil Sands 2013 | Oil Sands 2012 | Conventional 2013 | Conventional 2012 | Refining and Marketing 2013 | Refining and Marketing 2012 |
|---|---|---|---|---|---|---|
| **Revenues** | | | | | | |
| Gross Sales | **3,912** | 3,356 | **2,980** | 2,800 | **12,706** | 11,356 |
| Less: Royalties | **132** | 186 | **204** | 201 | **-** | - |
| | **3,780** | 3,170 | **2,776** | 2,599 | **12,706** | 11,356 |
| **Expenses** | | | | | | |
| Purchased Product | **-** | - | **-** | - | **11,004** | 9,506 |
| Transportation and Blending | **1,749** | 1,501 | **325** | 297 | **-** | - |
| Operating | **555** | 426 | **708** | 662 | **540** | 581 |
| Production and Mineral Taxes | **-** | - | **35** | 37 | **-** | - |
| (Gain) Loss on Risk Management | **(37)** | (64) | **(104)** | (268) | **19** | (4) |
| **Operating Cash Flow** | **1,513** | 1,307 | **1,812** | 1,871 | **1,143** | 1,273 |
| Depreciation, Depletion and Amortization | **446** | 339 | **1,170** | 1,048 | **138** | 146 |
| Goodwill Impairment | **-** | - | **-** | 393 | **-** | - |
| Exploration Expense | **-** | - | **114** | 68 | **-** | - |
| **Segment Income (Loss)** | **1,067** | 968 | **528** | 362 | **1,005** | 1,127 |

| For the twelve months ended December 31, | Corporate and Eliminations 2013 | Corporate and Eliminations 2012 | Consolidated 2013 | Consolidated 2012 |
|---|---|---|---|---|
| **Revenues** | | | | |
| Gross Sales | **(605)** | (283) | **18,993** | 17,229 |
| Less: Royalties | **-** | - | **336** | 387 |
| | **(605)** | (283) | **18,657** | 16,842 |
| **Expenses** | | | | |
| Purchased Product | **(605)** | (283) | **10,399** | 9,223 |
| Transportation and Blending | **-** | - | **2,074** | 1,798 |
| Operating | **(5)** | (2) | **1,798** | 1,667 |
| Production and Mineral Taxes | **-** | - | **35** | 37 |
| (Gain) Loss on Risk Management | **415** | (57) | **293** | (393) |
| | **(410)** | 59 | **4,058** | 4,510 |
| Depreciation, Depletion and Amortization | **79** | 52 | **1,833** | 1,585 |
| Goodwill Impairment | **-** | - | **-** | 393 |
| Exploration Expense | **-** | - | **114** | 68 |
| **Segment Income (Loss)** | **(489)** | 7 | **2,111** | 2,464 |
| General and Administrative | **349** | 350 | **349** | 350 |
| Finance Costs | **529** | 455 | **529** | 455 |
| Interest Income | **(96)** | (109) | **(96)** | (109) |
| Foreign Exchange (Gain) Loss, Net | **208** | (20) | **208** | (20) |
| Research Costs | **24** | 15 | **24** | 15 |
| (Gain) Loss on Divestiture of Assets | **1** | - | **1** | - |
| Other (Income) Loss, Net | **2** | (5) | **2** | (5) |
| | **1,017** | 686 | **1,017** | 686 |
| **Earnings Before Income Tax** | | | **1,094** | 1,778 |
| Income Tax Expense | | | **432** | 783 |
| **Net Earnings** | | | **662** | 995 |

## E) Financial Results by Upstream Product

| | Crude Oil [1] | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the twelve months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **3,850** | 3,307 | **2,373** | 2,289 | **6,223** | 5,596 |
| Less: Royalties | **131** | 186 | **196** | 195 | **327** | 381 |
| | **3,719** | 3,121 | **2,177** | 2,094 | **5,896** | 5,215 |
| **Expenses** | | | | | | |
| Transportation and Blending | **1,748** | 1,499 | **305** | 278 | **2,053** | 1,777 |
| Operating | **531** | 401 | **495** | 441 | **1,026** | 842 |
| Production and Mineral Taxes | **-** | - | **32** | 34 | **32** | 34 |
| (Gain) Loss on Risk Management | **(33)** | (46) | **(43)** | (39) | **(76)** | (85) |
| **Operating Cash Flow** | **1,473** | 1,267 | **1,388** | 1,380 | **2,861** | 2,647 |

*(1) Includes NGLs.*

| | Natural Gas | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the twelve months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **38** | 38 | **594** | 498 | **632** | 536 |
| Less: Royalties | **1** | - | **8** | 6 | **9** | 6 |
| | **37** | 38 | **586** | 492 | **623** | 530 |
| **Expenses** | | | | | | |
| Transportation and Blending | **1** | 2 | **20** | 19 | **21** | 21 |
| Operating | **18** | 23 | **209** | 217 | **227** | 240 |
| Production and Mineral Taxes | **-** | - | **3** | 3 | **3** | 3 |
| (Gain) Loss on Risk Management | **(4)** | (18) | **(61)** | (229) | **(65)** | (247) |
| **Operating Cash Flow** | **22** | 31 | **415** | 482 | **437** | 513 |

| | Other | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the twelve months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **24** | 11 | **13** | 13 | **37** | 24 |
| Less: Royalties | **-** | - | **-** | - | **-** | - |
| | **24** | 11 | **13** | 13 | **37** | 24 |
| **Expenses** | | | | | | |
| Transportation and Blending | **-** | - | **-** | - | **-** | - |
| Operating | **6** | 2 | **4** | 4 | **10** | 6 |
| Production and Mineral Taxes | **-** | - | **-** | - | **-** | - |
| (Gain) Loss on Risk Management | **-** | - | **-** | - | **-** | - |
| **Operating Cash Flow** | **18** | 9 | **9** | 9 | **27** | 18 |

| | Total Upstream | | | | | |
|---|---|---|---|---|---|---|
| | Oil Sands | | Conventional | | Total | |
| For the twelve months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **3,912** | 3,356 | **2,980** | 2,800 | **6,892** | 6,156 |
| Less: Royalties | **132** | 186 | **204** | 201 | **336** | 387 |
| | **3,780** | 3,170 | **2,776** | 2,599 | **6,556** | 5,769 |
| **Expenses** | | | | | | |
| Transportation and Blending | **1,749** | 1,501 | **325** | 297 | **2,074** | 1,798 |
| Operating | **555** | 426 | **708** | 662 | **1,263** | 1,088 |
| Production and Mineral Taxes | **-** | - | **35** | 37 | **35** | 37 |
| (Gain) Loss on Risk Management | **(37)** | (64) | **(104)** | (268) | **(141)** | (332) |
| **Operating Cash Flow** | **1,513** | 1,307 | **1,812** | 1,871 | **3,325** | 3,178 |

## F) Geographic Information

| | Canada | | United States | | Consolidated | |
|---|---|---|---|---|---|---|
| For the twelve months ended December 31, | **2013** | 2012 | **2013** | 2012 | **2013** | 2012 |
| **Revenues** | | | | | | |
| Gross Sales | **8,943** | 8,069 | **10,050** | 9,160 | **18,993** | 17,229 |
| Less: Royalties | **336** | 387 | **-** | - | **336** | 387 |
| | **8,607** | 7,682 | **10,050** | 9,160 | **18,657** | 16,842 |
| **Expenses** | | | | | | |
| Purchased Product | **2,022** | 1,884 | **8,377** | 7,339 | **10,399** | 9,223 |
| Transportation and Blending | **2,074** | 1,798 | **-** | - | **2,074** | 1,798 |
| Operating | **1,276** | 1,108 | **522** | 559 | **1,798** | 1,667 |
| Production and Mineral Taxes | **35** | 37 | **-** | - | **35** | 37 |
| (Gain) Loss on Risk Management | **275** | (385) | **18** | (8) | **293** | (393) |
| | **2,925** | 3,240 | **1,133** | 1,270 | **4,058** | 4,510 |
| Depreciation, Depletion and Amortization | **1,695** | 1,439 | **138** | 146 | **1,833** | 1,585 |
| Goodwill Impairment | **-** | 393 | **-** | - | **-** | 393 |
| Exploration Expense | **114** | 68 | **-** | - | **114** | 68 |
| **Segment Income** | **1,116** | 1,340 | **995** | 1,124 | **2,111** | 2,464 |

## 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 December 31, 2013 was $355 million and $154 million, respectively (three months ended December 31, 2012 – $328 million and $121 million). Cenovus's share of operating cash flow from FCCL and WRB for the year ended December 31, 2013 was $1,383 million and $1,144 million, respectively (year ended December 31, 2012 – $1,188 million and $1,274 million).

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

### *By Segment*

| | E&E [1] | | PP&E [2] | |
|---|---|---|---|---|
| As at | **December 31, 2013** | December 31, 2012 | **December 31, 2013** | December 31, 2012 |
| Oil Sands | **1,313** | 1,064 | **7,401** | 6,041 |
| Conventional | **160** | 221 | **6,291** | 6,652 |
| Refining and Marketing | **-** | - | **3,269** | 3,088 |
| Corporate and Eliminations | **-** | - | **373** | 371 |
| **Consolidated** | **1,473** | 1,285 | **17,334** | 16,152 |

| | Goodwill | | Total Assets | |
|---|---|---|---|---|
| As at | **December 31, 2013** | December 31, 2012 | **December 31, 2013** | December 31, 2012 |
| Oil Sands | **242** | 242 | **9,549** | 9,658 |
| Conventional | **497** | 497 | **7,235** | 7,618 |
| Refining and Marketing | **-** | - | **5,491** | 5,018 |
| Corporate and Eliminations | **-** | - | **2,949** | 1,922 |
| **Consolidated** | **739** | 739 | **25,224** | 24,216 |

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

### *By Geographic Region*

| | E&E | | PP&E | |
|---|---|---|---|---|
| As at | **December 31, 2013** | December 31, 2012 | **December 31, 2013** | December 31, 2012 |
| Canada | **1,473** | 1,285 | **14,066** | 13,065 |
| United States | **-** | - | **3,268** | 3,087 |
| **Consolidated** | **1,473** | 1,285 | **17,334** | 16,152 |

| | Goodwill | | Total Assets | |
|---|---|---|---|---|
| As at | **December 31, 2013** | December 31, 2012 | **December 31, 2013** | December 31, 2012 |
| Canada | **739** | 739 | **20,548** | 19,744 |
| United States | **-** | - | **4,676** | 4,472 |
| **Consolidated** | **739** | 739 | **25,224** | 24,216 |

## I) Capital Expenditures [1]

| | Three Months Ended | | Twelve Months Ended | |
|---|---|---|---|---|
| For the period ended December 31, | **2013** | 2012 | **2013** | 2012 |
| **Capital** | | | | |
| Oil Sands | **502** | 458 | **1,883** | 1,693 |
| Conventional | **331** | 404 | **1,191** | 1,366 |
| Refining and Marketing | **37** | 58 | **107** | 118 |
| Corporate | **28** | 58 | **81** | 191 |
| | **898** | 978 | **3,262** | 3,368 |
| **Acquisition Capital** | | | | |
| Oil Sands [2] | **26** | 67 | **27** | 69 |
| Conventional | **1** | 3 | **5** | 45 |
| | **925** | 1,048 | **3,294** | 3,482 |

*(1) Includes expenditures on PP&E and E&E.*
*(2) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.*

## 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 February 12, 2014.

## 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 and 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 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 partnership. 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.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through other comprehensive income ("OCI"). 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 requirement had no impact on the Consolidated Financial Statements.

The effect on the Consolidated Balance Sheets of IAS 19R 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 of IAS 19R was as follows:

| | Three Months Ended December 31, 2012 | Twelve Months Ended December 31, 2012 |
|---|---|---|
| Decrease in General and Administrative Expense | 1 | 2 |
| Increase in Net Earnings for the Period | 1 | 2 |
| Remeasurement of Defined Benefit and OPEB Liabilities | (1) | (4) |
| (Decrease) in Comprehensive Income for the Period | - | (2) |

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 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 (1) | 4 | 1 |
| Benefits Paid | (2) | - |
| Plan Participant Contributions | 1 | - |
| Plan Conversion | 30 | - |
| Remeasurements: | | |
| (Gains) Losses from Experience Adjustments | 3 | 1 |
| (Gains) Losses from Changes in Demographic Assumptions | - | (1) |
| (Gains) Losses from Changes in Financial Assumptions | 4 | (2) |
| **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 | - |
| Employer Contributions | 22 | |
| Plan Participant Contributions | 1 | - |
| Benefits Paid | (2) | - |
| Interest Income (1) | 3 | - |
| Asset Transfer from Plan Conversion | 12 | - |
| Remeasurements: | | |
| Return on Plan Assets (Excluding Interest Income) | 1 | - |
| **Fair Value of Plan Assets, December 31, 2012** | 94 | - |
| **Pension and Other Post-Employment Benefit (Liability) (2)** | (40) | (20) |

*(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.*
*(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.*

### 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. The disclosures related to fair value measurement can be found in Note 21.

### 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 OCI.

### E) Disclosure of 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 21. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

### F) Disclosures of Recoverable Amounts of Non-Financial Assets

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a cash-generating unit ("CGU"). The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, the Company early adopted the amendment in the current period. Refer to Note 14 for the amended disclosures.

### G) Future Accounting Pronouncements

A description of additional standards and interpretations that will be adopted by the Company in future periods are as follows:

#### *Financial Instruments*

The IASB intends to replace International Accounting Standard 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. Cenovus does not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

***Offsetting Financial Assets and Financial Liabilities***

In December 2011, the IASB issued amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on the Consolidated Financial Statements.

## 4. FINANCE COSTS

| For the period ended December 31, | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|
| Interest Expense – Short-Term Borrowings and Long-Term Debt | **68** | 64 | **271** | 230 |
| Premium on Redemption of Long-Term Debt (Note 15) | **-** | - | **33** | - |
| Interest Expense – Partnership Contribution Payable | **23** | 27 | **98** | 118 |
| Unwinding of Discount on Decommissioning Liabilities | **25** | 22 | **97** | 86 |
| Other | **6** | (2) | **30** | 21 |
| | **122** | 111 | **529** | 455 |

## 5. INTEREST INCOME

| For the period ended December 31, | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|
| Interest Income – Partnership Contribution Receivable | **(17)** | (23) | **(82)** | (102) |
| Other | **(6)** | (2) | **(14)** | (7) |
| | **(23)** | (25) | **(96)** | (109) |

## 6. FOREIGN EXCHANGE (GAIN) LOSS, NET

| For the period ended December 31, | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|
| Unrealized Foreign Exchange (Gain) Loss on Translation of: | | | | |
| U.S. Dollar Debt Issued from Canada | **167** | 53 | **357** | (69) |
| U.S. Dollar Partnership Contribution Receivable Issued from Canada | **(206)** | (37) | **(305)** | (15) |
| Other | **(7)** | (4) | **(12)** | 14 |
| **Unrealized Foreign Exchange (Gain) Loss** | **(46)** | 12 | **40** | (70) |
| **Realized Foreign Exchange (Gain) Loss** | **161** | 10 | **168** | 50 |
| | **115** | 22 | **208** | (20) |

## 7. INCOME TAXES

The provision for income taxes is as follows:

| For the period ended December 31, | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|
| Current Tax | | | | |
| Canada | **(4)** | 49 | **143** | 188 |
| United States (1) | **7** | 76 | **45** | 121 |
| **Total Current Tax** | **3** | 125 | **188** | 309 |
| **Deferred Tax** | **33** | 66 | **244** | 474 |
| | **36** | 191 | **432** | 783 |

*(1) 2012 includes $68 million of withholding tax on a U.S. dividend.*

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

| For the period ended December 31, | Twelve Months Ended 2013 | 2012 |
|---|---|---|
| **Earnings Before Income Tax** | **1,094** | 1,778 |
| Canadian Statutory Rate | **25.2%** | 25.2% |
| **Expected Income Tax** | **276** | 448 |
| Effect of Taxes Resulting from: | | |
| Foreign Tax Rate Differential | **109** | 146 |
| Non-Deductible Stock-Based Compensation | **10** | 10 |
| Multi-Jurisdictional Financing | **(22)** | (27) |
| Foreign Exchange Gains (Losses) Not Included in Net Earnings | **19** | 14 |
| Non-Taxable Capital (Gains) Losses | **31** | (7) |
| Derecognition (Recognition) of Capital Losses | **15** | (22) |
| Adjustments Arising from Prior Year Tax Filings | **(13)** | 33 |
| Withholding Tax on Foreign Dividend | **-** | 68 |
| Goodwill Impairment | **-** | 99 |
| Other | **7** | 21 |
| **Total Tax** | **432** | 783 |
| **Effective Tax Rate** | **39.5%** | 44.0% |

## 8. PER SHARE AMOUNTS

### A) Net Earnings Per Share

| For the period ended December 31, ($ millions, except net earnings per share) | Three Months Ended 2013 | 2012 | Twelve Months Ended 2013 | 2012 |
|---|---|---|---|---|
| Net Earnings (Loss) – Basic and Diluted | **(58)** | (117) | **662** | 995 |
| Weighted Average Number of Shares – Basic | **755.9** | 755.8 | **755.9** | 755.6 |
| Dilutive Effect of Cenovus TSARs | **1.3** | 2.5 | **1.6** | 2.9 |
| Dilutive Effect of NSRs | **-** | - | **-** | - |
| Weighted Average Number of Shares – Diluted | **757.2** | 758.3 | **757.5** | 758.5 |
| Net Earnings (Loss) Per Share – Basic | **$(0.08)** | $(0.15) | **$0.88** | $1.32 |
| Net Earnings (Loss) Per Share – Diluted | **$(0.08)** | $(0.15) | **$0.87** | $1.31 |

### B) Dividends Per Share

The Company paid dividends of $732 million or $0.968 per share for the year ended December 31, 2013 (December 31, 2012 – $665 million, $0.88 per share). The Cenovus Board of Directors declared a first quarter dividend of $0.2662 per share, payable on March 31, 2014, to common shareholders of record as of March 14, 2014.

## 9. PARTNERSHIP CONTRIBUTION RECEIVABLE

Through its interest in the FCCL joint operation, Cenovus's Consolidated Balance Sheets included a Partnership Contribution Receivable. On December 17, 2013, Cenovus received US$1.4 billion, representing the remaining principal and interest due under the Partnership Contribution Receivable.

## 10. INVENTORIES

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| **Product** | | |
| Refining and Marketing | **1,047** | 1,056 |
| Oil Sands | **156** | 192 |
| Conventional | **17** | 11 |
| **Parts and Supplies** | **39** | 29 |
| | **1,259** | 1,288 |

In the third quarter, Cenovus recorded a $28 million write-down of its product inventory as a result of a decline in refined product prices. Product turnover and the subsequent improvement in commodity prices have resulted in the $28 million being reversed in the fourth quarter.

## 11. ASSETS AND LIABILITIES HELD FOR SALE

In the first quarter of 2013, Management decided to launch a public sales process to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. At that time, the assets were recorded at the lesser of fair value less costs of disposal and their carrying amount, and depletion ceased. These assets and the related liabilities are reported in the Conventional segment.

In July 2013, the Company completed the sale of the Lower Shaunavon asset to an unrelated third party for proceeds of approximately $240 million plus closing adjustments. In the second quarter of 2013, an impairment loss of $57 million was recorded as additional depreciation, depletion and amortization ("DD&A") on the transaction. A loss of $2 million was recorded on the sale in the third quarter.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received for the Bakken assets. As a result of this decision, as at December 31, 2013, the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities, at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter. The carrying value continues to be less than the estimated recoverable amount; therefore, no impairment was recognized.

## 12. EXPLORATION AND EVALUATION ASSETS

| | |
|---|---|
| **COST** | |
| As at December 31, 2011 | 880 |
| Additions [1] | 687 |
| Transfers to PP&E (Note 13) | (218) |
| Exploration Expense | (68) |
| Divestitures | (11) |
| Change in Decommissioning Liabilities | 15 |
| As at December 31, 2012 | 1,285 |
| Additions | 331 |
| Transfers to PP&E (Note 13) | (95) |
| Exploration Expense | (50) |
| Divestitures | (17) |
| Change in Decommissioning Liabilities | 19 |
| **As at December 31, 2013** | **1,473** |

*(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 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 year ended December 31, 2013 include $60 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 year ended December 31, 2013 or December 31, 2012.

For the year ended December 31, 2013, $95 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. For the year ended December 31, 2013, $50 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 (year ended December 31, 2012 – $68 million).

## 13. 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 12) | 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 | 2,702 | 48 | 106 | 82 | 2,938 |
| Transfers from E&E Assets (Note 12) | 95 | - | - | - | 95 |
| Transfers and Reclassifications | (450) | - | (88) | - | (538) |
| Change in Decommissioning Liabilities | 40 | - | (1) | - | 39 |
| Exchange Rate Movements | - | - | 238 | - | 238 |
| **As at December 31, 2013** | **29,390** | **286** | **3,654** | **849** | **34,179** |
| **ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION** | | | | | |
| As at December 31, 2011 | 13,021 | 139 | 225 | 344 | 13,729 |
| Depreciation, Depletion and Amortization | 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, Depletion and Amortization | 1,522 | 35 | 138 | 79 | 1,774 |
| Transfers and Reclassifications | (123) | - | (88) | - | (211) |
| Impairment Losses | 2 | - | - | - | 2 |
| Exchange Rate Movements | - | - | 25 | - | 25 |
| **As at December 31, 2013** | **15,791** | **193** | **386** | **475** | **16,845** |
| **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 December 31, 2013** | **13,599** | **93** | **3,268** | **374** | **17,334** |

*(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 $204 million for the year ended December 31, 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 year ended December 31, 2013 or December 31, 2012.

PP&E includes the following amounts in respect of assets under construction and are not subject to DD&A:

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Development and Production | **225** | 71 |
| Refining Equipment | **97** | 13 |
| | **322** | 84 |

## 14. GOODWILL

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Carrying Value, Beginning of Year | **739** | 1,132 |
| Impairment | **-** | (393) |
| **Carrying Value, End of Year** | **739** | 739 |

There were no goodwill additions for 2013 or 2012.

### Impairment Test for CGUs Containing Goodwill

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. The carrying amount of goodwill allocated to the Company's exploration and production CGUs was:

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Primrose (Foster Creek) | **242** | 242 |
| Northern Alberta | **497** | 497 |
| | **739** | 739 |

At December 31, 2012, the Company determined that the carrying amount of the Suffield CGU exceeded its fair value less costs of disposal and the full amount of the impairment was attributed to goodwill. An impairment loss of $393 million was recorded as goodwill impairment on the Consolidated Statement of Earnings and Comprehensive Income. The Suffield property resides on the Canadian Forces Base in southeast Alberta and the operating results are included in the Conventional segment. Future cash flows for the area declined due to lower natural gas and crude oil prices and increased operating costs. In addition, minimal levels of capital spending for natural gas resulted in production exceeding reserves replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the Suffield CGU exceeded its fair value.

The recoverable amount was determined using fair value less costs of disposal. A calculation based on discounted after-tax cash flows of proved and probable reserves using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators was completed. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2012, the recoverable amount of the Suffield CGU was $1,130 million.

There were no impairments of goodwill in 2013.

## 15. LONG-TERM DEBT

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Revolving Term Debt [1] | **-** | - |
| U.S. Dollar Denominated Unsecured Notes | **5,052** | 4,726 |
| **Total Debt Principal** | **5,052** | 4,726 |
| Debt Discounts and Transaction Costs | **(55)** | (47) |
| | **4,997** | 4,679 |

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

As at December 31, 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 US$2.0 billion to US$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 December 31, 2013, US$1.2 billion remains under this U.S. shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 15, 2013, Cenovus completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$800 million under the Company's U.S. base shelf prospectus. The senior unsecured notes issued are as follows:

| | **US$ Principal Amount** | **December 31, 2013** |
|---|---|---|
| 3.8% due 2023 | **450** | **479** |
| 5.2% due 2043 | **350** | **372** |
| | **800** | **851** |

The net proceeds from the offering were used to partially fund the early redemption of Cenovus's US$800 million senior unsecured notes due September 2014. A premium of US$32 million was paid in the third quarter on the early redemption of these notes and recorded as finance costs.

In September 2013, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2017.

## 16. 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 | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Decommissioning Liabilities, Beginning of Year | **2,315** | 1,777 |
| Liabilities Incurred | **45** | 99 |
| Liabilities Settled | **(76)** | (66) |
| Transfers and Reclassifications | **(26)** | 3 |
| Change in Estimated Future Cash Flows | **414** | 144 |
| Change in Discount Rate | **(401)** | 273 |
| Unwinding of Discount on Decommissioning Liabilities | **97** | 86 |
| Foreign Currency Translation | **2** | (1) |
| **Decommissioning Liabilities, End of Year** | **2,370** | 2,315 |

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 5.2 percent as at December 31, 2013 (December 31, 2012 – 4.2 percent). Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. Revisions in estimated future cash flows resulted from accelerated timing of forecast abandonment and reclamation spending, and higher cost estimates.

## 17. 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

| | **December 31, 2013** | | December 31, 2012 | |
|---|---|---|---|---|
| As at | **Number of Common Shares** (thousands) | **Amount** | Number of Common Shares (thousands) | Amount |
| Outstanding, Beginning of Year | **755,843** | **3,829** | 754,499 | 3,780 |
| Common Shares Issued under Stock Option Plans | **970** | **31** | 1,344 | 49 |
| Common Shares Cancelled | **(767)** | **(3)** | - | - |
| **Outstanding, End of Year** | **756,046** | **3,857** | 755,843 | 3,829 |

During the year ended December 31, 2013, the Company cancelled 767,327 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 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 December 31, 2013 (December 31, 2012 – nil).

As at December 31, 2013, there were 24 million (December 31, 2012 – 28 million) common shares available for future issuance under stock option plans.

## 18. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

| As at December 31, 2013 | **Defined Benefit Plan** | **Foreign Currency Translation** | **Available for Sale Investments** | **Total** |
|---|---|---|---|---|
| Balance, Beginning of Year | **(26)** | **95** | **-** | **69** |
| Other Comprehensive Income, Before Tax | **18** | **117** | **13** | **148** |
| Income Tax | **(4)** | **-** | **(3)** | **(7)** |
| **Balance, End of Year** | **(12)** | **212** | **10** | **210** |

| As at December 31, 2012 | **Defined Benefit Plan** | **Foreign Currency Translation** | **Available for Sale Investments** | **Total** |
|---|---|---|---|---|
| Balance, Beginning of Year | (22) | 119 | - | 97 |
| Other Comprehensive Income, Before Tax | (4) | (24) | - | (28) |
| Income Tax | - | - | - | - |
| **Balance, End of Year** | (26) | 95 | - | 69 |

## 19. 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 December 31, 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 | 5.46 | 35.26 | 30.40 | 26,315 |
| TSARs | Prior to February 17, 2010 | 5 | 0.15 | 26.28 | 30.40 | 2,483 |
| TSARs | On or After February 17, 2010 | 7 | 3.20 | 26.71 | 30.40 | 4,603 |
| Encana Replacement TSARs held by Cenovus Employees | Prior to December 1, 2009 | 5 | 0.12 | 29.06 | 19.18 | 3,904 |
| Cenovus Replacement TSARs held by Encana Employees | Prior to December 1, 2009 | 5 | 0.12 | 26.28 | 30.40 | 1,479 |

#### *NSRs*

The weighted average unit fair value of NSRs granted during the year ended December 31, 2013 was $6.10 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 December 31, 2013 | Number of NSRs (thousands) | Weighted Average Exercise Price ($) |
|---|---|---|
| Outstanding, Beginning of Year | 15,074 | 37.52 |
| Granted | 12,078 | 32.50 |
| Exercised for Common Shares | - | 31.85 |
| Forfeited | (837) | 36.26 |
| **Outstanding, End of Year** | 26,315 | 35.26 |
| **Exercisable, End of Year** | 5,966 | 37.37 |

#### *TSARs Held by Cenovus Employees*

The Company has recorded a liability of $33 million at December 31, 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 December 31, 2013 was $27 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 December 31, 2013 | Number of TSARs (thousands) | Weighted Average Exercise Price ($) |
|---|---|---|
| Outstanding, Beginning of Year | 11,251 | 28.13 |
| Exercised for Cash Payment | (1,840) | 29.70 |
| Exercised as Options for Common Shares | (955) | 29.07 |
| Forfeited | (67) | 28.62 |
| Expired | (1,303) | 33.77 |
| **Outstanding, End of Year** | 7,086 | 26.56 |
| **Exercisable, End of Year** | 7,037 | 26.51 |

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.60.

***Encana Replacement TSARs Held by Cenovus Employees***

The Company has recorded a liability of $nil as at December 31, 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 December 31, 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 December 31, 2013 | Number of TSARs (thousands) | Weighted Average Exercise Price ($) |
|---|---|---|
| Outstanding, Beginning of Year | 7,722 | 32.66 |
| Forfeited | (187) | 30.07 |
| Expired | (3,631) | 36.66 |
| **Outstanding, End of Year** | **3,904** | **29.06** |
| **Exercisable, End of Year** | **3,904** | **29.06** |

The closing price of Encana common shares on the TSX as at December 31, 2013 was $19.18.

***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 $6 million as at December 31, 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 December 31, 2013 was $6 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 December 31, 2013 | Number of TSARs (thousands) | Weighted Average Exercise Price ($) |
|---|---|---|
| Outstanding, Beginning of Year | 5,229 | 29.29 |
| Exercised for Cash Payment | (2,351) | 28.75 |
| Exercised as Options for Common Shares | (15) | 29.54 |
| Forfeited | (27) | 28.74 |
| Expired | (1,357) | 33.51 |
| **Outstanding, End of Year** | **1,479** | **26.28** |
| **Exercisable, End of Year** | **1,479** | **26.28** |

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.42.

### B) Performance Share Units

The Company has recorded a liability of $103 million as at December 31, 2013 (December 31, 2012 – $124 million) for performance share units ("PSUs") based on the market value of Cenovus's common shares at December 31, 2013. As PSUs are paid out upon vesting, the intrinsic value was $nil at December 31, 2013 and December 31, 2012.

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

| As at December 31, 2013 | Number of PSUs (thousands) |
|---|---|
| Outstanding, Beginning of Year | **5,258** |
| Granted | **2,552** |
| Vested and Paid Out | **(2,008)** |
| Cancelled | **(194)** |
| Units in Lieu of Dividends | **177** |
| **Outstanding, End of Year** | **5,785** |

### C) Deferred Share Units

The Company has recorded a liability of $36 million as at December 31, 2013 (December 31, 2012 – $36 million) for deferred share units ("DSUs") based on the market value of Cenovus's common shares at December 31, 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 December 31, 2013 | Number of DSUs (thousands) |
|---|---|
| Outstanding, Beginning of Year | **1,084** |
| Granted to Directors | **65** |
| Granted from Annual Bonus Awards | **8** |
| Units in Lieu of Dividends | **36** |
| Redeemed | **(1)** |
| **Outstanding, End of Year** | **1,192** |

### 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 | | Twelve Months Ended | |
|---|---|---|---|---|
| For the period ended December 31, | **2013** | 2012 | **2013** | 2012 |
| NSRs | **9** | 5 | **35** | 27 |
| TSARs Held by Cenovus Employees | **(5)** | (1) | **(16)** | (1) |
| Encana Replacement TSARs Held by Cenovus Employees | **-** | (1) | **-** | - |
| PSUs | **-** | 7 | **32** | 46 |
| DSUs | **-** | (1) | **-** | 3 |
| **Stock-Based Compensation Expense (Recovery)** | **4** | 9 | **51** | 75 |

## 20. 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 and DD&A ("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 | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Long-Term Debt | **4,997** | 4,679 |
| Shareholders' Equity | **9,946** | 9,782 |
| Capitalization | **14,943** | 14,461 |
| **Debt to Capitalization** | **33%** | 32% |

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

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| Debt | **4,997** | 4,679 |
| Net Earnings | **662** | 995 |
| Add (Deduct): | | |
| Finance Costs | **529** | 455 |
| Interest Income | **(96)** | (109) |
| Income Tax Expense | **432** | 783 |
| Depreciation, Depletion and Amortization | **1,833** | 1,585 |
| Goodwill Impairment | **-** | 393 |
| E&E Impairment | **50** | 68 |
| Unrealized (Gain) Loss on Risk Management | **415** | (57) |
| Foreign Exchange (Gain) Loss, Net | **208** | (20) |
| (Gain) Loss on Divestitures of Assets | **1** | - |
| Other (Income) Loss, Net | **2** | (5) |
| Adjusted EBITDA | **4,036** | 4,088 |
| **Debt to Adjusted EBITDA** | **1.2x** | 1.1x |

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.

As at December 31, 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$1.2 billion under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

As at December 31, 2013, Cenovus is in compliance with all of the terms of its debt agreements.

## 21. 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 December 31, 2013 range from $44.75 to $66.00 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 December 31, 2013, the carrying value of Cenovus's long-term debt was $4,997 million and the fair value was $5,388 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. Fair value is determined based on recent private placement transactions (Level 3) when available. When fair value cannot be reliably measured, these assets are carried at cost. Available for sale financial assets are included in other assets on the Consolidated Balance Sheets.

## B) Risk Management Assets and Liabilities

### *Net Risk Management Position*

| As at | **December 31, 2013** | December 31, 2012 |
|---|---|---|
| **Risk Management Assets** | | |
| Current Asset | **10** | 283 |
| Long-Term Asset | **-** | 5 |
| | **10** | 288 |
| **Risk Management Liabilities** | | |
| Current Liability | **136** | 17 |
| Long-Term Liability | **3** | 1 |
| | **139** | 18 |
| **Net Risk Management Asset (Liability)** | **(129)** | 270 |

### *Summary of Unrealized Risk Management Positions*

| | **December 31, 2013** | | | December 31, 2012 | | |
|---|---|---|---|---|---|---|
| | **Risk Management** | | | Risk Management | | |
| As at | **Asset** | **Liability** | **Net** | Asset | Liability | Net |
| **Commodity Prices** | | | | | | |
| Crude Oil | **10** | **136** | **(126)** | 221 | 16 | 205 |
| Natural Gas | **-** | **-** | **-** | 66 | 1 | 65 |
| Power | **-** | **3** | **(3)** | 1 | 1 | - |
| **Fair Value** | **10** | **139** | **(129)** | 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.

The following table provides a summary of the Company's offsetting risk management positions:

| | **December 31, 2013** | | | December 31, 2012 | | |
|---|---|---|---|---|---|---|
| | **Risk Management** | | | Risk Management | | |
| As at | **Asset** | **Liability** | **Net** | Asset | Liability | Net |
| **Recognized Risk Management Positions** | | | | | | |
| Gross Amount | **16** | **145** | **(129)** | 306 | 36 | 270 |
| Amount Offset | **(6)** | **(6)** | **-** | (18) | (18) | - |
| **Net Amount per Consolidated Financial Statements** | **10** | **139** | **(129)** | 288 | 18 | 270 |

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2013, $10 million (December 31, 2012 – $12 million) was pledged as collateral, of which $5 million (December 31, 2012 – $12 million) could have been withdrawn.

### *Net Fair Value Methodologies Used to Calculate Unrealized Risk Management Positions*

| As at | December 31, 2013 | December 31, 2012 |
|---|---|---|
| **Prices Sourced from Observable Data or Market Corroboration (Level 2)** | **(126)** | 270 |
| **Prices Determined from Unobservable Inputs (Level 3)** | **(3)** | - |
| | **(129)** | 270 |

### *Net Fair Value of Commodity Price Positions at December 31, 2013*

| | Notional Volumes | Term | Average Price | Fair Value |
|---|---|---|---|---|
| **Crude Oil Contracts** | | | | |
| Fixed Price Contracts | | | | |
| Brent Fixed Price | 30,000 bbls/d | 2014 | US$102.04/bbl | **(73)** |
| Brent Fixed Price | 20,000 bbls/d | 2014 | $107.06/bbl | **(64)** |
| WCS Differential (1) | 15,900 bbls/d | 2014 | US$(20.39)/bbl | **10** |
| Other Financial Positions (2) | | | | **1** |
| Crude Oil Fair Value Position | | | | **(126)** |
| **Power Purchase Contracts** | | | | |
| Power Fair Value Position | | | | **(3)** |

*(1) Cenovus entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.*
*(2) Other financial positions are part of ongoing operations to market the Company's production.*

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

| | Three Months Ended | | Twelve Months Ended | |
|---|---|---|---|---|
| For the period ended December 31, | 2013 | 2012 | 2013 | 2012 |
| **Realized Gain (Loss) (1)** | | | | |
| Crude Oil | **49** | 55 | **71** | 81 |
| Natural Gas | **17** | 47 | **63** | 247 |
| Refining | **12** | (11) | **(18)** | 7 |
| Power | **(1)** | 1 | **6** | 1 |
| | **77** | 92 | **122** | 336 |
| **Unrealized Gain (Loss) (2)** | | | | |
| Crude Oil | **(196)** | 145 | **(343)** | 247 |
| Natural Gas | **(18)** | (32) | **(69)** | (176) |
| Refining | **(1)** | 4 | **-** | 1 |
| Power | **(4)** | - | **(3)** | (15) |
| | **(219)** | 117 | **(415)** | 57 |
| **Gain (Loss) on Risk Management** | **(142)** | 209 | **(293)** | 393 |

*(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 December 31, 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 Year | (293) | (293) | 393 |
| Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts | 16 | - | - |
| Fair Value of Contracts Realized During the Year | (122) | (122) | (336) |
| **Fair Value of Contracts, End of Year** | (129) | (415) | 57 |

***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 December 31, 2013 could have resulted in unrealized gains (losses) impacting earnings before income tax for the year ended December 31, 2013 as follows:

**Risk Management Positions in Place as at December 31, 2013**

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10 per bbl Applied to Brent, WTI and Condensate Hedges | (200) | 200 |
| Crude Oil Differential Price | ± US$5 per bbl Applied to Differential Hedges tied to Production | 31 | (31) |
| 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.

## 22. COMMITMENTS AND CONTINGENCIES

### A) Commitments

During the year ended December 31, 2013 the Company entered into various firm transportation agreements totaling approximately $11 billion. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement. In addition, Cenovus entered into an office lease agreement totaling approximately $1 billion over a 22 year term beginning upon completion of construction of the building expected in late 2017.

### 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** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| Gross Sales | | | | | | | | | | |
| Upstream | **6,892** | **1,767** | 1,926 | 1,646 | 1,553 | **6,156** | 1,584 | 1,496 | 1,382 | 1,694 |
| Refining and Marketing | **12,706** | **3,223** | 3,459 | 3,078 | 2,946 | **11,356** | 2,336 | 3,066 | 2,962 | 2,992 |
| Corporate and Eliminations | **(605)** | **(163)** | (190) | (130) | (122) | **(283)** | (118) | (100) | (65) | - |
| Less: Royalties | **336** | **80** | 120 | 78 | 58 | **387** | 78 | 122 | 65 | 122 |
| **Revenues** | **18,657** | **4,747** | 5,075 | 4,516 | 4,319 | **16,842** | 3,724 | 4,340 | 4,214 | 4,564 |
| **Operating Cash Flow** | | | | | | | | | | |
| Crude Oil and Natural Gas Liquids | | | | | | | | | | |
| Foster Creek | **877** | **204** | 252 | 232 | 189 | **924** | 246 | 227 | 223 | 228 |
| Christina Lake | **596** | **179** | 248 | 96 | 73 | **343** | 118 | 93 | 70 | 62 |
| Pelican Lake | **385** | **92** | 130 | 96 | 67 | **418** | 98 | 108 | 85 | 127 |
| Other Conventional | **1,003** | **232** | 285 | 251 | 235 | **962** | 240 | 227 | 228 | 267 |
| Natural Gas | **437** | **110** | 94 | 118 | 115 | **513** | 134 | 126 | 121 | 132 |
| Other Upstream Operations | **27** | **8** | 5 | 8 | 6 | **18** | 7 | 5 | 1 | 5 |
| | **3,325** | **825** | 1,014 | 801 | 685 | **3,178** | 843 | 786 | 728 | 821 |
| Refining and Marketing | **1,143** | **151** | 139 | 324 | 529 | **1,273** | 123 | 528 | 353 | 269 |
| **Operating Cash Flow** [1] | **4,468** | **976** | 1,153 | 1,125 | 1,214 | **4,451** | 966 | 1,314 | 1,081 | 1,090 |
| **Cash Flow Information** | | | | | | | | | | |
| Cash from Operating Activities | **3,539** | **976** | 840 | 828 | 895 | **3,420** | 758 | 1,029 | 968 | 665 |
| Deduct (Add back): | | | | | | | | | | |
| Net Change in Other Assets and Liabilities | **(120)** | **(30)** | (25) | (31) | (34) | **(113)** | (42) | (19) | (20) | (32) |
| Net Change in Non-Cash Working Capital | **50** | **171** | (67) | (12) | (42) | **(110)** | 103 | (69) | 63 | (207) |
| **Cash Flow** [2] | **3,609** | **835** | 932 | 871 | 971 | **3,643** | 697 | 1,117 | 925 | 904 |
| Per Share - Basic | **4.77** | **1.10** | 1.23 | 1.15 | 1.28 | **4.82** | 0.92 | 1.48 | 1.22 | 1.20 |
| - Diluted | **4.76** | **1.10** | 1.23 | 1.15 | 1.28 | **4.80** | 0.92 | 1.47 | 1.22 | 1.19 |
| **Operating Earnings** [3] | **1,171** | **212** | 313 | 255 | 391 | **868** | (188) | 432 | 284 | 340 |
| Per Share - Diluted | **1.55** | **0.28** | 0.41 | 0.34 | 0.52 | **1.14** | (0.25) | 0.57 | 0.37 | 0.45 |
| **Net Earnings (Loss)** | **662** | **(58)** | 370 | 179 | 171 | **995** | (117) | 289 | 397 | 426 |
| Per Share - Basic | **0.88** | **(0.08)** | 0.49 | 0.24 | 0.23 | **1.32** | (0.15) | 0.38 | 0.53 | 0.56 |
| - Diluted | **0.87** | **(0.08)** | 0.49 | 0.24 | 0.23 | **1.31** | (0.15) | 0.38 | 0.52 | 0.56 |
| **Effective Tax Rates using** | | | | | | | | | | |
| Net Earnings | **39.5%** | | | | | **44.0%** | | | | |
| Operating Earnings, excluding Divestitures | **31.4%** | | | | | **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 | **0.971** | **0.953** | 0.963 | 0.977 | 0.992 | **1.001** | 1.009 | 1.005 | 0.990 | 0.999 |
| Period end | **0.940** | **0.940** | 0.972 | 0.951 | 0.985 | **1.005** | 1.005 | 1.017 | 0.981 | 1.001 |

(1) Operating cash flow is a non-GAAP measure defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.

(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, the effect of changes in statutory income tax rates and after-tax realized foreign exchange loss on early receipt of the Partnership Contribution Receivable.

### Financial Metrics (Non-GAAP measures)

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| Debt to Capitalization [4], [5] | **33%** | **33%** | 32% | 33% | 33% | **32%** | 32% | 32% | 27% | 28% |
| Net Debt to Capitalization [4], [6] | **29%** | **29%** | 28% | 30% | 28% | **27%** | 27% | 24% | 25% | 25% |
| Debt to Adjusted EBITDA [5], [7] | **1.2x** | **1.2x** | 1.2x | 1.2x | 1.1x | **1.1x** | 1.1x | 1.1x | 1.0x | 1.0x |
| Net Debt to Adjusted EBITDA [6], [7] | **1.0x** | **1.0x** | 1.0x | 1.0x | 0.9x | **0.9x** | 0.9x | 0.8x | 0.9x | 0.9x |
| Return on Capital Employed [8] | **6%** | **6%** | 6% | 5% | 7% | **9%** | 9% | 11% | 14% | 16% |
| Return on Common Equity [9] | **7%** | **7%** | 6% | 5% | 8% | **10%** | 10% | 14% | 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) Net debt includes the Company's short-term borrowings, current and long-term portions of long-term debt and the current and long-term portions of the Partnership Contribution Payable, net of cash and cash equivalents and the current and long-term portions of the Partnership Contribution Receivable.

(7) We define trailing 12-month Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net.

(8) Return on capital employed is calculated, on a trailing 12-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.

(9) Return on common equity is calculated, on a trailing 12-month basis, as net earnings divided by average shareholders' equity.

## Financial Statistics (continued)

### Common Share Information

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Common Shares Outstanding** *(millions)* | | | | | | | | | | |
| Period end | **756.0** | **756.0** | 755.8 | 755.8 | 755.8 | **755.8** | 755.8 | 755.8 | 755.7 | 755.6 |
| Average - Basic | **755.9** | **755.9** | 755.8 | 755.8 | 756.0 | **755.6** | 755.8 | 755.7 | 755.7 | 755.1 |
| Average - Diluted | **757.5** | **757.2** | 757.2 | 757.1 | 758.4 | **758.5** | 758.3 | 758.0 | 757.9 | 759.5 |
| **Price Range** *($ per share)* | | | | | | | | | | |
| TSX - C$ | | | | | | | | | | |
| High | **34.13** | **31.69** | 32.77 | 32.08 | 34.13 | **39.64** | 35.69 | 36.25 | 36.68 | 39.64 |
| Low | **28.32** | **29.33** | 28.98 | 28.32 | 31.09 | **30.09** | 31.82 | 30.37 | 30.09 | 33.24 |
| Close | **30.40** | **30.40** | 30.74 | 30.00 | 31.46 | **33.29** | 33.29 | 34.31 | 32.37 | 35.90 |
| NYSE - US$ | | | | | | | | | | |
| High | **34.50** | **30.34** | 31.60 | 31.58 | 34.50 | **39.81** | 36.11 | 37.31 | 37.26 | 39.81 |
| Low | **27.25** | **27.60** | 28.00 | 27.25 | 30.58 | **28.83** | 31.74 | 30.20 | 28.83 | 32.45 |
| Close | **28.65** | **28.65** | 29.85 | 28.52 | 30.99 | **33.54** | 33.54 | 34.85 | 31.80 | 35.94 |
| **Dividends Paid** *($ per share)* | **$ 0.968** | **$ 0.242** | $ 0.242 | $ 0.242 | $ 0.242 | **$ 0.88** | $ 0.22 | $ 0.22 | $ 0.22 | $ 0.22 |
| **Share Volume Traded** *(millions)* | **685.7** | **146.2** | 183.0 | 201.6 | 154.9 | **664.3** | 141.7 | 152.6 | 192.6 | 177.4 |

### Net Capital Investment

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Capital Investment** *($ millions)* | | | | | | | | | | |
| Oil Sands | | | | | | | | | | |
| Foster Creek | **797** | **193** | 205 | 189 | 210 | **735** | 208 | 199 | 169 | 159 |
| Christina Lake | **688** | **189** | 162 | 162 | 175 | **593** | 168 | 147 | 140 | 138 |
| Total | **1,485** | **382** | 367 | 351 | 385 | **1,328** | 376 | 346 | 309 | 297 |
| Other Oil Sands | **398** | **120** | 60 | 69 | 149 | **365** | 82 | 42 | 41 | 200 |
| | **1,883** | **502** | 427 | 420 | 534 | **1,693** | 458 | 388 | 350 | 497 |
| Conventional | | | | | | | | | | |
| Pelican Lake | **465** | **115** | 96 | 111 | 143 | **518** | 147 | 128 | 104 | 139 |
| Other Conventional | **726** | **216** | 178 | 134 | 198 | **848** | 257 | 231 | 129 | 231 |
| | **1,191** | **331** | 274 | 245 | 341 | **1,366** | 404 | 359 | 233 | 370 |
| Refining and Marketing | **107** | **37** | 19 | 26 | 25 | **118** | 58 | 38 | 24 | (2) |
| Corporate | **81** | **28** | 23 | 15 | 15 | **191** | 58 | 45 | 53 | 35 |
| Capital Investment | **3,262** | **898** | 743 | 706 | 915 | **3,368** | 978 | 830 | 660 | 900 |
| Acquisitions [1] | **32** | **27** | 1 | 1 | 3 | **114** | 70 | 8 | 28 | 8 |
| Divestitures | **(283)** | **(41)** | (241) | - | (1) | **(76)** | (11) | - | 1 | (66) |
| Net Acquisition and Divestiture Activity | **(251)** | **(14)** | (240) | 1 | 2 | **38** | 59 | 8 | 29 | (58) |
| **Net Capital Investment** | **3,011** | **884** | 503 | 707 | 917 | **3,406** | 1,037 | 838 | 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** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Crude Oil and Natural Gas Liquids** *(bbls/d)* | | | | | | | | | | |
| Oil Sands - Heavy Oil | | | | | | | | | | |
| Foster Creek | **53,190** | **52,419** | 49,092 | 55,338 | 55,996 | **57,833** | 59,059 | 63,245 | 51,740 | 57,214 |
| Christina Lake | **49,310** | **61,471** | 52,732 | 38,459 | 44,351 | **31,903** | 41,808 | 32,380 | 28,577 | 24,733 |
| Total | **102,500** | **113,890** | 101,824 | 93,797 | 100,347 | **89,736** | 100,867 | 95,625 | 80,317 | 81,947 |
| Conventional Liquids | | | | | | | | | | |
| Pelican Lake | **24,254** | **24,528** | 24,826 | 23,959 | 23,687 | **22,552** | 23,507 | 23,539 | 22,410 | 20,730 |
| Other Heavy Oil | **15,991** | **15,480** | 15,507 | 16,284 | 16,712 | **16,015** | 16,243 | 15,492 | 15,703 | 16,624 |
| Light and Medium Oil | **35,467** | **33,646** | 33,651 | 36,137 | 38,508 | **36,071** | 36,034 | 35,695 | 36,149 | 36,411 |
| Natural Gas Liquids [2] | **1,063** | **1,199** | 1,130 | 950 | 971 | **1,029** | 995 | 999 | 987 | 1,138 |
| Total Crude Oil and Natural Gas Liquids | **179,275** | **188,743** | 176,938 | 171,127 | 180,225 | **165,403** | 177,646 | 171,350 | 155,566 | 156,850 |
| **Natural Gas** *(MMcf/d)* | | | | | | | | | | |
| Oil Sands | **21** | **21** | 23 | 22 | 18 | **30** | 27 | 24 | 31 | 39 |
| Conventional | **508** | **493** | 500 | 514 | 527 | **564** | 539 | 553 | 565 | 597 |
| Total Natural Gas | **529** | **514** | 523 | 536 | 545 | **594** | 566 | 577 | 596 | 636 |
| **Total Production** *(BOE/d)* | **267,442** | **274,410** | 264,105 | 260,460 | 271,058 | **264,403** | 271,979 | 267,517 | 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** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Oil Sands** | | | | | | | | | | |
| Foster Creek | **5.8%** | **6.3%** | 7.6% | 5.7% | 2.9% | **11.8%** | 8.0% | 19.1% | 4.6% | 13.9% |
| Christina Lake | **6.8%** | **7.8%** | 7.0% | 5.6% | 5.7% | **6.2%** | 5.7% | 5.3% | 7.2% | 7.0% |
| **Conventional** | | | | | | | | | | |
| Pelican Lake | **5.9%** | **3.2%** | 7.7% | 5.8% | 6.2% | **5.0%** | 4.5% | 6.6% | 4.2% | 4.5% |
| Weyburn | **19.6%** | **16.8%** | 22.3% | 20.3% | 18.3% | **20.7%** | 17.9% | 19.8% | 21.4% | 23.3% |
| Other | **6.5%** | **7.4%** | 6.8% | 6.0% | 5.7% | **7.2%** | 7.1% | 6.6% | 6.8% | 8.3% |
| Natural Gas Liquids | **1.9%** | **1.9%** | 2.9% | 2.5% | 0.2% | **2.0%** | 2.3% | 2.5% | 1.7% | 1.7% |
| **Natural Gas** | **1.4%** | **1.2%** | 1.8% | 1.2% | 1.7% | **1.2%** | 0.9% | 0.8% | 0.4% | 2.5% |

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Operating Statistics - Before Royalties (continued)

#### Refining

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Refinery Operations** [(1)] | | | | | | | | | | |
| Crude oil capacity [(2)] *(Mbbls/d)* | **457** | **457** | 457 | 457 | 457 | **452** | 452 | 452 | 452 | 452 |
| Crude oil runs *(Mbbls/d)* | **442** | **447** | 464 | 439 | 416 | **412** | 311 | 442 | 451 | 445 |
| Heavy Oil | **222** | **221** | 240 | 230 | 197 | **198** | 155 | 210 | 229 | 199 |
| Light/Medium | **220** | **226** | 224 | 209 | 219 | **214** | 156 | 232 | 222 | 246 |
| Crude utilization | **97%** | **98%** | 101% | 96% | 91% | **91%** | 69% | 98% | 100% | 98% |
| Refined products *(Mbbls/d)* | **463** | **469** | 487 | 457 | 439 | **433** | 330 | 463 | 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 and January 1, 2014.

#### Selected Average Benchmark Prices

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Crude Oil Prices** *(US$/bbl)* | | | | | | | | | | |
| Brent | **108.70** | **109.35** | 109.65 | 103.35 | 112.64 | **111.68** | 110.13 | 109.42 | 108.76 | 118.45 |
| West Texas Intermediate ("WTI") | **98.05** | **97.61** | 105.81 | 94.17 | 94.36 | **94.15** | 88.23 | 92.20 | 93.35 | 103.03 |
| Differential Brent Futures-WTI | **10.65** | **11.74** | 3.84 | 9.18 | 18.28 | **17.53** | 21.90 | 17.22 | 15.41 | 15.42 |
| Western Canadian Select ("WCS") | **72.85** | **65.41** | 88.33 | 75.01 | 62.40 | **73.12** | 70.12 | 70.48 | 70.48 | 81.61 |
| Differential - WTI-WCS | **25.20** | **32.20** | 17.48 | 19.16 | 31.96 | **21.03** | 18.11 | 21.72 | 22.87 | 21.42 |
| Condensate - (C5 @ Edmonton) | **101.77** | **94.37** | 103.79 | 101.45 | 107.23 | **100.88** | 98.14 | 96.12 | 99.32 | 110.16 |
| Differential - WTI-Condensate (premium)/discount | **(3.72)** | **3.24** | 2.02 | (7.28) | (12.87) | **(6.73)** | (9.91) | (3.92) | (5.97) | (7.13) |
| **Refining Margins 3-2-1 Crack Spreads** [(3)] *(US$/bbl)* | | | | | | | | | | |
| Chicago | **21.77** | **12.29** | 16.19 | 31.06 | 27.53 | **27.76** | 28.18 | 35.64 | 28.20 | 19.00 |
| Midwest Combined (Group 3) | **20.80** | **10.66** | 17.35 | 27.24 | 27.93 | **28.56** | 28.49 | 35.99 | 28.28 | 21.50 |
| **Natural Gas Prices** | | | | | | | | | | |
| AECO *($/Mcf)* | **3.17** | **3.15** | 2.82 | 3.59 | 3.08 | **2.41** | 3.06 | 2.19 | 1.84 | 2.52 |
| NYMEX *(US$/Mcf)* | **3.65** | **3.60** | 3.58 | 4.09 | 3.34 | **2.79** | 3.40 | 2.81 | 2.22 | 2.74 |
| Differential - NYMEX-AECO *(US$/Mcf)* | **0.58** | **0.59** | 0.89 | 0.56 | 0.27 | **0.38** | 0.31 | 0.61 | 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 on a last in, first out accounting basis ("LIFO").

#### Per-unit Results

*(excluding impact of Realized Gain (Loss) on Risk Management)*

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Heavy Oil - Foster Creek** [(4)] *($/bbl)* | | | | | | | | | | |
| Price | **66.30** | **59.39** | 87.49 | 68.17 | 52.60 | **64.55** | 59.93 | 63.95 | 63.83 | 70.71 |
| Royalties | **3.73** | **3.56** | 6.31 | 3.87 | 1.47 | **7.36** | 4.55 | 11.79 | 2.85 | 9.54 |
| Transportation and Blending | **2.36** | **3.21** | 4.37 | 0.04 | 1.89 | **2.41** | 2.91 | 2.38 | 1.91 | 2.38 |
| Operating | **15.77** | **15.90** | 17.12 | 16.19 | 14.03 | **11.99** | 11.26 | 11.50 | 12.49 | 12.85 |
| Netback | **44.44** | **36.72** | 59.69 | 48.07 | 35.21 | **42.79** | 41.21 | 38.28 | 46.58 | 45.94 |
| **Heavy Oil - Christina Lake** [(4)] *($/bbl)* | | | | | | | | | | |
| Price | **51.26** | **44.36** | 74.98 | 52.61 | 33.41 | **47.73** | 43.37 | 52.91 | 44.57 | 52.58 |
| Royalties | **3.25** | **3.22** | 5.06 | 2.71 | 1.69 | **2.72** | 2.32 | 2.61 | 2.90 | 3.37 |
| Transportation and Blending | **3.55** | **3.29** | 3.16 | 4.45 | 3.67 | **3.79** | 3.00 | 4.00 | 4.12 | 4.51 |
| Operating | **12.47** | **10.57** | 11.46 | 16.83 | 12.93 | **12.95** | 11.42 | 13.59 | 12.52 | 15.33 |
| Netback | **31.99** | **27.28** | 55.30 | 28.62 | 15.12 | **28.27** | 26.63 | 32.71 | 25.03 | 29.37 |
| **Total Heavy Oil - Oil Sands** [(4)] ($/bbl) | | | | | | | | | | |
| Price | **59.10** | **51.34** | 81.16 | 61.88 | 44.01 | **58.61** | 53.02 | 60.35 | 57.02 | 65.23 |
| Royalties | **3.50** | **3.37** | 5.68 | 3.40 | 1.57 | **5.72** | 3.62 | 8.80 | 2.87 | 7.68 |
| Transportation and Blending | **2.93** | **3.25** | 3.76 | 1.82 | 2.69 | **2.90** | 2.95 | 2.91 | 2.69 | 3.02 |
| Operating | **14.19** | **13.04** | 14.26 | 16.45 | 13.53 | **12.33** | 11.33 | 12.17 | 12.52 | 13.60 |
| Netback | **38.48** | **31.68** | 57.46 | 40.21 | 26.22 | **37.66** | 35.12 | 36.47 | 38.94 | 40.93 |
| **Heavy Oil - Pelican Lake** [(4)] ($/bbl) | | | | | | | | | | |
| Price | **70.09** | **64.52** | 88.08 | 72.32 | 54.30 | **69.23** | 64.37 | 66.75 | 66.42 | 78.50 |
| Royalties | **4.00** | **1.97** | 6.64 | 4.08 | 3.22 | **3.34** | 2.82 | 4.34 | 2.68 | 3.37 |
| Transportation and Blending | **2.41** | **2.79** | 2.18 | 2.58 | 2.07 | **2.15** | 1.23 | 1.09 | 3.54 | 2.88 |
| Operating | **20.65** | **21.22** | 19.90 | 22.21 | 19.23 | **17.08** | 17.20 | 17.47 | 17.71 | 16.05 |
| Netback | **43.03** | **38.54** | 59.36 | 43.45 | 29.78 | **46.66** | 43.12 | 43.85 | 42.49 | 56.20 |
| **Total Heavy Oil - Conventional** [(4)] ($/bbl) | | | | | | | | | | |
| Price | **70.31** | **64.55** | 87.50 | 71.73 | 57.42 | **69.76** | 64.52 | 67.25 | 66.95 | 79.37 |
| Royalties | **6.08** | **5.31** | 8.83 | 5.50 | 4.65 | **6.06** | 5.26 | 6.05 | 5.46 | 7.33 |
| Transportation and Blending | **2.60** | **2.69** | 2.51 | 2.58 | 2.63 | **2.16** | 1.69 | 1.55 | 3.01 | 2.44 |
| Operating | **19.32** | **19.76** | 18.51 | 20.30 | 18.72 | **16.32** | 14.91 | 17.09 | 16.61 | 16.67 |
| Production and Mineral Taxes | **0.13** | **0.05** | 0.21 | 0.12 | 0.13 | **0.10** | 0.13 | 0.10 | 0.10 | 0.06 |
| Netback | **42.18** | **36.74** | 57.44 | 43.23 | 31.29 | **45.12** | 42.53 | 42.46 | 41.77 | 52.87 |
| **Total Heavy Oil** [(4)] ($/bbl) | | | | | | | | | | |
| Price | **62.23** | **54.61** | 82.97 | 64.91 | 47.82 | **62.05** | 56.22 | 62.45 | 60.13 | 70.08 |
| Royalties | **4.22** | **3.85** | 6.58 | 4.05 | 2.45 | **5.83** | 4.07 | 7.96 | 3.68 | 7.56 |
| Transportation and Blending | **2.84** | **3.11** | 3.40 | 2.06 | 2.67 | **2.67** | 2.60 | 2.50 | 2.79 | 2.82 |
| Operating | **15.62** | **14.70** | 15.47 | 17.63 | 15.01 | **13.56** | 12.33 | 13.66 | 13.80 | 14.65 |
| Production and Mineral Taxes | **0.04** | **0.01** | 0.06 | 0.04 | 0.04 | **0.03** | 0.04 | 0.03 | 0.03 | 0.02 |
| Netback | **39.51** | **32.94** | 57.46 | 41.13 | 27.65 | **39.96** | 37.18 | 38.30 | 39.83 | 45.03 |
| **Light and Medium Oil** ($/bbl) | | | | | | | | | | |
| Price | **86.30** | **82.12** | 100.64 | 86.84 | 76.77 | **78.99** | 75.27 | 76.06 | 76.16 | 88.45 |
| Royalties | **8.28** | **6.58** | 11.01 | 8.61 | 7.05 | **8.09** | 6.92 | 7.53 | 7.98 | 9.94 |
| Transportation and Blending | **4.35** | **5.15** | 4.58 | 4.37 | 3.39 | **2.65** | 2.39 | 2.36 | 3.02 | 2.83 |
| Operating | **16.23** | **17.26** | 15.06 | 16.32 | 16.26 | **15.51** | 15.63 | 16.27 | 14.76 | 15.36 |
| Production and Mineral Taxes | **2.30** | **1.26** | 2.80 | 2.64 | 2.46 | **2.44** | 2.51 | 2.35 | 2.34 | 2.57 |
| Netback | **55.14** | **51.87** | 67.19 | 54.90 | 47.61 | **50.30** | 47.82 | 47.55 | 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 annual cost of condensate for 2013 is as follows: Foster Creek - $42.41/bbl; Christina Lake - $45.25/bbl; Heavy Oil - Oil Sands - $43.77/bbl; Pelican Lake - $15.59/bbl; Heavy Oil - Conventional - $14.60/bbl and Total Heavy Oil - $35.63/bbl.

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Operating Statistics - Before Royalties (continued)

#### Per-unit Results

*(excluding impact of Realized Gain (Loss) on Risk Management)*

| | 2013 | | | | | 2012 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | **Year** | Q4 | Q3 | Q2 | Q1 |
| **Total Crude Oil** *($/bbl)* | | | | | | | | | | |
| Price | **67.05** | **59.41** | 86.41 | 69.75 | 54.02 | **65.76** | 60.10 | 65.37 | 63.91 | 74.22 |
| Royalties | **5.03** | **4.33** | 7.44 | 5.05 | 3.43 | **6.32** | 4.65 | 7.87 | 4.69 | 8.10 |
| Transportation and Blending | **3.14** | **3.47** | 3.63 | 2.57 | 2.82 | **2.66** | 2.55 | 2.47 | 2.84 | 2.83 |
| Operating | **15.74** | **15.15** | 15.39 | 17.34 | 15.27 | **13.99** | 13.00 | 14.22 | 14.03 | 14.81 |
| Production and Mineral Taxes | **0.49** | **0.23** | 0.59 | 0.61 | 0.56 | **0.56** | 0.54 | 0.53 | 0.58 | 0.59 |
| Netback | **42.65** | **36.23** | 59.36 | 44.18 | 31.94 | **42.23** | 39.36 | 40.28 | 41.77 | 47.89 |
| **Natural Gas Liquids** *($/bbl)* | | | | | | | | | | |
| Price | **60.34** | **59.39** | 65.71 | 46.44 | 68.88 | **69.54** | 65.89 | 61.53 | 65.52 | 83.36 |
| Royalties | **1.13** | **1.14** | 1.92 | 1.17 | 0.12 | **1.42** | 1.52 | 1.55 | 1.13 | 1.45 |
| Netback | **59.21** | **58.25** | 63.79 | 45.27 | 68.76 | **68.12** | 64.37 | 59.98 | 64.39 | 81.91 |
| **Total Liquids** *($/bbl)* | | | | | | | | | | |
| Price | **67.01** | **59.41** | 86.28 | 69.61 | 54.10 | **65.79** | 60.13 | 65.35 | 63.92 | 74.28 |
| Royalties | **5.01** | **4.31** | 7.40 | 5.03 | 3.42 | **6.29** | 4.64 | 7.83 | 4.67 | 8.05 |
| Transportation and Blending | **3.12** | **3.45** | 3.61 | 2.55 | 2.81 | **2.65** | 2.54 | 2.45 | 2.82 | 2.81 |
| Operating | **15.65** | **15.06** | 15.29 | 17.24 | 15.19 | **13.90** | 12.93 | 14.14 | 13.93 | 14.71 |
| Production and Mineral Taxes | **0.48** | **0.23** | 0.59 | 0.61 | 0.55 | **0.56** | 0.54 | 0.53 | 0.57 | 0.59 |
| Netback | **42.75** | **36.36** | 59.39 | 44.18 | 32.13 | **42.39** | 39.48 | 40.40 | 41.93 | 48.12 |
| **Total Natural Gas** *($/Mcf)* | | | | | | | | | | |
| Price | **3.20** | **3.21** | 2.83 | 3.50 | 3.25 | **2.42** | 2.97 | 2.30 | 1.92 | 2.50 |
| Royalties | **0.04** | **0.04** | 0.05 | 0.04 | 0.05 | **0.03** | 0.02 | 0.02 | 0.01 | 0.06 |
| Transportation and Blending | **0.11** | **0.11** | 0.10 | 0.08 | 0.15 | **0.10** | 0.10 | 0.08 | 0.08 | 0.13 |
| Operating | **1.16** | **1.23** | 1.13 | 1.16 | 1.14 | **1.10** | 1.29 | 1.08 | 0.98 | 1.08 |
| Production and Mineral Taxes | **0.02** | **0.02** | 0.03 | (0.01) | 0.03 | **0.01** | (0.01) | 0.02 | 0.02 | 0.02 |
| Netback | **1.87** | **1.81** | 1.52 | 2.23 | 1.88 | **1.18** | 1.57 | 1.10 | 0.83 | 1.21 |
| **Total** [1] *($/BOE)* | | | | | | | | | | |
| Price | **51.23** | **47.23** | 63.12 | 52.55 | 42.52 | **46.60** | 45.50 | 46.61 | 43.25 | 50.84 |
| Royalties | **3.44** | **3.07** | 5.02 | 3.35 | 2.38 | **4.00** | 3.08 | 5.02 | 2.84 | 5.00 |
| Transportation and Blending | **2.31** | **2.60** | 2.60 | 1.82 | 2.17 | **1.88** | 1.86 | 1.74 | 1.90 | 2.00 |
| Operating | **12.79** | **12.73** | 12.44 | 13.64 | 12.39 | **11.18** | 11.12 | 11.35 | 10.75 | 11.46 |
| Production and Mineral Taxes | **0.36** | **0.19** | 0.45 | 0.38 | 0.42 | **0.38** | 0.33 | 0.38 | 0.40 | 0.40 |
| Netback | **32.33** | **28.64** | 42.61 | 33.36 | 25.16 | **29.16** | 29.11 | 28.12 | 27.36 | 31.98 |
| **Impact of Long-Term Incentives Costs (Recovery) on Operating Costs** ($/BOE) | **0.12** | **0.06** | 0.23 | 0.07 | 0.10 | **0.16** | 0.05 | 0.32 | (0.17) | 0.42 |
| **Impact of Realized Gain (Loss) on Risk Management** | | | | | | | | | | |
| Liquids *($/bbl)* | **1.09** | **2.77** | (2.02) | 0.72 | 2.62 | **1.39** | 3.35 | 2.02 | 1.64 | (1.67) |
| Natural Gas *($/Mcf)* | **0.32** | **0.36** | 0.38 | 0.18 | 0.39 | **1.14** | 0.89 | 1.24 | 1.39 | 1.03 |
| Total [1] *($/BOE)* | **1.37** | **2.58** | (0.58) | 0.84 | 2.52 | **3.42** | 4.05 | 3.98 | 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.